AEMO responses to Questions on Notice

Senate Select Committee on Energy Planning & Regulation in Australia

November 2024

Question one

SENATOR DAVID VAN: AEMO to describe its understanding of how RIT-Ts are applied by TNSPs in relation to actionable ISP projects.

Answer

The Regulatory Investment Test for Transmission (RIT-T) is an economic benefit test that an electricity transmission network service provider (TNSP) must complete for proposed large transmission network investments.

The main purpose of the RIT-T is to require the TNSP to compare different options, including non-network options, to identify the credible investment option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the market (the “preferred option”): National Electricity Rules (NER) clause 5.15A.1(c).

A TNSP must complete the RIT-T to apply to the Australian Energy Regulator (AER) to allow the TNSP to recover revenue from its customers to deliver the project.

The NER and AER’s *Cost benefit analysis guidelines* set out the different RIT-T processes for projects which are actionable ISP projects and other projects.

NER clause 5.15A.3 and rule 5.16A and the AER’s guidelines set out how the RIT-T process must be undertaken for actionable ISP projects. A TNSP must complete the following process to apply to the AER for cost recovery for the project:

1. In an ISP, AEMO may identify an ‘actionable ISP project’ that meets an identified need as part of the Optimal Development Path (ODP): NER clause 5.22.6(a).

2. The relevant TNSP must complete the RIT-T for the proposed project (except in limited circumstances set out in NER): NER clause 5.16A.3. TNSPs must comply with NER rule 5.16A and the AER’s *Cost benefit analysis guidelines* section 4 in applying the RIT-T. The TNSP must produce and consult on a Project Assessment Draft Report (PADR), and produce a Project Assessment Conclusions Report (PACR), which includes the proposed preferred option: NER clause 5.16A.4.

3. Further, the NER 5.16A.4 (d) states that the PADR must:
    1. include the matters required by the *Cost Benefit Analysis Guidelines*;
    2. adopt the *identified need* set out in the *Integrated System Plan* (including, in the case of proposed *reliability corrective action*, why the *RIT-T proponent* considers *reliability corrective action* is necessary);
    3. describe each *credible option* assessed;

4. include a quantification of the costs, including a breakdown of operating and capital expenditure for each *credible option* (subject to [clause 5.16A.7(c)]);
5. assess market benefits with and without each *credible option* and provide accompanying explanatory statements regarding the results;
6. if the *RIT-T proponent* has varied the *ISP parameters*, provide demonstrable reasons in accordance with 5.15A.3(b)(7)(iv);
7. identify the proposed *preferred option* that the *RIT-T proponent* proposes to adopt;
8. for the proposed *preferred option* identified under subparagraph (7), the *RIT-T proponent* must provide:
   i. details of the technical characteristics; and
   ii. the estimated construction timetable and commissioning date;
9. if each of the following apply to the *RIT-T project*:
   i. the estimated capital cost of the proposed *preferred option* is greater than $100 million (as varied in accordance with a *cost threshold determination*); and
   ii. *AEMO* is not the sole *RIT-T proponent*, include the *RIT reopening triggers* applying to the *RIT-T project*; and
10. if applicable, set out the costs of *early works* incurred but not included under clause 5.16A.7(c).

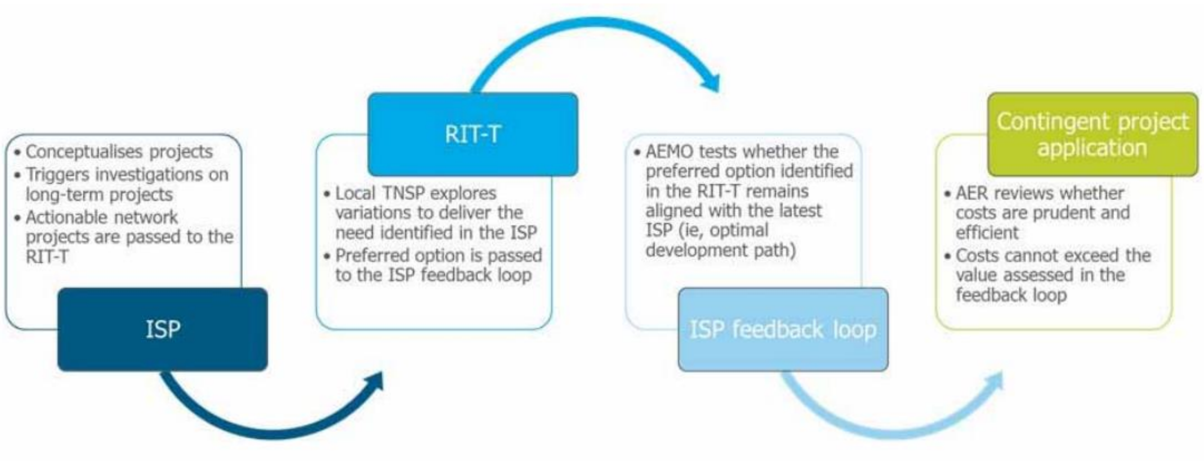
4. The TNSP must request AEMO to confirm that the preferred option meets the identified need, and remains aligned with the ODP in the most recent ISP: NER clause 5.16A.5(b). This is called a feedback loop assessment. The feedback loop assessment does not review the TNSP's RIT-T modelling.

5. AEMO must comply with the AER's *Cost benefit analysis guidelines* section 3.5.3 in undertaking the feedback loop assessment.

6. If AEMO provides feedback loop confirmation, the TNSP is eligible to submit a contingent project application to the AER for cost recovery for the project: NER clauses 5.16A.5 and 6A.8.2.

7. The AER must comply with NER clause 6A.8.2 in consulting and deciding on the application. If the AER amends the TNSP's revenue determination to include the revenue required for the project, it must have regard to the expenditure that would be incurred by an efficient and prudent TNSP.

This process has been summarised by the AEMC (Transmission planning and investment - Stage 2, Final report, 27 October 2022, p47) as follows:



Source: AEMC.

As required by the Rules, AEMO publishes summaries of RIT-T publications, together with links to TNSPs' RIT-T consultation pages, on AEMO's website. See current and closed consultations at https://aemo.com.au/consultations/current-and-closed-consultations

Question two

SENATOR DAVID POCOCK: How often has there been curtailment under the third tier of the minimum system load? Outline all the times there has been curtailment.

Answer

To date, there has been three instances whereby solar curtailment has been undertaken as instructed by AEMO to maintain power system security.

A table detailing all instances of solar curtailment instructed by AEMO has been included below.

Date	Region
14 March 2021	**South Australia** AEMO issued a NER clause 4.8.9 instruction to Electranet to maintain operational demand in South Australia. This instruction resulted in SA Power Networks curtailing distributed photovoltaic (DPV) generation. Further information is available in the incident report: Maintaining operational demand in South Australia on 14 March 2021
13–19 Nov 2022	**South Australia** AEMO issued a NER clause 4.8.9 instruction to ElectraNet to maintain operational demand in South Australia. This instruction resulted in SA Power Networks curtailing distributed photovoltaic (DPV) generation. Further information is available in the incident report: AEMO (May 2023) Trip of South East – Tailem Bend 275 kV lines on 12 November 2022
15 February 2024	**South Australia** AEMO issued a NER clause 4.8.9 instruction to ElectraNet to maintain operational demand in South Australia. This instruction resulted in SA Power Networks curtailing distributed photovoltaic (DPV) generation. Further information will be available in the incident report when published: Power System Operating Incident Reports

Question three

SENATOR DAVID POCOCK: On curtailment, have you done a risk and probability analysis. Provide the analysis.

Answer

AEMO has undertaken analysis regarding the risks posed by minimum system load conditions and the need for arrangements to manage power system security under these conditions. The most recent analysis of these risks is detailed in Section 7.6 (pp 109–113) of the 2024 Electricity Statement of Opportunities (ESOO).

Further detail regarding the requirements to manage of minimum system load conditions has been included in a range of market and technical publications in recent years, including:

- AEMO Minimum System Load (MSL) factsheet
- NEM Lack of Reserve Framework Report – 1 July to 30 September 2024, Section 4 (pp20–21)
- The Engineering Roadmap FY2025 Priority Actions Report, Appendix A1 (page 33)
- Technical Report - Minimum operational demand thresholds in South Australia May 2020

Question four

SENATOR MATT CANAVAN: [In reference to quote]: On what basis were you saying that 60 per cent of coal generation would be retired by the end of the decade?

Answer

This statement was made by AEMO CEO Daniel Westerman in his speech at the 2022 Australian Clean Energy Summit event. The 60% statistic is from the 2022 ISP:

> "*Coal-fired generation withdrawing faster than announced, with 60% of capacity withdrawn by 2030. Current announcements by thermal plant owners suggest that about 8 gigawatts (GW) of the current 23 GW of coal-fired generation capacity will withdraw by 2030. In the Step Change scenario, assessed by stakeholders as most likely, ISP modelling suggests that 14 GW would withdraw by 2030*." 2022 ISP, Executive Summary (page 9).

Information about the potential outlook for coal capacity at the time in July 2022 is available in the 2022 ISP, Figure 16 Coal capacity, NEM (GW, 2009–10 to 2049–50), page 50.

Question five

SENATOR DAVID VAN: What are the benefits of ISP projects, particularly interconnector projects?

Answer

The ISP benefits assessment is undertaken in accordance with the AER Cost Benefit Guidelines.

Based on the 2024 ISP, the most significant market benefits are comprised of:

- ***Capital deferral of generation and storage*** *– There is diversity in resources (e.g. wind generation) and electricity demand (e.g. due to variations in weather dependent consumption such as heating and cooling, and due to variations in time zones) across the NEM. Additional interconnector capacity allows generation and storage which is surplus to local requirements to be shared across the NEM, resulting in a lower requirement for capital investment in generation and storage to meet the reliability standard.*

- ***Fuel costs*** *– With additional interconnection, less fuel is required (e.g. coal and gas) because renewable generation and storage can be shared during times of surplus availability.*

- ***Operating & maintenance costs*** *– With a lower investment in generator and storage capital (discussed above), there is a lower requirement for operating and maintenance due to the reduction in net generation and storage capacity.*

- ***Unserved energy & demand side participation*** *– Costs associated with demand reduction due to changes in voluntary load curtailment (through demand side participation), and involuntary load shedding costs, valued at the value of customer reliability.*

- ***Emissions reduction benefits*** *– The value of reducing greenhouse gas emissions from fossil-fuelled generation, calculated in accordance with Energy Ministers' value of greenhouse gas emissions reduction.*

The ISP focuses on the benefits of development paths which is a series of network projects together with generation and storage development. These development paths include Renewable Energy Zone developments as well as interconnectors.

Interconnectors support sharing surplus generation and storage between market regions, thereby minimising duplication of investments in firming capacity in each region to support coincident peaks in demand and/or troughs in generation availability.

The overall market benefits from the Optimal Development Path in the 2024 ISP are set out in the table below. These are determined by comparison to a development path which does not include any additional transmission network investment and therefore includes significantly more generation and storage development. This approach is set out in the AER Cost Benefit Guidelines.

Table 1 – Market benefits for transmission projects in the 2024 ISP

Real July 2023 dollars ($m)	Scenario-weighted gross benefits (NPV, $billion)
Generator and storage capital deferral	15.38

Real July 2023 dollars ($m)	Scenario-weighted gross benefits (NPV, $billion)
Fuel costs	17.07
Operating & maintenance costs	2.69
Unserved energy & demand side participation	-0.27
Gross market benefits excluding emissions (Sum of rows above)	34.87
Emissions reduction benefits	3.31
Gross market benefits (Gross market benefits + Emissions reduction benefit)	38.18
Transmission costs	(16.35)
Total net market benefits (Gross market benefits – transmission costs)	21.83

These gross benefits of $38 billion more than pay for the cost of network investments of $16 billion, delivering net market benefits to consumers of $18.5 billion plus $3.3 billion of emissions reduction.