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Contingent Project Overview

2023-28 Revised Revenue Proposal

Contents

1. Purpose

Our Revised Revenue Proposal proposes six contingent projects to manage the challenges our network will face in the 2023-28 regulatory period where there remains uncertainty on the timing or cost of the project.

This overview documents sets out the need for each of our continent projects, along with the trigger events and supporting evidence to demonstrate that:

- the trigger is likely to occur during the 2023-28 regulatory period
- the need for addition capex that will result from the trigger occurring, and
- the location requiring augmentation.

This overview document does not include the two new contingent projects related to managing the risk of network support solutions, which are described in our 2023-28 Revised Revenue Proposal, for:

- Maintaining reliable supply to North West Slopes Area stage 1, and
- Maintaining reliable supply to Bathurst, Orange and Parkes areas stage 1.

The RIT-T documents detail the need, network investment and timing for these projects.

2. Manage increased fault levels in Southern NSW

The AER's Draft Decision accepted this contingent project on the basis that the project may be required to maintain the quality, reliability and security of supply or meet demand in the 2023–28 period.

We have accepted the AER's Draft Decision for this contingent project, including its changes to the trigger events.

3. Supply to Bathurst, Orange and Parkes Stage 2

Stage 1 of the Maintaining Reliable Supply to the Bathurst, Orange and Parkes areas project has completed its Regulatory Investment Test for Transmission (RIT-T). The preferred option identified in the Project Assessment Conclusion Report (PACR) involves the use of the following to address network voltage constraints:

- Battery Energy Storage Systems (BESS) at Parkes and Panorama (as a non-network solution), and
- Static Synchronous Compensators (STATCOMs) at Parkes and Panorama (as a non-network solution) or a synchronous condenser (as a network investment) at Parkes in the near-term.

It also involves a new 132 kV line between Wellington and Parkes in the future as Stage 2, with the date of this depending on outturn demand forecasts.

Stage 2 of the project is expected to involve a new 132 kV line between Wellington and Parkes, however this will be subject to a future RIT-T which will consider the future demand forecasts. This stage 2 of the project will be triggered by the commitment status of spot loads which are likely to eventuate in the 2023-28 regulatory period.

Stage 1 of the project considered options to manage the forecasted load growth and associated voltage constraints in the area up until 2030 assuming a central demand scenario. This central demand scenario only included spot loads which were considered committed or anticipated at the time of the RIT-T. We consider it likely from submissions that we received to the Stage 1 RIT-T that some spot loads will increase (i.e. expansion of existing loads or new spot loads). It is likely that these load increases will become committed or anticipated in the 2023-28 regulatory period, which will be over and above the central demand forecast considered in the Stage 1 RIT-T. This additional demand will violate thermal constraints in the network.

In particular, we received a submission from [redacted] in response to the Stage 1 RIT-T PADR with three forecasted demand profiles as shown below in [redacted].

[redacted]

We requested [redacted] to provide additional information on each forecasted demand profile considering the committed/anticipated project criteria. Based on this assessment, we only considered that [redacted] low demand scenario was sufficiently certain to be considered committed or anticipated in the RIT-T. Therefore we did not include [redacted] medium and high forecasts within our assessment for Stage 1.

The forecasted demand under medium and high scenarios provided by [redacted] are [redacted] higher than the low scenario. It is likely that this additional demand growth for [redacted] will be committed within the 2023-2028 regulatory period, which would trigger stage 2 of the project.

Our preliminary network studies with [redacted] medium demand forecasts show that this additional demand growth would trigger stage 2 of the project by creating thermal constraints in the Orange area, which will require network augmentation to resolve.

We have also considered the latest demand forecasts available from NSW Government for the Parkes Special Activation Precinct (SAP). The Parkes SAP is one of the most advanced SAP projects in NSW, where additional load growth could be committed within the 2023-2028 regulatory period, which could also trigger stage 2 of the project.

We engaged GHD to independently review our demand forecasts for both Stage 1 and Stage 2 of maintaining reliable supply to Bathurst, Orange and Parkes area. GHD's review of our Stage 2 contingent project found:

- the loads provided to us in customer demand forecasts are certainly probable outcomes of their development plans
- If the demand increases do occur as forecast, they are highly likely to result in a trigger event during the 2023-28 period which would require Stage 2 augmentation to be initiated, and
- Stage 2 augmentation would require additional capital expenditure during the 2023-28 period to ensure reliability of supply to customers can be maintained at acceptable levels across the Bathurst, Orange and Parkes transmission network.

GHD's report is provided as an attachment to our Revised Revenue Proposal.

Table 1 summarises the contingent project triggers, timing and expected augmentation required.

Table 1: Supply to Bathurst, Orange and Parkes area Stage 2

Project details	Particulars
Proposed trigger	(a) One or more of the following: (i) Total forecast demand in the Orange area exceeds 360 MW, or (ii) Total forecast demand in the Parkes area exceeds 120 MW, and (b) Successful completion of a RIT-T that demonstrates that 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.
Current expected timing	Commencement: 2023/24 Completion: 2030/31
Expected augmentation and location	330 kV substation at Orange and or a new Wellington to Parkes 132 kV line

4. Supply to ACT Network Capability

We have regulatory requirements to restore supply to the ACT for special contingency events. The special contingency events are the loss of the entire substation, and the regulatory requirements are stipulated by the Utilities (Technical Regulation) (Electricity Transmission Supply Code) Approval 2016 (No 1) Clause 4.1.1 (1)(d).

The code requires us (from 31 December 2020) to provide continuous electricity supply at 375 MVA to the ACT 132 kV network immediately following a single special contingency event and supply the agreed maximum demand within 48 hours of this event. As per the *2017 Joint Planning Report: ACT Second Electricity Supply Project,* the agreed maximum demand is 657 MVA (632 MW, 180 MVAr).

The latest winter load forecast for the ACT indicates the total forecast winter demand in ACT area for 2023 is 705 MW, which is 73 MW higher than 48 hours agreed maximum demand.

The ACT Utilities Technical Regulator (UTR) has stated in September 2022 that although UTR does not currently have any specific plans to alter the supply capacity restoration time frames, evolving conditions may give rise to review of this aspect.

The latest ACT demand forecast provided by Evoenergy does not account for expected load growth due to the ACT Government Net Zero initiative. The ACT Government's initiative will address the following:

- No new/renewed gas connections in ACT
  The ACT Government has announced that it will phase out fossil fuel gas by 2045, by electrifying Canberra over the next two decades. All new and renewed energy connections for households and businesses will be electrical only (gas is no longer allowed), effective immediately. Fossil fuels accounts for 20% of ACT carbon emission.

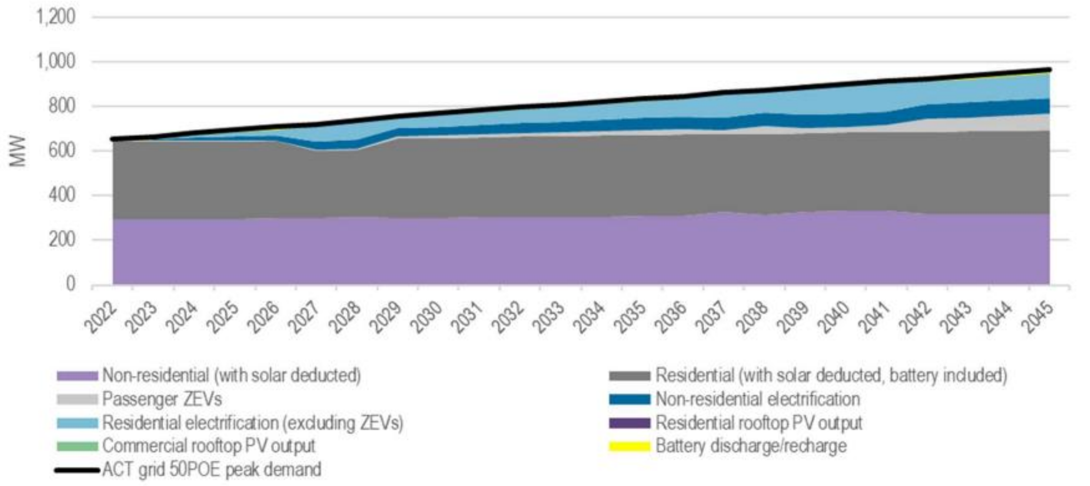
- Electrification of transport
  Transport is the single largest contributor to the ACT's greenhouse emissions, making up over 60% of the total emissions with passenger vehicles contributing to the majority of transport emission. A key measure to reduce transport caused carbon emission is to transition ACT's vehicle fleet to zero emissions vehicles such as electric cars and buses. This Strategy adopts a ZEV (zero electric vehicles) sales target for the ACT of 80-90% by 2030 and outlines the ACT Government's intention to cease registration of new non-ZEVs (internal combustion engines) by 2035.

The above mentioned targets make it clear, that the ACT government is committed to a zero-emissions future. This electrification will dramatically increase electricity demand in the ACT.

Figure 2 below show the assumed peak demand projection based on assumed underlying demand together with the projected uptake of rooftop PV, BESS, ZEVs and other electrification. ACT POE50 peak demand is projected to grow from 654 MW in 2022 to 966 MW in 2045, which is an increase of around 48 per cent over the projection period.[1]

[1] GHD and ACIL Allen, EPSDD 12550182 Economic and Technical Modelling of the ACT Electricity Network, April 2022.

Figure 2: ACT POE50 demand forecast resulting from ACT Government electrification initatives



Note: The contribution of each of the categories are shown at the time and day of the projected 50POE peak demand of the total ACT system. The contribution of rooftop solar PV and home batteries to peal demand is zero or very small. Non-residential electrification includes general natural gas transition of non-residential customer as well as electrification of specific commercial loads of Canberra hospital, Molonglo Commercial Centre, CIT Woden, Bus fleet and Light Rail Stage 2.
Source: ACIL Allen

In addition to the projected demand growth, new government policy announcements will drive even greater load increase in the 2023-28 regulatory period. This load increase will call for new investments, to ensure safe and reliable operation of the transmission network in ACT.

Table 2 summarises the contingent project triggers, timing and expected augmentation required.

Table 2: Supply to ACT network capability

Project details	Particulars
Proposed trigger	(a) Combined demand forecast of the load supplied between Canberra, Stockdill and Williamsdale exceeds 890 MW within 5 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
Current expected timing	Commencement: 2025/26 Completion: 2028/29
Expected augmentation and location	New transformer at Stockdill substation, transmission line cut-ins and connections at Stockdill and Canberra, and reactive support at Stockdill and Williamsdale.

5. Moree Special Activation Precinct

The Regional Growth NSW Development Corporation (RGDC) advised us in August 2021 of a possible Special Activation Precinct (SAP) in the Moree area. The Moree SAP development is a 4,716-hectare precinct being delivered by the Department of Regional NSW (DRNSW), the NSW Government's central agency for regional issues, through the RGDC.

RGDC is looking at developing the Moree SAP starting within the 2023-28 period based on their latest advice as per demand forecasts in Table 3. The preliminary loads are made up of multiple connections and will connect into the network in stages. RDGC sought our establishment of a new 132/22 kV substation to supply the SAP, connecting into the existing 96M Moree to Narrabri 132 kV line.

The Moree demand forecast, as shown in our 2022 TAPR, is up to 28 MW during summer or 37 MW during winter. The load increases identified in Table 3 from the Moree SAP will trigger network constraints in the Moree area.

Table 3: Moree SAP load forecast

[redacted]

We have used this forecast and performed initial network studies of the possible network limitations which could occur with an increase in load at Moree. For the loss of the 9U2 line between Moree and Inverell when the Moree Solar Farm is not generating, the voltage at Moree can drop to below 0.9 per unit, breaching the system standard voltage requirement of NER Schedule S5.1a.4 Power Frequency Voltage. It also has the possibility of causing voltage collapse at times of high demand, losing all the Moree area load.

At times of peak demand the network would require up to 12 MVAr of reactive support from 2024 or 2025, up to 18 MVAr of reactive support from 2026 to 2031, up to 24 MVAr of reactive support from 2028 to 2031 and more beyond 2031, depending on the loading scenario which eventuates. Voltage support, and therefore network augmentation, will be required at Moree with a load increase of 5 MW or more at Moree, making the trigger likely to occur in the 2023-28 regulatory period under all SAP demand scenarios. A forecast load increase of over 23 MW will require significant reactive support.

Adding additional capacitor banks at Moree can alleviate voltage constraints, however beyond that point further reactive support would continue to be required with every additional few MW of load increase, with diminishing effectiveness. A larger dynamic voltage support solution is expected to be the prudent approach to solve the constraint.

In addition to the voltage support, should the Moree SAP be supplied via the Moree 66 kV rather than a new substation on the 96M line, Moree transformer may overload and breach the reliability standard.

We engaged GHD to independently review the demand forecasts for Moree. GHD's review of our Moree SAP contingent project found:

- detailed modelling of the transmission network in the Moree area has shown that the increase in load that will result in voltage issues is now only 5 MW
- there is now a much higher probability that demand resulting from development of the Moree SAP will require augmentation, and
- augmentation during the 2023-28 period will be required if any of the low, medium or high scenarios of demand from the SAP are realised.

GHD's report is provided as an attachment to our Revised Revenue Proposal.

Table 4 summarises the contingent project triggers, timing and expected augmentation required.

Table 4: Moree Special Activation Precinct

Project details	Particulars
Proposed trigger	(a) total demand forecast in the Moree area exceeds 42 MW, 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
Current expected timing	Commencement: 2026/27 Completion: 2027/28
Expected augmentation and location	Dynamic voltage support at Moree

6. Maintaining reliable supply to the North West Slopes area Stage 2

The Maintaining Reliable Supply to the North West Slopes area RIT-T considered augmentation resulting from demand growth in the region, including stages 1 and 2 of the Narrabri Gas project. The preferred solution identified in the PACR involves the use of a Battery Energy Storage System (BESS) in the Gunnedah area as a non-network solution and the installation of a third transformer at Narrabri in the near-term as Stage 1 for the project. It also involves a rebuilding of the 132 kV line between Gunnedah and Tamworth 330 as a double circuit, and an uprating of the 132 kV line between Boggabri North and Narrabri as Stage 2, with the timing based on the second portion of the expected load growth in the area, in particular the Narrabri gas project demand.

We engaged GHD to independently review our demand forecasts applied in the RIT-T. GHD found that we developed realistic load forecasts and considered that we had correctly applied the AER definition for committed and anticipated loads to submissions made by proponents in order to develop the load forecast scenarios.

Under Stage 1 of the project, the BESS is sized so that the forecasted load growth in the area up to 2029 under the central scenario of PACR can be managed without violating any voltage or thermal constraints. However, these works will not be sufficient to meet the further thermal and voltage constraints within the area for Stage 2 of the project. The augmentation works identified in the RIT-T for Stage 2 will need to commence within the 2023-28 regulatory period to meet the likely demand growth.

We have included Stage 2 of this project as a contingent project because this investment is dependent on future demand growth in the area becoming committed from the Narrabri Gas project. The RIT-T has shown that this demand forecast is likely to eventuate, and that augmentation will be required in the Narrabri area as a result within the 2023-28 period.

Table 5 summarises the contingent project triggers, timing and expected augmentation required.

Table 5: Maintaining reliable supply to the North West Slopes area Stage 2

Project details	Particulars
Proposed trigger	One or more of the following: (a) The summated maximum demand forecast for Narrabri and Gunnedah areas exceeds 120 MW within the next 6 years, or (b) Commitment of the Narrabri Gas Project.
Current expected timing	Commencement: 2025/26 Completion: 2029/30
Expected augmentation and location	Rebuilding existing line 969 and upgrading Line 9UH in Narrabri area

7. Maintaining power system security in NSW

The Australian Energy Market Operator's (AEMO) 2022 Integrated System Plan (ISP) projects a rapid transition from fossil fuel to renewable energy generation in the National Electricity Market (NEM). The Step Change scenario, identified as the most likely scenario, projects that coal generators in the NEM are likely to retire two to three times faster than currently anticipated. ISP modelling suggests that 60% of the NEM's coal generators will withdraw from NEM by 2030, in contrast to the 21% projected by thermal plant owners. In NSW, AEMO projects 5,570 MW of coal generation will retire by FY30 under the Step Change scenario and 6,940 MW under the Hydrogen Superpower scenario. These coal synchronous generators are currently critical to maintaining the security of the power system through their provision of fault current and inertia, which supports voltage and small signal stability and power quality.

We have undertaken power system studies to identify needs and options to maintain system security as NSW's coal generators retire. System security needs include but are not limited to voltage stability, small signal stability and power quality, in addition to system strength and inertia. Our analysis has identified that the network will reach stability limits with the projected reduction in NSW coal generation capacity. Suitable network augmentation options are being identified to manage these constraints. While some needs have clearly been identified, it is expected that further system security needs will become apparent as we and the industry, including AEMO, undertake further studies on the security of the power system as coal generators withdraw.

According to the National Electricity Rules (NER) S5.1.4, a Transmission Network Service Provider (TNSP) must plan and design its transmission system and equipment for control of voltage such that the minimum steady state voltage magnitude, the maximum steady state voltage magnitude and variations in voltage magnitude are consistent with the levels stipulated in clause S5.1a.4 of the system standards. Our analysis has identified that the retirement of thermal generators coupled with the projected drop in minimum demand and change in generation dispatch patterns in NSW is likely to cause violations to the NER S5.1.4 requirements.

We identified that augmentation to install new dynamic reactive power compensation devices will be needed in the Sydney region to solve these voltage violations. In addition to this, modification of existing, and the installation of new shunt compensators are also required in this area.

The retirement of a large number of synchronous generators from the system will impact the small-signal stability of remaining generators and other components, including synchronous condensers. Addition of new technologies such as grid-forming inverters and the inclusion of synchronous condensers to mitigate inertia and fault level shortfalls that appear will also impact the small-signal stability of the system and will cause violations to the damping and halving time requirement of NER S5.1.8 and S5.1a.3.

The reduction in fault level in the network due to the retirement of coal-based thermal synchronous generators will cause some existing protection systems to incorrectly operate, potentially leading to significant safety issues. An example of this is the ineffectiveness of Under-Frequency Load Shedding (UFLS) schemes during reverse power flow in feeders. In addition, the reduction in fault level will impact the normal operation of protection systems, including distance protection and over-current protection. Retirement of synchronous generators will hence lead to violations to the NER S5.1.9 requirements.

Power quality issues typically refer to "any power problem manifested in voltage, current, or frequency deviations that result in failure or mal-operation of customer equipment". Recent technologies such as renewable energy sources, microgrids, electric vehicle chargers and inverters are creating a rise in non-linear loads, and coupled with a reduction in thermal generation, will cause problems including over/under voltage, harmonics, voltage fluctuations, voltage unbalance and hence can cause violations to the NER s5.1.4 – s5.1.7.

Table 6 summarises the contingent project triggers, timing and expected augmentation required.

Table 6: Maintaining power system security in NSW project

Project details	Particulars
Proposed trigger	(a) One or more of the following: (i) The announcement of the planned retirement of over 500 MW of synchronous generation capacity in the NSW Hunter, Central Coast and Central West regions in

Project details	Particulars
	the following seven years, as recorded in AEMO's Generation Information page, or (ii) AEMO projects in their most likely ISP scenario that more than 500 MW 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% of time in each financial year is projected to fall below six units. (b) Successful completion of a RIT–T that demonstrates that transmission investment is the preferred option (or part of the preferred option)
Current expected timing	Commencement: 2023/24 Completion: 2028/29 August 2025 (Eraring), as projected in the 2022 ISP Step Change scenario: 2027/28 (Vales Point), 2028/29 – 2033/34 (Bayswater), 2039/40 (Mt Piper)
Expected augmentation and location	Dynamic and static reactive power compensation in the Sydney area