REVIEW

Australian Energy Market Commission

FINAL REPORT

LAST RESORT PLANNING POWER - 2019

28 NOVEMBER 2019

INQUIRIES

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

E aemc@aemc.gov.au
T (02) 8296 7800
F (02) 8296 7899

Reference: EPR0077

CITATION

AEMC, Last resort planning power - 2019, Final report, 28 November 2019

ABOUT THE AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

SUMMARY

1 The interconnectedness of the transmission network is fundamental to the national electricity market (NEM). It allows electricity to flow across the entire NEM, connecting Queensland, New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania, and facilitates the NEM as a single interconnected market.

2 The last resort planning power (LRPP) is a power conferred on the Australian Energy Market Commission (Commission or AEMC) in the National Electricity Rules (NER) to make sure that sufficient investment is being provided to efficiently transport electricity between adjacent regions of the NEM.

3 The purpose of the LRPP is to "ensure timely and efficient inter-regional transmission investment is being provided for the long term interests of consumers of electricity."[1]

4 Because it is a last resort mechanism, the LRPP is designed to only be utilised where there is a clear indication that the standard planning processes have resulted in a planning gap regarding the transmission infrastructure for transporting electricity between NEM regions.

5 The Commission must annually assess whether or not it should exercise the LRPP and report on the matters it has considered in deciding whether or not to exercise the LRPP. To complete this assessment, the AEMC compared projects identified in the transmission network service providers' (TNSPs') 2019 transmission annual planning reports and regulatory investment for transmission (RIT-T) documents with the constraints on the transmission network forecast by AEMO in the 2018 National Transmission Network Development Plan (NTNDP) and the 2018 Integrated System Plan (ISP).[2]

6 The AEMC has decided not to exercise the LRPP in 2019. This is because the AEMC's analysis has found that TNSPs are adequately considering the inter-regional constraints that have been identified by AEMO in its role as the national transmission network planner.

7 The AEMC notes that TNSPs across the NEM have been carrying out RIT-Ts to explore the possible benefits of interconnector augmentations or new interconnector developments, including in relation to the Queensland - NSW interconnector (QNI), Victoria - NSW interconnector (VNI), the new South Australia - NSW interconnector (Project EnergyConnect) and the new Tasmania - Victoria interconnector (Marinus Link).

8 The Energy Security Board (ESB) is currently progressing a work program to convert the ISP into an actionable long-term strategic plan. This process involves reforms to the transmission planning framework in the NER. The Commission has worked closely with the ESB on this project.

9 The ESB published draft rules for consultation on these changes in November 2019.[3] These draft changes will speed up the RIT-T process for projects that are identified in the ISP. They

1 Rule 5.22(b) of the NER.

2 The AEMC regarded the ISP as the previous NTNDP for the purposes of this review.

3 COAG Energy Council 2019, Consultation on Draft ISP Rules, viewed 21 November 2019, http://www.coagenergycouncil.gov.au/publications/consultation-draft-isp-rules

will also replace the LRPP with new requirements on transmission businesses to publish a RIT-T draft report within a period specified by AEMO in the ISP.[4]

4 Energy Security Board, *Converting the Integrated System Plan into action*, November 2019, pp. 19-20.

CONTENTS

APPENDICES

TABLES

FIGURES

1 INTRODUCTION

The national electricity market (NEM) is one of the longest interconnected power systems in the world. It comprises almost 40,000km of transmission lines across six Australian states and territories. The ability to transfer electricity between Queensland, New South Wales, the Australian Capital Territory, Victoria, Tasmania and South Australia is fundamental to the operation of the NEM as a single wholesale electricity market.[5]

The Australian Energy Market Commission (Commission or AEMC) holds a last resort planning power (LRPP), conferred on it in the National Electricity Rules (NER), to help ensure that sufficient investment in transmission infrastructure is occurring to transport electricity across the NEM. This power enables the AEMC to direct a network business to undertake a regulatory investment test - weighing up the costs and benefits of meeting an identified need - on projects to address network congestion, if they are not already underway.

The AEMC is required to annually assess and report on whether it should exercise the LRPP.[6] This report meets that obligation by describing the matters the Commission has taken into account when undertaking the 2019 LRPP review and the Commission's decision on whether to exercise the LRPP in 2019.

Chapter 2 of this report outlines the purpose of the LRPP. It also describes the bearing on this 2019 LRPP review of: the Australian Energy Market Operator (AEMO)'s 2018 National Transmission Network Development Plan (NTNDP) and Integrated System Plan (ISP), as well as the Energy Security Board (ESB)'s work on actioning the ISP and incorporating the ISP into the NER and the transmission planning framework.

Chapters 3 to 6 in turn list the constraints that AEMO expects to affect the flows of electricity between NEM regions, based on the 2018 ISP and the 2018 NTNDP. Each chapter then assesses if these expected inter-regional constraints are being addressed by the relevant transmission network service provider (TNSP), and evaluates whether there is evidence of insufficient consideration of an inter-regional constraint that would require the Commission to direct a TNSP under its LRPP. Each chapter highlights major interconnector upgrades (such as for the Queensland - NSW interconnector) and new proposed interconnectors (such as Project EnergyConnect) and their link to identified constraints.

The appendices of this report provide a detailed explanation of interconnection and constraints (Appendix A), the Commission's approach to the LRPP (Appendix B), the AEMC's LRPP obligations (Appendix C), the planning reports considered by the Commission as part of the LRPP process (Appendix D) and a high-level description of various technologies discussed in the report and how they are used for power systems (Appendix E).

5 See Appendix A for a more detailed explanation of interconnection and inter-regional constraints in the NEM.

6 Rule 5.22(m) of the NER.

2 BACKGROUND

2.1 Purpose of the LRPP

The purpose of the last resort planning power (LRPP) is to "ensure timely and efficient inter-regional transmission investment is being provided for the long term interests of consumers of electricity."[7]

Being a last resort mechanism, the LRPP is designed only to be utilised where there is a clear indication that the standard planning processes have resulted in a planning gap regarding the transmission infrastructure for transporting electricity between national electricity market (NEM) regions.[8]

The LRPP is not a power to direct investment in the transmission network. Rather it is the power to direct that the regulatory investment for transmission (RIT-T) be applied to a project that is designed to address an identified problem. The referred project or projects could be identified by the AEMC or the network service provider, or based on advice by the Australian Energy Market Operator (AEMO).

The Commission must annually assess whether or not it should exercise the LRPP and report on the matters it has considered in deciding whether to exercise the LRPP.[9] This assessment must consider the AEMO's two most recent National Transmission Network Development Plans (NTNDPs), and transmission network service providers' (TNSPs') transmission annual planning reports to ascertain whether TNSPs are taking appropriate steps to address the future constraints that AEMO identifies for national transmission flow paths (inter-regional constraints).

This report meets the Commission's LRPP obligations by specifying the matters the Commission has considered, and its decision, about whether or not to exercise the LRPP in 2019.[10]

2.2 Recent developments

Several recent developments regarding transmission planning and investment have been pertinent to the conduct of this 2019 LRPP review.

2.2.1 Implications of the ISP

As outlined previously, under the National Electricity Rules (NER), the Commission must consider AEMO's current NTNDP and its previous NTNDP in the Commission's annual assessment of whether it is necessary to exercise the LRPP.

In December 2018, AEMO published a 2018 NTNDP, which the Commission has taken to be the current and most recent NTNDP for the purposes of the 2019 LRPP review.

7 Rule 5.22(b) of the NER.

8 See Appendix B for a more detailed explanation of the AEMC's approach to exercising the LRPP.

9 See Appendix C for further details on the Commission's LRPP obligations.

10 The 2019 LRPP review has also considered the National Electricity Market Constraint Report 2018 Electronic Material published by AEMO as well as RIT-T and other relevant documents as part of this assessment.

The Commission has regarded the 2018 Integrated System Plan (ISP) which was published in July as the previous NTNDP.[11]

AEMO expects to publish a draft 2019-2020 ISP in December 2019 as a substitute for publishing a 2019 NTNDP,[12] and a final 2019-20 ISP in June 2020.[13]

2.2.2 The ESB's work on converting the ISP into action

The Energy Security Board (ESB) is progressing a work program to convert the ISP into an actionable long-term strategic plan. This process involves regulatory and legal reforms to the transmission planning framework.

The ESB released a package of draft rule changes in November 2019. One of the proposed changes involves the AEMC no longer holding a last resort planning power. This is because under the new proposed ISP framework, TNSPs would have an obligation to conduct a RIT-T for ISP projects identified by AEMO and publish a project assessment draft report (PADR) within specified timeframes. As a result, these obligations would achieve a similar purpose as the current LRPP function, and would therefore make the LRPP obsolete.

While the existing transmission planning framework remains in place, the Commission will continue to discharge its obligations regarding the LRPP.

2.2.3 Major interconnection projects

TNSPs across the NEM have been carrying out RIT-Ts to explore the possible benefits of interconnector augmentations or new interconnector developments. These initiatives include the following:

- TransGrid and Powerlink published a PADR in September 2019 providing a preferred option for upgrading interconnector flows through the Queensland - NSW interconnector (QNI). Medium-term options discussed in their earlier QNI project specification consultation report (PSCR) will be assessed further as part of a separate RIT-T process in the future.
- AEMO and TransGrid published a PADR in August 2018 with a preferred option to increase flows between Victoria and New South Wales through the Victoria - NSW (VNI) interconnector.
- AEMO is preparing to initiate a RIT-T process for a new proposed KerangLink interconnector (formerly known as SnowyLink South) connecting Victoria and New South Wales.

11 On 21 November 2018, the AEMC sought further confirmation from AEMO, in its role as national transmission planner, of the inter-regional transmission constraints which AEMO considers need to be addressed by the relevant TNSPs. AEMO responded to the Commission's request on 27 November 2018. For more information, see: AEMO, *Last Resort Planning Power request for information - expected inter-regional constraints*, letter, accessed via https://www.aemc.gov.au/sites/default/files/2018-12/AEMO%27s%20letter%20of%20reply%20-%2027%20November%202018_0.pdf.

12 AEMO 2019, 2019-20 Integrated System Plan, viewed 23 October 2019, https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2019-Integrated-System-Plan

13 Ibid.

- ElectraNet published a project assessment conclusions report (PACR) in February 2019 that discussed their preferred option for a new Project EnergyConnect interconnector connecting South Australia to New South Wales.
- TasNetworks published a PSCR in July 2018 exploring options for a Marinus Link interconnector between Tasmania and Victoria.

Further details about these initiatives and their links to identified constraints are provided in chapters 3-6 of this report.

3 REVIEW OF QUEENSLAND - NEW SOUTH WALES CONGESTION

> BOX 1: SUMMARY OF FINDINGS
>
> All transmission network inter-regional constraints expected to affect flows between Queensland and New South Wales are being addressed by the relevant TNSPs in their transmission annual planning reports and RIT-T documents. This includes all inter-regional constraints relevant to the Queensland – New South Wales (QNI) interconnector and those relevant to the Terranora interconnector. As such, there is no evidence of insufficient consideration of an inter-regional transmission constraint that would require the Commission to direct a TNSP under its last resort planning powers.

This chapter provides the Commission's analysis of whether there are any significant inter-regional constraints affecting the flows between Queensland and New South Wales that are not being addressed by the relevant TNSPs. The chapter:

- Describes QNI and the Terranora interconnector, the two interconnectors that transport electricity in the NEM between Queensland and New South Wales.
- Reviews Powerlink and TransGrid's 2019 transmission annual planning reports (TAPRs) and the *Expanding NSW-QLD transmission transfer capacity* PADR regarding projects that address inter-regional constraints affecting QNI and the Terranora interconnector.[14]
- Compares the projects that Powerlink and TransGrid identify in these reports with AEMO's expected inter-regional constraints to identify if there are any 'gaps' where a TNSP has not responded to an expected inter-regional constraint identified by AEMO.

3.1 The Queensland - New South Wales interconnector (QNI)

QNI is a 330 kV alternating current double circuit interconnection that runs between Bulli Creek in Queensland and Dumaresq in New South Wales.[15]

QNI currently has a nominal capacity of:[16]

- 1025 MW from Queensland to New South Wales, mainly due to transient stability limits. When Phasorpoint equipment is in service, it can help manage oscillatory stability and the associated limit is 1200 MW.
- 310 MW from New South Wales to Queensland, due to voltage collapse.[17]

14 TransGrid and Powerlink, *Expanding NSW-QLD transmission transfer capacity – Project Assessment Draft Report,* September 2019.

15 AEMO, *Interconnector Capabilities*, November 2017, p. 4.

16 Ibid, pp. 4-5. See also TransGrid and Powerlink, *Expanding NSW-QLD transmission transfer capacity – Project Assessment Draft Report,* September 2019, p. 66.

17 Ibid. Transfers in this direction are limited to between 200 and 400 MW when Kogan Creek is in service and can reach up to 600 MW with Kogan Creek out of service and other large Queensland generators operating at a lower output.

3.2 The Terranora interconnector

The Terranora interconnector comprises the two 110 kV lines from Terranora in New South Wales to Mudgeeraba in Queensland.[18] The controllable element of the interconnector is a 180 MW direct current link between Terranora and Mullumbimby (both in New South Wales), known as Directlink.[19]

Directlink consists of three separate bipolar current underground cables with a capacity of 60 MW each.[20] While geographically located in NSW, Directlink effectively delivers electricity between New South Wales and Queensland due to its position in the transmission network.[21] Due to the local load connected around Terranora, the nominal capacity for the Terranora interconnector differs from that of Directlink, which has a nominal capacity of 180 MW in each direction.[22]

The Terranora interconnector currently has a nominal capacity of:

- 107 MW from New South Wales to Queensland
- 210 MW from Queensland to New South Wales.[23]

3.3 Expected inter-regional constraints and TNSP proposed projects

3.3.1 Sources considered

This section examines whether all expected inter-regional constraints affecting flows between Queensland and New South Wales are being adequately addressed by the relevant TNSP.

It presents the inter-regional constraints that AEMO in its national transmission planning role expects are likely to affect flows between Queensland and New South Wales into the future. The sources used in the analysis are AEMO's 2018 ISP and 2018 NTNDP.

The section then identifies projects that TransGrid and Powerlink propose in their 2019 annual planning reports to address these expected inter-regional constraints, as well as the projects proposed in TransGrid and Powerlink's *Expanding NSW-QLD transmission transfer capacity* PADR, which was published in September 2019.

It then compares the projects that TransGrid and Powerlink identify in their annual planning reports with AEMO's expected inter-regional constraints, to identify if there are any 'gaps' where a TNSP has not responded to the expected inter-regional constraint identified by AEMO.

18 AEMO, *Interconnector Capabilities*, November 2017, p. 4.

19 Contrary to an alternating current interconnector, where the voltage and current are at any point sinusoidal, in a direct current interconnector, the power is transferred using constant voltage and current.

20 AEMO, *Interconnector Capabilities*, November 2017, p. 4.

21 APA Group, Electricity Interconnectors, viewed 10 September 2018, https://www.apa.com.au/our-services/other-energy-services/electricity-transmission-interconnectors.

22 TransGrid and Powerlink, *Expanding NSW-QLD transmission transfer capacity – Project Assessment Draft Report,* September 2019, p. 66.

23 AEMO, *Interconnector Capabilities*, November 2017, p. 4.

The section also identifies projects that TransGrid and Powerlink propose to assist inter-regional transfers, but which do not directly address constraints identified in AEMO's national transmission planning documents.

The Commission's analysis for QNI is presented first, followed by analysis of the Terranora interconnector.

3.3.2 Findings: Queensland – New South Wales interconnector (QNI)

AEMO identified **three expected inter-regional constraints on QNI** in the 2018 ISP and the 2018 NTNDP. Table 3.1 presents each inter-regional constraint identified by AEMO involving QNI and the TNSP projects addressing that constraint.

One of these expected constraints involves New South Wales to Queensland exports being limited by a voltage collapse limit on the loss of the largest generating unit in Queensland (presented as QNI #1 in Table 3.1).[24] This constraint was identified in AEMO's 2018 NTNDP.[25]

The second expected inter-regional constraint (presented as QNI #2 in Table 3.1) involves flows from New South Wales to Queensland being limited by the thermal capacity of the Liddell - Muswellbrook - Tamworth and Liddell - Tamworth 330 kV lines.[26] This constraint was identified in AEMO's 2018 ISP as corresponding to the augmentation driver of increasing transfer between Queensland and New South Wales.[27] The constraint was also identified in AEMO's 2018 NTNDP.[28]

The third expected constraint (presented as QNI #3 in Table 3.1) involves New South Wales to Queensland export being limited by the transient stability limits for a fault on either a Bulli Creek - Dumaresq or an Armidale - Dumaresq 330 kV circuit.[29] This constraint was identified in AEMO's 2018 ISP as corresponding to the augmentation driver of increasing transfer between Queensland and New South Wales.[30] The constraint was also identified in AEMO's 2018 NTNDP.[31]

TransGrid and Powerlink have provided **six possible proposals** in their September 2019 PADR to augment the northern New South Wales and south Queensland transmission network and thereby increase the capacity of QNI.[32]

---

24 See the constraint with the equation ID N^^Q_NIL_B1, 2, 3, 4, 5, 6 & N^Q_NIL_B in AEMO, *The National Electricity Market Constraint Report 2018 Electronic Material*, June 2019, Interconnector Binding tab.

25 AEMO, *National Transmission Network Development Plan,* December 2018, p. 27.

26 See the constraint with the equation ID N>>N-NIL__3_OPENED in AEMO, *The National Electricity Market Constraint Report 2018 Electronic Material*, June 2019, Interconnector Binding tab.

27 AEMO provided confirmation to the AEMC in correspondence on 7 September 2018. For more details regarding this and other drivers which are not related to inter-regional flows, see AEMO, *ISP Appendices*, July 2018, pp. 58-60; p. 68.

28 AEMO, *National Transmission Network Development Plan,* December 2018, p. 27.

29 See the constraint with the equation ID Q:N_NIL_AR_2L-G & Q::N_NIL_AR_2L-G in AEMO, *The National Electricity Market Constraint Report 2018 Electronic Material*, June 2019, Interconnector Binding tab.

30 AEMO provided confirmation to the AEMC in correspondence on 7 September 2018. For more details regarding this and other drivers which are not related to inter-regional flows, see AEMO, *ISP Appendices*, July 2018, pp. 58-60; p. 68.

31 AEMO, *National Transmission Network Development Plan,* December 2018, p. 27.

32 TransGrid and Powerlink, *Expanding NSW-QLD transmission transfer capacity – Project Assessment Draft Report,* September 2019, p. 5; pp. 31-32.

BOX 2: QNI UPGRADE

TransGrid and Powerlink are considering near-term upgrades to transmission infrastructure around the QNI in order to alleviate congestion and expand transmission transfer capacity between Queensland and New South Wales. In September 2019, TransGrid and Powerlink published a PADR that identified six credible upgrade options. Their preferred option (Option 1A) involves:

- uprating the Liddell to Tamworth lines
- installing dynamic reactive support at Tamworth and Dumaresq
- installing shunt capacitor banks at Tamworth, Armidale and Dumaresq.

TransGrid and Powerlink expect the net market benefits of Option 1A to be $200 million over the period to 2044/45.

TransGrid and Powerlink will also explore medium-term options to increase the capacity of the QNI interconnector as part of a separate RIT-T process.

Source: TransGrid and Powerlink, *Expanding NSW-QLD transmission transfer capacity – Project Assessment Draft Report,* September 2019, pp. 3-5, p.17, p. 33.
Note: The net benefit value listed is in present value terms.

TransGrid and Powerlink's proposals were also detailed in TransGrid's 2019 TAPR.[33] TransGrid and Powerlink estimate that these six options would have capex costs of between $34 million and $461 million,[34] and all of these options are expected to be delivered and have inter-network testing completed by June 2022.[35] The first proposal from TransGrid and Powerlink in the PADR (Option 1A) involves uprating the Liddell to Tamworth lines and installing new dynamic reactive support at Tamworth and Dumaresq, as well as shunt capacitor banks.[36] This option was also discussed in TransGrid's 2019 TAPR.[37] Uprating the Liddell to Tamworth lines would alleviate the QNI #2 constraint, while installing new dynamic reactive support at Tamworth and Dumaresq as well as shunt capacitor banks would alleviate the QNI #3 constraint and the QNI #1 constraint.[38] TransGrid and Powerlink expect Option 1A to increase northward transfer capacity to a maximum of 690 MW and to increase southbound transfer capacity to a maximum of 1,120 MW.[39] Option 1A has an estimated capex cost of $175 million.[40]

33 TransGrid, *New South Wales Transmission Annual Planning Report - 2019*, June 2019, pp. 16-17.

34 All six options are also assumed to have annual operating costs equal to approximately 1 per cent of their capital costs.

35 TransGrid, *New South Wales Transmission Annual Planning Report - 2019*, June 2019, pp. 31-32.

36 TransGrid and Powerlink, *Expanding NSW-QLD transmission transfer capacity – Project Assessment Draft Report,* September 2019, p. 31, p. 33.

37 TransGrid, *New South Wales Transmission Annual Planning Report - 2019*, June 2019, p. 17.

38 Ibid. See also AEMO, *National Transmission Network Development Plan,* December 2018, p. 27.

39 TransGrid and Powerlink, *Expanding NSW-QLD transmission transfer capacity – Project Assessment Draft Report,* September 2019, p. 31.

40 Ibid.

The second proposal from TransGrid and Powerlink (Option 1B) is similar to Option 1A, but only involves uprating the Liddell to Tamworth lines.[41] This option was also discussed in TransGrid's 2019 TAPR.[42] Uprating the Liddell to Tamworth lines would alleviate the QNI #2 constraint.[43] TransGrid and Powerlink expect this option to increase northward transfer capacity to a maximum of 570 MW and to increase southbound transfer capacity to a maximum of 1,070 MW.[44] Option 1B has an estimated capex cost of $34 million.[45]

The third proposal from TransGrid and Powerlink (Option 1C) is similar to Option 1A, but only involves installing new dynamic reactive support at Tamworth and Dumaresq, as well as shunt capacitor banks.[46] This option was also discussed in TransGrid's 2019 TAPR.[47] This proposed option would alleviate the QNI #3 constraint and the QNI #1 constraint.[48] TransGrid and Powerlink expect this option to increase northward transfer capacity to a maximum of 480 MW and to increase southbound transfer capacity to a maximum of 1,120 MW.[49] Option 1C has an estimated capex cost of $142 million.[50]

The fourth proposal from TransGrid and Powerlink (Option 1D) involves cutting the Armidale – Dumaresq 330 kV line into the existing Sapphire Substation, as well as establishing a new mid-point switching station between Bulli Creek – Dumaresq 330 kV.[51] This option was also discussed in TransGrid's 2019 TAPR.[52] This proposed option would alleviate the QNI #3 constraint.[53] TransGrid and Powerlink expect this option to increase northward transfer capacity to a maximum of 480 MW and to increase southbound transfer capacity to a maximum of 1,110 MW.[54] Option 1D has an estimated capex cost of $45 million.[55]

The fifth proposal from TransGrid and Powerlink (Option 5A) involves installing two 40 MW battery energy storage systems (BESSs) that would be connected in both New South Wales and Queensland.[56] This proposed option would alleviate the QNI #1 constraint and the QNI #3 constraint.[57] TransGrid and Powerlink expect this option to increase northward transfer

41 TransGrid and Powerlink, *Expanding NSW-QLD transmission transfer capacity – Project Assessment Draft Report,* September 2019, p. 31, p. 33.

42 TransGrid, *New South Wales Transmission Annual Planning Report - 2019*, June 2019, p. 17.

43 Ibid.

44 TransGrid and Powerlink, *Expanding NSW-QLD transmission transfer capacity – Project Assessment Draft Report,* September 2019, p. 31.

45 Ibid.

46 Ibid, p. 31, p. 34.

47 TransGrid, *New South Wales Transmission Annual Planning Report - 2019*, June 2019, p. 17.

48 Ibid. See also AEMO, *National Transmission Network Development Plan,* December 2018, p. 27.

49 TransGrid and Powerlink, *Expanding NSW-QLD transmission transfer capacity – Project Assessment Draft Report,* September 2019, p. 31.

50 Ibid.

51 TransGrid and Powerlink, *Expanding NSW-QLD transmission transfer capacity – Project Assessment Draft Report,* September 2019, p. 31, p. 34.

52 TransGrid, *New South Wales Transmission Annual Planning Report - 2019*, June 2019, p. 17.

53 Ibid, p. 33.

54 TransGrid and Powerlink, *Expanding NSW-QLD transmission transfer capacity – Project Assessment Draft Report,* September 2019, p. 31.

55 Ibid.

56 TransGrid and Powerlink, *Expanding NSW-QLD transmission transfer capacity – Project Assessment Draft Report,* September 2019, p. 31, pp. 35-36.

57 TransGrid, *New South Wales Transmission Annual Planning Report - 2019*, June 2019, p. 17.

capacity to a maximum of 520 MW and to increase southbound transfer capacity to a maximum of 1,110 MW.[58] Option 5A has an estimated capex cost of $110 million.[59]

The sixth proposal from TransGrid and Powerlink (Option 5B) involves installing a 200 MW BESS that would be connected in both New South Wales and Queensland.[60] This option was also discussed in TransGrid's 2019 TAPR.[61] This proposed option would alleviate the QNI #1 constraint and the QNI #3 constraint.[62] TransGrid and Powerlink expect this option to increase northward transfer capacity to a maximum of 680 MW and to increase southbound transfer capacity to a maximum of 1,270 MW.[63] Option 5B has an estimated capex cost of $461 million.[64]

The TransGrid 2019 TAPR mentions other options for alleviating constraints on QNI that were identified in the earlier QNI *Expanding NSW-QLD transmission transfer capacity* PSCR, including constructing a new single circuit 330 kV transmission line between Liddell and Braemar, constructing new double circuit 330 kV transmission lines and constructing high voltage direct current transmission links.[65] However, these were not assessed as credible options in the TransGrid and Powerlink PADR, which focusses on near-term options for increasing transfer capacity between New South Wales and Queensland.[66] TransGrid and Powerlink indicated that the medium-term options that were discussed in the PSCR will be assessed as part of a separate RIT-T in the future, the timing of which is expected to be informed by the timing of the medium-term option identified as part of 2020 ISP recommendations.[67]

3.3.3 Other projects to assist inter-regional transfers

In addition to the projects listed above, TransGrid has separately proposed two other projects to alleviate constraints on inter-regional transfers involving QNI.

The first project involves installation of a single 330 kV, 120 MVAr shunt capacitor bank at the Armidale substation.[68] TransGrid expects this project to increase voltage stability limits on QNI (presented as QNI #1 in Table 3.1). The project has a total cost of $5.3 million and a planned installation date of March 2021.[69] It was included as a proposal in TransGrid's NCIPAP[70] for the 2018-19 to 2022-23 period.[71]

58 TransGrid and Powerlink, *Expanding NSW-QLD transmission transfer capacity – Project Assessment Draft Report,* September 2019, p. 32.

59 Ibid. These are the assumed upfront capital and reinvestment costs for this option.

60 Ibid, p. 31, p. 36.

61 TransGrid, *New South Wales Transmission Annual Planning Report - 2019*, June 2019, p. 17.

62 TransGrid, *New South Wales Transmission Annual Planning Report - 2019*, June 2019, p. 17.

63 TransGrid and Powerlink, *Expanding NSW-QLD transmission transfer capacity – Project Assessment Draft Report,* September 2019, p. 32.

64 Ibid. These are the assumed upfront capital and reinvestment costs for this option.

65 TransGrid, *New South Wales Transmission Annual Planning Report - 2019*, June 2019, p. 17. See also TransGrid and Powerlink, *Expanding NSW-QLD transmission transfer capacity - Project Specification Consultation Report*, November 2018, p. 5.

66 TransGrid and Powerlink, *Expanding NSW-QLD transmission transfer capacity – Project Assessment Draft Report*, September 2019, p. 3, p. 31.

67 Ibid, p. 17. The PADR stated that this separate RIT-T will include the 'Group 2' option recommended in the 2018 ISP.

68 TransGrid, *New South Wales Transmission Annual Planning Report - 2019*, June 2019, p. 28.

69 Ibid.

The second project involves implementation of a transfer tripping scheme for the Armidale 132 kV capacitor bank.[72] TransGrid expects this project to improve QNI transfer capacity during an outage of an Armidale 330/132 kV transformer. The project has a total cost of approximately $200,000 and a planned installation date of March 2021.[73] The proposal was included in TransGrid's NCIPAP for the 2018-19 to 2022-23 period.[74]

Powerlink did not propose any other projects in its 2019 TAPR to address inter-regional constraints on QNI beyond the projects it is considering as part of the QNI RIT-T process.[75]

3.3.4 Conclusion: QNI

All identified inter-regional constraints associated with QNI are being considered by the relevant TNSP. AEMO identified three expected inter-regional constraints on QNI. TransGrid and Powerlink are proposing six potential augmentation options and TransGrid is proposing a separate option that would alleviate these constraints.

70 This stands for Network capability incentive parameter action plan. See Appendix D for additional information.

71 Australian Energy Regulator (AER), *Final Decision – TransGrid transmission determination 2018 to 2023*, May 2018, p. 15.

72 TransGrid, *New South Wales Transmission Annual Planning Report - 2019*, June 2019, p. 28.

73 Ibid.

74 AER, *Final Decision – TransGrid transmission determination 2018 to 2023*, May 2018, p. 15.

75 Powerlink, *2019 Transmission Annual Planning Report*, June 2019, pp. 65-66.

Table 3.1: **Identified NSW - QLD constraints and proposed solutions - QNI**

RELEVANT AEMO REPORTS	CONSTRAINT DETAILS	PROJECT TO ADDRESS CONSTRAINT	PROJECT STATUS	INDICATIVE PROJECT COST AND TIMING	2018 ISP GROUP 1 PROJECT?
Identified in 2018 NTNDP	QNI #1: Export to Qld from NSW is limited by a voltage collapse limit on loss of the largest generating unit in Queensland	Several PADR options could address this constraint, including: • Uprating the Liddell to Tamworth lines and installing new dynamic reactive support at Tamworth and Dumaresq and shunt capacitor banks (Option 1A) • Installing new dynamic reactive support at Tamworth and Dumaresq and shunt capacitor banks (Option 1C) • Installing two 40 MW BESSs (Option 5A) • Installing two 200 MW BESSs (Option 5B)	Being considered as part of the RIT-T process underway (PADR published)	Indicative cost ranges from $34 million to $461 million and expected completion by June 2022 for PADR projects.	PADR Option 1A and Option 1C involve 2018 ISP Group 1 projects.
		A separate TransGrid project involving installation of a single 330 kV, 120 MVAr shunt capacitor bank at Armidale would also assist with this	The separate shunt capacitor bank at the Armidale is planned for	Indicative cost of $5.3 million and expected completion by March 2021 for the separate shunt capacitor bank project.	

RELEVANT AEMO REPORTS	CONSTRAINT DETAILS	PROJECT TO ADDRESS CONSTRAINT	PROJECT STATUS	INDICATIVE PROJECT COST AND TIMING	2018 ISP GROUP 1 PROJECT?
		constraint.	development by TransGrid.		
Identified in 2018 ISP and 2018 NTNDP	QNI #2: Export to Qld from NSW is limited by the thermal capacity of Liddell - Muswellbrook - Tamworth and Liddell - Tamworth 330 kV lines	Several PADR options could address this constraint, including: • Uprating the Liddell to Tamworth lines and installing new dynamic reactive support at Tamworth and Dumaresq and shunt capacitor banks (Option 1A) • Uprating the Liddell to Tamworth lines (Option 1B)	Being considered as part of the RIT-T process underway (PADR published).	Indicative cost ranges from $34 million to $175 million for PADR projects Expected completion by June 2022.	PADR Option 1A and Option 1B involve 2018 ISP Group 1 projects.
Identified in 2018 ISP and 2018 NTNDP	QNI #3: Export to NSW from Qld is limited by the transient stability limits for a fault on either a Bulli Creek-Dumaresq or Armidale-Dumaresq 330 kV circuit	Several PADR options could address this constraint, including: • Uprating the Liddell to Tamworth lines and installing new dynamic reactive support at Tamworth and Dumaresq and shunt capacitor banks (Option 1A)	Being considered as part of the RIT-T process underway (PADR published).	Indicative cost ranges from $34 million to $461 million for PADR projects Expected completion by June 2022.	PADR Option 1A and Option 1C involve 2018 ISP Group 1 projects.

RELEVANT AEMO REPORTS	CONSTRAINT DETAILS	PROJECT TO ADDRESS CONSTRAINT	PROJECT STATUS	INDICATIVE PROJECT COST AND TIMING	2018 ISP GROUP 1 PROJECT?
		• Installing new dynamic reactive support at Tamworth and Dumaresq and shunt capacitor banks (Option 1C) • Installing two 40 MW BESSs (Option 5A) • Installing two 200 MW BESSs (Option 5B)			

3.3.5 Conclusion: Terranora interconnector

AEMO has not forecast any inter-regional constraints involving the Terranora interconnector in the 2018 ISP or the 2018 NTNDP.

TransGrid and Powerlink did not identify any planned projects in their 2019 TAPRs or in TransGrid and Powerlink's 2019 PADR report that would have an impact on interregional flows involving the Terranora interconnector in either the New South Wales or the Queensland transmission network.[76]

76 TransGrid and Powerlink, *Expanding NSW-QLD transmission transfer capacity – Project Assessment Draft Report,* June 2019.

4 REVIEW OF VICTORIA - NEW SOUTH WALES CONGESTION

> **BOX 3: SUMMARY OF FINDINGS**
>
> All transmission network inter-regional constraints forecast to affect flows between Victoria and New South Wales are being addressed by the relevant TNSPs in their transmission annual planning reports and RIT-T documents. This includes all inter-regional constraints relevant to the Victoria – New South Wales (VNI) interconnector. As such, there is no evidence of insufficient consideration of an inter-regional transmission constraint that would require the Commission to direct a TNSP under its last resort planning powers.

This chapter provides the Commission's analysis of whether there are any constraints impacting the flows between Victoria and New South Wales that are not being addressed by the relevant TNSPs. The chapter:

- Describes VNI, the single interconnector that transports electricity in the NEM between Victoria and New South Wales.
- Reviews TransGrid's 2019 TAPR, AEMO's 2019 Victorian annual planning report (VAPR) and the *Victoria to New South Wales Interconnector Upgrade* PADR regarding projects that address inter-regional constraints affecting VNI.[77]
- Compares the projects that TransGrid and AEMO identify in these reports with AEMO's inter-regional constraint forecasts to identify if there are any 'gaps' where a TNSP has not responded to an expected inter-regional constraint identified by AEMO.

4.1 The Victoria - New South Wales interconnector (VNI)

VNI is an alternating current connection connecting northern Victoria with southern New South Wales. It is defined as the flow across the:[78]

- 330 kV line between Murray and Upper Tumut
- 330 kV line between Murray and Lower Tumut
- 330 kV line between Jindera and Wodonga
- 220 kV line between Buronga and Red Cliffs
- 132 kV bus tie at Guthega (which is normally open).

The 330 kV lines link southern New South Wales with areas in northern Victoria which contain a large amount of hydroelectric generation. As such, they are part of the 'northern corridor' running between Murray (New South Wales) and South Morang (Victoria).[79] The 220

77 AEMO and TransGrid, *Victoria to New South Wales Interconnector Upgrade - Project Assessment Draft Report*, August 2019.

78 AEMO, *Interconnector Capabilities,* November 2017, p. 5.

79 AEMO, *NEM Constraint Report 2016,* June 2017, p. 27.

kV line between Buronga in New South Wales and Red Cliffs in Victoria delivers supply to Victorian load centres such as Bendigo and Ballarat and also transfers power to South Australia via the Murraylink interconnector.[80]

VNI currently has a nominal capacity of:[81]

- 700 - 1,600 MW from Victoria to NSW
- 400 - 1,350 MW from NSW to Victoria.

In addition to VNI upgrades, AEMO and TransGrid are considering the development of an additional KerangLink interconnector that would connect Victoria and New South Wales.

4.2 Expected inter-regional constraints and TNSP proposed projects

4.2.1 Sources considered

This section examines whether all expected inter-regional constraints affecting flows between Victoria and New South Wales are being adequately addressed by the relevant TNSP. It presents the inter-regional constraints that AEMO in its national transmission planning role expects are likely to affect flows between Victoria and New South Wales. The sources used in the analysis are AEMO’s 2018 ISP and 2018 NTNDP.

The section then identifies projects that TransGrid and AEMO in its Victorian TNSP role propose in their 2019 annual planning reports to address these expected inter-regional constraints, as well as the projects proposed in TransGrid and AEMO's Victoria to New South Wales Interconnector Upgrade PADR, which was published in August 2019.

4.2.2 Findings: Victoria – New South Wales interconnector (VNI)

AEMO has identified **eight expected inter-regional constraints** on VNI in the 2018 ISP and the 2018 NTNDP. AEMO and TransGrid's *Victoria to New South Wales Interconnector Upgrade* PADR discusses solutions for five of these constraints, while ways to alleviate the other constraints are discussed in AEMO's 2018 VAPR. Table 4.1 presents each inter-regional constraint identified by AEMO involving VNI and the TNSP projects addressing that constraint.

BOX 4: VNI UPGRADE

AEMO and TransGrid are considering upgrades to transmission infrastructure around the VNI in order to alleviate congestion and increase flows between Victoria and New South Wales. In August 2019, AEMO and TransGrid published a PADR which identified four credible upgrade options. Their preferred option (Option 2) involves:

- Installing a new 500/330 kV transformer at South Morang Terminal Station.

80 Ibid.

81 AEMO, *Interconnector Capabilities*, November 2017, p. 5. The nominal capacity of VNI is highly dependent on the output of Murray generators (for New South Wales to Victoria) and Lower/Upper Tumut generators (for Victoria to New South Wales). VNI can bind in either direction for high demand in New South Wales or Victoria.

- Re-tensioning the 330 kV South Morang - Dederang transmission lines, as well as associated works (including uprating of series capacitors) to allow operation at thermal rating.
- Installing modular power flow controllers on both 330 kV Upper Tumut - Canberra and 330 kV Upper Tumut - Yass lines.

AEMO and TransGrid expect this option to increase export capability from Victoria to New South Wales by approximately 170 MW, and for the net market benefits of this option to be $286 million.

Source: AEMO and TransGrid, *Victoria to New South Wales Interconnector Upgrade - Project Assessment Draft Report*, August 2019, p. 4, pp. 7-8.

The first expected constraint involves exports to New South Wales from Victoria being limited when there is increased generation in Southern New South Wales (shown in Table 4.1 as VNI #1).[82] This corresponds to descriptions of a constraint on the thermal capacity of the 330 kV transmission circuits between the Snowy Mountain area and Sydney in AEMO's 2019 VAPR and TransGrid's 2019 TAPR.[83] Several of the proposals raised by AEMO and TransGrid in their August 2019 PADR would alleviate this constraint. One proposal involves installing modular power flow controllers on both 330 kV Upper Tumut - Canberra and 330 kV Upper Tumut - Yass lines (PADR option 2), which AEMO and TransGrid expect to cost $21 million and have an estimated lead time of 24 months.[84] The other proposal in the PADR that could alleviate this constraint involves bringing forward one component of HumeLink[85] (a new 500 kV line between Snowy and Bannaby), including a connection into the existing 330 kV network (PADR options 3 and 4).[86] AEMO and TransGrid expect this proposal to cost $550 million and have an estimated lead time of 47 months.[87]

The second expected inter-regional constraint involves Victorian exports to New South Wales being limited by the thermal capacity of the Upper Tumut - Canberra 330 kV line (presented as VNI #2 in Table 4.1).[88] Several of the proposals raised by AEMO and TransGrid in their 2019 PADR would alleviate this constraint. One proposal involves a 330 kV Upper Tumut - Canberra line upgrade (PADR option 1), which AEMO and TransGrid expect to cost $38 million and have an estimated lead time of 27 months.[89] Another proposal involves installing modular

82 AEMO, *ISP Appendices,* Appendix D.3.5, July 2018, p. 72. See also AEMO, *National Transmission Network Development Plan*, December 2018, p. 27. See the constraint with the equation ID N>>N-NIL_01N in AEMO, *The National Electricity Market Constraint Report 2018 Electronic Material*, June 2019, Binding Impact tab.

83 AEMO, *Victorian Annual Planning Report,* June 2019, p. 36. See also TransGrid, *New South Wales Transmission Annual Planning Report - 2019*, June 2019, p. 18.

84 AEMO and TransGrid, *Victoria to New South Wales Interconnector Upgrade - Project Assessment Draft Report*, August 2019, p. 6, p. 24. See also TransGrid, *New South Wales Transmission Annual Planning Report - 2019*, June 2019, p. 18.

85 For more details on HumeLink, see AEMO, *Building power system resilience with pumped hydro energy storage*, July 2019, p. 12.

86 AEMO and TransGrid, *Victoria to New South Wales Interconnector Upgrade - Project Assessment Draft Report*, August 2019, p. 6, pp. 25-26. See also TransGrid, *New South Wales Transmission Annual Planning Report - 2019*, June 2019, p. 18.

87 Ibid.

88 AEMO, *ISP Appendices,* Appendix D.3.5, July 2018, p. 72. See also AEMO, *National Transmission Network Development Plan*, December 2018, p. 27. See the constraint with the equation ID N>>V-NIL_O in AEMO, *The National Electricity Market Constraint Report 2018 Electronic Material*, June 2019, Binding Impact tab.

89 AEMO and TransGrid, *Victoria to New South Wales Interconnector Upgrade - Project Assessment Draft Report*, August 2019, p. 6,

power flow controllers on both the 330 kV Upper Tumut - Canberra and 330 kV Upper Tumut - Yass lines (PADR option 2), which AEMO and TransGrid expect to cost $21 million and have an estimated lead time of 24 months.[90] The final proposal that could alleviate this constraint involves bringing forward one component of HumeLink (a new 500 kV line between Snowy and Bannaby), including a connection into the existing 330 kV network (PADR options 3 and 4).[91] AEMO and TransGrid expect this proposal to cost $550 million and have an estimated lead time of 47 months.[92]

The third expected constraint involves exports from New South Wales to Victoria being limited by the thermal capacity of the Dederang - South Morang 330 kV circuits (shown in Table 4.1 as VNI #3).[93] Several of the proposals raised by AEMO and TransGrid in their 2019 PADR would alleviate this constraint. One of these proposals involves re-tensioning the 330 kV South Morang - Dederang transmission lines, as well as associated works to allow operation at an 82°C thermal rating (PADR options 1, 2 and 3). AEMO and TransGrid expect this to cost $21 million and have an estimated lead time of 21 months.[94] Another proposal involves installing a new 330 kV South Morang - Dederang line (PADR option 4). AEMO and TransGrid expect this proposal to cost $415 million and have an estimated lead time of 48 months.[95]

The fourth expected constraint involves Victorian exports to New South Wales being limited by the thermal capacity of the South Morang 500/330 kV transformer (presented as VNI #4 in Table 4.1).[96] Several of the proposals raised by AEMO and TransGrid in their 2019 PADR would alleviate this constraint. One of these proposals involves installation of a single new 500/330 kV transformer at South Morang Terminal Station (PADR options 1, 2 and 3), which AEMO and TransGrid expect to cost $38.5 million and have an estimated lead time of 24 months.[97] Another proposal involves installation of two new 500/330 kV transformers at South Morang Terminal Station (PADR option 4). AEMO and TransGrid expect this option to cost $77 million and have an estimated lead time of 24 months.[98]

The fifth expected constraint involves Victorian exports to New South Wales being limited by a transient stability limit for a two phase to ground fault on a South Morang - Hazelwood 500

---

p. 23. See also TransGrid, *New South Wales Transmission Annual Planning Report - 2019*, June 2019, p. 18.

90 AEMO and TransGrid, *Victoria to New South Wales Interconnector Upgrade - Project Assessment Draft Report*, August 2019, p. 6, p. 24. See also TransGrid, *New South Wales Transmission Annual Planning Report - 2019*, June 2019, p. 18.

91 AEMO and TransGrid, *Victoria to New South Wales Interconnector Upgrade - Project Assessment Draft Report*, August 2019, p. 6, pp. 25-26. See also TransGrid, *New South Wales Transmission Annual Planning Report - 2019*, June 2019, p. 18.

92 Ibid.

93 AEMO, *ISP Appendices,* Appendix D.3.5, July 2018, p. 72. See also AEMO, *National Transmission Network Development Plan*, December 2018, p. 27. See the constraint with the equation ID V>>V_NIL_3 in AEMO, *The National Electricity Market Constraint Report 2018 Electronic Material*, June 2019, Binding Impact tab.

94 AEMO and TransGrid, *Victoria to New South Wales Interconnector Upgrade - Project Assessment Draft Report*, August 2019, p. 6, pp. 23-24. See also AEMO, *Victorian Annual Planning Report*, June 2019, pp. 36-37.

95 AEMO and TransGrid, *Victoria to New South Wales Interconnector Upgrade - Project Assessment Draft Report*, August 2019, p. 6, p. 26. See also AEMO, *Victorian Annual Planning Report*, June 2019, pp. 36-37.

96 AEMO, *ISP Appendices,* Appendix D.3.5, July 2018, p. 72. See also AEMO, *National Transmission Network Development Plan*, December 2018, p. 27. See the constraint with the equation ID V>>V_NIL_2A_R & V>>V_NIL_2B_R & V>>V_NIL_2_P in AEMO, *The National Electricity Market Constraint Report 2018 Electronic Material*, June 2019, Interconnector Binding tab.

97 AEMO and TransGrid, *Victoria to New South Wales Interconnector Upgrade - Project Assessment Draft Report*, August 2019, p. 6, pp. 23-25. See also AEMO, *Victorian Annual Planning Report*, June 2019, pp. 36-37.

98 AEMO and TransGrid, *Victoria to New South Wales Interconnector Upgrade - Project Assessment Draft Report*, August 2019, p. 6, p. 26. See also AEMO, *Victorian Annual Planning Report*, June 2019, pp. 36-37.

kV line (shown in Table 4.1 as VNI #5).[99] This corresponds to descriptions of a Victorian transient stability limitation on transfers to avoid frequency instability in AEMO's 2019 VAPR.[100] To address this constraint, AEMO in its VAPR proposes installing dynamic reactive plant (flexible alternating current transmission systems devices (FACTS) devices) such as Static Var Compensation (SVC), a static synchronous compensator (STACOM), synchronous condensers, and any other equivalents.[101] While AEMO did not provide costs or indicative timings in its 2019 VAPR, AEMO and TransGrid's 2018 Victoria to New South Wales project specification consultation report (PSCR) did provide this information. According to the PSCR, installing an SVC could cost $19 million and have an estimated lead time of 30 months, while a synchronous condenser could cost $20 million and have an estimated lead time of 30 months.[102] Alternatively, AEMO and TransGrid in their 2019 PADR suggest that this constraint would be alleviated by setting up a second South Morang transformer (which is included in all four PADR options)[103] as well as by the preferred options from other RIT-Ts that are currently underway (Victorian Reactive Power Support, Western Victoria Renewable Integration, Project EnergyConnect and HumeLink)[104].

The sixth expected constraint involves New South Wales exports to Victoria being limited by the thermal capacity of the Murray - Dederang 330 kV line (presented as VNI #6 in Table 4.1).[105] AEMO in its 2019 VAPR noted several options that it is considering to help alleviate this constraint, including:[106]

- Implementing an automatic load shedding scheme to allow for operating the lines to a higher thermal rating. The cost of this option depends on contractual arrangements with services providers.
- Installing a third 1,060 MVA 330 kV line between Murray and Dederang with an estimated cost of $186 million (excluding easement costs).
- Installing a second 330 kV line from Dederang to Jindera at an estimated cost of $154 million (excluding easement costs).

The seventh expected constraint involves New South Wales exports to Victoria being limited by the thermal capacity of the Eildon - Thomastown 220 kV line (shown as in Table 4.1 as

99 AEMO, *ISP Appendices,* Appendix D.3.5, July 2018, p. 72. See also AEMO, *National Transmission Network Development Plan*, December 2018, p. 27. See the constraint with the equation ID V>>V_NIL_6A_R in AEMO, *The National Electricity Market Constraint Report 2018 Electronic Material*, June 2019, Interconnector Binding tab.

100 AEMO, *Victorian Annual Planning Report,* June 2019, p. 36. See also AEMO and TransGrid, *Victoria to New South Wales Interconnector Upgrade - Project Assessment Draft Report*, August 2019, p. 44.

101 AEMO, *Victorian Annual Planning Report,* June 2019, p. 37.

102 AEMO and TransGrid, *Victoria to New South Wales Interconnector Upgrade - Regulatory Investment Test for Transmission Project Specification Consultation Report*, November 2018, pp. 9-10.

103 AEMO and TransGrid, *Victoria to New South Wales Interconnector Upgrade* - Project Assessment Draft Report, August 2019, pp. 23-26, p. 44. See VNI #4 for further details on the new transformers proposal in PADR option 4.

104 AEMO and TransGrid, *Victoria to New South Wales Interconnector Upgrade - Project Assessment Draft Report*, August 2019, p. 18, p. 44.

105 AEMO, *ISP Appendices,* Appendix D.3.5, July 2018, p. 72. See also AEMO, *National Transmission Network Development Plan*, December 2018, p. 27. See the constraint with the equation ID V>>V_NIL_1A in AEMO, *The National Electricity Market Constraint Report 2018 Electronic Material*, June 2019, Binding Impact tab.

106 AEMO, *Victorian Annual Planning Report,* June 2019, p. 80. See page 45 for other proposed options.

VNI #7).[107] AEMO in its 2019 VAPR noted several options to help alleviate this constraint, including:[108]

- Installing a wind monitoring scheme.
- Up-rating the Eildon - Thomastown 220 kV line, including terminations to 75°C operation, at an estimated cost of $45.2 million.

The eighth expected constraint identified by AEMO in the 2018 NTNDP involves export and import between Victoria and New South Wales being limited by the thermal capacity of existing transmission lines and voltage transient stability limits (presented as VNI #8 in Table 4.1).[109] This overarching thermal capacity limitation associated with existing transmission lines appears to incorporate constraints VNI #1, 2, 3, 4, 6 and 7. To address voltage stability affecting north Victoria and south New South Wales, AEMO in its 2019 VAPR proposed two options:[110]

- Procuring network support services, including the provision of additional reactive support (generating).
- Installing additional capacitor banks and/or controlled series compensation at Dederang and Wodonga terminal stations.

SnowyLink South (now KerangLink) is another project that AEMO in its role as national transmission planner has proposed to address this constraint in the 2018 NTNDP.[111] This project involves a new interconnector connecting Victoria with New South Wales.

BOX 5: KERANGLINK INTERCONNECTOR

AEMO's 2018 Integrated System Plan (ISP) proposed SnowyLink South (now referred to as KerangLink) and SnowyLink North (now HumeLink).

SnowyLink South proposed an interconnector to connect the Snowy 2.0 project to Melbourne via a central Victorian path. AEMO also considered that net market benefits would support increased interconnection capacity in the southern sections to Victoria from 2035, or earlier if Yallourn Power Station retires. This project is classified as a Group 3 project in the 2018 ISP and would entail:

- 2x 500 kV new circuits between Ballarat and Sydenham
- 2x 500/220 kV transformers at Ballarat
- 2x 500 kV new circuits between Ballarat and Bendigo
- 2x 500 kV new circuits between Kerang and Bendigo

107 AEMO, *ISP Appendices,* Appendix D.3.5, July 2018, p. 72. See also AEMO, *National Transmission Network Development Plan*, December 2018, p. 27. See the constraint with the equation ID V>>V_NIL_1B in AEMO, *The National Electricity Market Constraint Report 2018 Electronic Material*, June 2019, Binding Impact tab.

108 AEMO, *Victorian Annual Planning Report,* June 2019, p. 80. See page 45 for other proposed options.

109 AEMO, *National Transmission Network Development Plan*, December 2018, p. 27.

110 AEMO, *Victorian Annual Planning Report,* June 2019, p. 80. See page 45 for other proposed options.

111 AEMO, *National Transmission Network Development Plan*, December 2018, p. 28. See also AEMO, *Building power system resilience with pumped hydro energy storage*, July 2019, p. 12.

- 2x 500 kV new circuits between Kerang and Darlington Point
- 2x 500/220 kV transformers at Ballarat, Bendigo and Kerang
- A power flow controller on the Bendigo - Shepparton 220 kV line to limit power flow on this line to its maximum thermal capacity (if necessary).
- Power flow controller on the Murray - Dederang and Wodonga - Dederang 330 kV lines to limit power flow on these lines to their maximum thermal capacity (if necessary).

AEMO in the 2018 ISP expected the proposed SnowyLink development to increase the Victoria to New South Wales transfer capability by 2,100 MW towards New South Wales and 1,800 MW towards Victoria. The approximate cost of this proposed interconnector was $2.7 billion.

In July 2019, AEMO published a *Building power system resilience with pumped hydro energy storage* Insights paper which discussed KerangLink. The report stated a KerangLink interconnector would maximise the reliability and resilience benefits from the Snowy 2.0 project at lowest cost for Victorian consumers in time for the next expected closure of brown coal-fired generation in Victoria. AEMO expects that if KerangLink would be delivered by 2030-31, then it would provide net market benefits of approximately $147 million to consumers for the period until 2035. AEMO stated that it intends to commence a formal RIT-T process for this proposed interconnector in the near future.

Source: AEMO, *Integrated System Plan*, July 2018, p. 9. See also AEMO, *ISP Appendices*, July 2018, pp. 61-63, pp. 73-74 and AEMO, *Building power system resilience with pumped hydro energy storage*, July 2019, p. 4, pp. 12-13.
Note: Additional details regarding the individual projects can be found in AEMO, *ISP Appendices*, July 2018, p. 69, p. 74.

4.2.3 Other projects to assist inter-regional transfers

TransGrid proposed two other projects in its 2019 TAPR to alleviate constraints on inter-regional transfers involving VNI.

The first project involves installation of a single 330 kV, 100 MVAr shunt capacitor bank at Wagga.[112] TransGrid expects this project to increase voltage stability limits on VNI (presented as VNI #8 in Table 4.1), thereby lifting the southward transfer limit by 30 MW and the northward transfer limit by 75 MW.[113] The project has a total cost of $4.7 million and a planned installation date of March 2021. The Australian Energy Regulator (AER) approved this project as a proposal in TransGrid's NCIPAP[114] for the 2018-19 to 2022-23 period.[115]

The second project involves installing static synchronous series compensation on the Jindera - Wagga 330 kV line.[116] TransGrid expects this project to improve sharing between three local lines, providing an increase in the southward thermal constraint by 12.8 MW (shown as in

112 TransGrid, *New South Wales Transmission Annual Planning Report - 2019*, June 2019, p. 31. See also AEMO, *Victorian Annual Planning Report*, June 2018, p. 45.

113 TransGrid, *New South Wales Transmission Annual Planning Report - 2019*, June 2019, p. 28

114 This stands for Network capability incentive parameter action plan. See Appendix D for additional information.

115 AER, *Final Decision – TransGrid transmission determination 2018 to 2023*, May 2018, p. 16. The AER's approval was granted for a shunt capacitor bank at Stockdill substation.

116 TransGrid, *New South Wales Transmission Annual Planning Report - 2019*, June 2019, p. 32.

Table 4.1 as VNI constraints #3, 6 and 7) and an increase in the northward voltage constraint by 5.6 MW (presented as VNI #8 in Table 4.1).[117] The project has a total cost of $5.9 million and a planned installation date of June 2023.[118]

AEMO also proposed two projects in its 2019 VAPR as alternative options to alleviate a single constraint on inter-regional transfers involving VNI. The projects AEMO proposed are installing a wind monitoring scheme and up-rating the conductor temperature of both 220 kV circuits between Dederang and Mount Beauty to 82°C, at an estimated cost of $12.6 million.[119] These projects were proposed to alleviate a Dederang – Mount Beauty 220 kV line loading constraint, which was identified as an inter-regional constraint in AEMO's 2019 VAPR but not in the 2018 NTNDP.[120]

AEMO's 2019 VAPR also discussed an AusNet Services project to alleviate constraints on inter-regional transfers involving VNI. This NCIPAP project involves installing a reactive power plant that can dynamically control the impedance of (and thus power flows across) the Jindera – Wodonga 330 kV line.[121] AEMO expects this project to increase the capacity of flows from New South Wales to Victoria by relieving both thermal and voltage constraints in that direction (the VNI constraints #6, 7 and 8).[122] AEMO noted that this project is scheduled to be completed in 2019.

4.2.4 Conclusion: VNI

All identified inter-regional constraints associated with VNI are being considered by the relevant TNSP. AEMO identified eight expected inter-regional constraints on VNI. AEMO and TransGrid are proposing several options to alleviate these constraints on VNI, with many comprising a suite of projects. AusNet Services is also proposing a single project to alleviate constraints on VNI. The expected constraints are addressed by these various options and projects.

117 Ibid.

118 Ibid.

119 AEMO, *Victorian Annual Planning Report*, June 2018, p. 80.

120 The 2018 NTNDP did identify this constraint, but did not suggest that it has inter-regional impacts. For more details, see AEMO, *National Transmission Network Development Plan*, December 2018, p. 27. See also AEMO, *Victorian Annual Planning Report*, June 2018, p. 44. See the constraint with the equation ID V>>V_NIL_5 in AEMO, *The National Electricity Market Constraint Report 2018 Electronic Material*, June 2019, Binding Impact tab.

121 AEMO, *Victorian Annual Planning Report*, June 2018, p. 45.

122 Ibid.

Table 4.1: **Identified VIC - NSW constraints and proposed solutions - VNI**

RELEVANT AEMO REPORTS	CONSTRAINT DETAILS	PROJECT TO ADDRESS CONSTRAINT	PROJECT STATUS	INDICATIVE PROJECT COST AND TIMING	2018 ISP GROUP 1 PROJECT?
Identified in 2018 ISP and 2018 NTNDP	VNI #1: Exports to NSW are Victoria limited when there is increased generation in southern NSW.	Several projects being proposed, including: • installing modular power flow controllers • bringing forward one component of HumeLink.	Being considered as part of the RIT-T process underway (PADR published).	$21 million and a 24 months lead time for the modular power flow controllers $550 million and a 47 months lead time for bringing forward one component of HumeLink.	No
Identified in 2018 ISP and 2018 NTNDP	VNI #2: Export to NSW from VIC is limited by thermal capacity of the Upper Tumut - Canberra 330 kV line.	Several projects being proposed, including: • a 330 kV Upper Tumut - Canberra line upgrade • installing modular power flow controllers • bringing forward one component of HumeLink.	Being considered as part of the RIT-T process underway (PADR published).	$21 million - $550 million depending on the proposal 24 months - 47 months depending on the proposal.	Uprating the South Morang-Dederang lines is a Group 1 project

RELEVANT AEMO REPORTS	CONSTRAINT DETAILS	PROJECT TO ADDRESS CONSTRAINT	PROJECT STATUS	INDICATIVE PROJECT COST AND TIMING	2018 ISP GROUP 1 PROJECT?
Identified in 2018 ISP and 2018 NTNDP	VNI #3: Export to NSW from VIC is limited by the thermal capacity of Dederang - South Morang 330 kV circuits.	Several projects being proposed: • re-tensioning the 330 kV South Morang –Dederang transmission lines • installing a new 330 kV South Morang - Dederang line.	Being considered as part of the RIT-T process underway (PADR published).	$21 million and a 21 months lead time for re-tensioning the lines $415 million and a 48 months lead time installing a new line.	Uprating the Canberra-Upper Tumut line is a Group 1 project
Identified in 2018 ISP and 2018 NTNDP	VNI #4: Export to NSW from VIC is limited by thermal capacity of the South Morang 500/330 kV transformer.	Several projects being proposed: • installation of a single new transformer at South Morang Terminal Station • installation of two new transformers at South Morang Terminal Station.	Being considered as part of the RIT-T process underway (PADR published).	$38.5 million and a 24 months lead time for a single transformer $77 million and a 24 months lead time for two transformers.	An additional new transformer is a Group 1 project
Identified in 2018 ISP and 2018 NTNDP	VNI #5: Export to NSW from VIC is limited by transient stability limit for a two phase to ground fault on a South	AEMO's VAPR proposes several options, including an SVC or synchronous condenser	Being considered by AEMO separately and as part of the RIT-T process underway (PADR	$19 million and a 30 months lead time for an SVC	A braking resistor, battery storage or a FACTS device

RELEVANT AEMO REPORTS	CONSTRAINT DETAILS	PROJECT TO ADDRESS CONSTRAINT	PROJECT STATUS	INDICATIVE PROJECT COST AND TIMING	2018 ISP GROUP 1 PROJECT?
	Morang - Hazelwood 500 kV line.	AEMO and TransGrid's PADR proposes an additional South Morang transformer, as well as proposed options from other on-going RIT-Ts.	published).	$20 million and a 30 months lead time for a synchronous condenser.	are AEMO Group 1 projects
Identified in 2018 ISP and 2018 NTNDP	VNI #6: Export to VIC from NSW is limited by thermal capacity of Murray - Dederang 330 kV line.	Several projects being proposed, including: • an automatic load shedding scheme • a third 1,060 MVA 330 kV line between Murray and Dederang • a second 330 kV line from Dederang to Jindera at an estimated cost of $154 million.	Being considered by AEMO.	$186 million excluding easement costs for the third line $154 million excluding easement costs for the second line.	No
Identified in 2018 ISP and 2018 NTNDP	VNI #7: Export to VIC from NSW is limited by thermal capacity of the Eildon - Thomastown 220 kV line.	Several projects being proposed, including: • installing a wind monitoring scheme. • up-rating the Eildon - Thomastown 220 kV line.	Being considered by AEMO.	$45.2 million for uprating the line.	No
Identified in 2018	VNI #8: Export and import	Several projects being	Being considered by	No costs or lead	No

RELEVANT AEMO REPORTS	CONSTRAINT DETAILS	PROJECT TO ADDRESS CONSTRAINT	PROJECT STATUS	INDICATIVE PROJECT COST AND TIMING	2018 ISP GROUP 1 PROJECT?
NTNDP	between NSW and VIC is limited by thermal capacity of existing transmission lines and voltage transient stability limits.	proposed, including: • Procuring network support services • Install additional capacitor banks and/or controlled series compensation • The KerangLink interconnector.	AEMO.	times provided for these proposals.	

5 REVIEW OF VICTORIA - SOUTH AUSTRALIA CONGESTION

> **BOX 6: SUMMARY OF FINDINGS**
>
> All transmission network inter-regional constraints expected to affect flows between Victoria and South Australia are being addressed by the relevant TNSPs in their transmission annual planning reports and RIT-T documents. This includes all inter-regional constraints relevant to the Heywood and Murraylink interconnectors. As such, there is no evidence of insufficient consideration of an inter-regional transmission constraint that would require the Commission to direct a TNSP under its last resort planning powers.

This chapter provides the Commission's analysis of whether there are any significant inter-regional constraints affecting the flows between Victoria and South Australia that are not being addressed by the relevant TNSPs. The chapter:

- Describes the Heywood and Murraylink interconnectors, the two interconnectors that transport electricity in the NEM between Victoria and South Australia.
- Reviews ElectraNet's 2019 transmission annual planning report, AEMO's VAPR and the *SA Energy Transformation* PACR regarding projects that address inter-regional constraints affecting the Heywood and Murraylink interconnectors.[123]
- Compares the proposed projects that ElectraNet and AEMO identify in these reports with AEMO's expected inter-regional constraints to identify if there are any 'gaps' where a TNSP has not responded to an expected inter-regional constraint identified by AEMO.

5.1 The Heywood interconnector

The Heywood interconnector is an alternating current connection between Heywood in Victoria and the south-east of South Australia.[124] It is defined as the flow across the 275 kV lines between the Heywood substation in Victoria and the South East substation in South Australia.[125]

ElectraNet recently carried out upgrades on the Heywood interconnector to increase the interconnector's nominal transfer capacity to 650 MW in either direction of flow.[126] The limits on the Heywood interconnector currently remain below 650 MW in order to manage system security issues, including a potential stability issue at high levels of transfer from Victoria to South Australia.[127] ElectraNet is working with AEMO to allow the full 650 MW capacity of the

123 ElectraNet, *SA Energy Transformation RIT-T – Project Assessment Conclusions Report,* February 2019.

124 AEMO, *NEM Constraint Report 2016,* June 2017, pp. 28-29.

125 AEMO, *Interconnector Capabilities,* November 2017, p. 6.

126 Ibid.

127 Ibid, p. 6. See also AEMO 2017, Update Inter-Network Testing and Transfer Limit - Heywood Interconnector, viewed 15 October 2018, http://www.aemo.com.au/Market-Notices?currentFilter=&sortOrder=searchString =56893

Heywood interconnector to be released during 2019.[128] As a result, the Heywood interconnector currently has a nominal capacity of:[129]

- 600 MW from Victoria to South Australia
- 500 MW from South Australia to Victoria.

The Heywood interconnector now includes three 500/275 kV transformers at Heywood and connects into South Australia via a double circuit 275 kV line.[130] It also includes a number of connections to the parallel 132 kV network in south-eastern South Australia.[131]

5.2 The Murraylink interconnector

Murraylink is a high voltage direct current (HVDC) link that connects Red Cliff in Victoria to Berri in South Australia.[132] The Murraylink interconnector currently has a nominal capacity of:

- 220 MW from Victoria to South Australia
- 200 MW from South Australia to Victoria.[133]

Murraylink features runback schemes that manage many of the thermal issues in the Riverland of South Australia and western Victoria 220kV.[134]

In addition to the Heywood and Murraylink interconnectors which currently connect Victoria to South Australia, ElectraNet are considering development of a Project EnergyConnect interconnector that would connect South Australia and New South Wales.

5.3 Expected inter-regional constraints and TNSP proposed projects

5.3.1 Sources considered

This section examines whether all expected inter-regional constraints affecting flows between Victoria and South Australia are being adequately addressed by the relevant TNSP.

It presents the inter-regional constraints that AEMO in its national transmission planning role expects to affect Victoria – South Australia flows. The sources used in the analysis are AEMO’s 2018 ISP and 2018 NTNDP.

The section then identifies projects that ElectraNet and AEMO in its Victorian TNSP role propose in their 2019 annual planning reports to address these expected inter-regional constraints, as well as the projects proposed in ElectraNet's *SA Energy Transformation* PACR, which was published in February 2019.

128 ElectraNet, *South Australian Transmission annual planning report*, June 2019, p. 33.

129 AEMO, *Interconnector Capabilities,* November 2017, p. 6.

130 Ibid.

131 Ibid.

132 ElectraNet, *South Australian Transmission annual planning report*, June 2017, p. 104.

133 AEMO, *Interconnector Capabilities*, November 2017, p. 7.

134 Ibid. Special protection schemes detect and respond to contingency events so the power system remains in a satisfactory operating state. A runback scheme is a type of special protection scheme which reduces the flow of electricity in a given network element in a controlled way, in response to a specific event. See AEMO, *Summer operations 2017-18*, November 2017, p. 19.

The chapter also identifies projects that AEMO and ElectraNet propose to assist inter-regional transfers, but which do not directly address constraints identified in AEMO's national transmission planning documents.

The Commission’s analysis for the Heywood interconnector is presented first, followed by analysis of the Murraylink interconnector.

5.3.2 Findings: The Heywood interconnector

AEMO has identified **one expected inter-regional constraint** on the Heywood interconnector in the 2018 ISP and the 2018 NTNDP. Table 5.1 presents the inter-regional constraint identified by AEMO involving the Heywood (and Murraylink) interconnector and the TNSP projects addressing that constraint.

This expected constraint also affects the Murraylink interconnector (presented as Heywood and Murraylink #1 in Table 5.1), and involves inter-regional transfers being limited in both directions by the Heywood and Murraylink interconnectors.[135] This constraint was identified in AEMO's 2018 NTNDP.[136]

ElectraNet has discussed this constraint in its 2019 TAPR as transient instability between South Australia and the rest of the NEM affecting imports and exports for both the Heywood and Murraylink interconnectors, as well as thermal ratings of 132 kV lines between Robertstown and North West Bend affecting Murraylink exports.[137] ElectraNet's proposed solution is a new interconnector between South Australia and New South Wales.[138]

BOX 7: PROJECT ENERGYCONNECT INTERCONNECTOR

ElectraNet recently conducted a RIT-T investigating interconnector options in order to reduce the cost of providing secure and reliability electricity to South Australia in the near term, facilitate the longer-term transition of the national electricity market towards low emission energy sources and allow increased sharing of resources across the regions. In February 2019, ElectraNet published a PACR that discussed their preferred option for a Project EnergyConnect interconnector, which involves:

- an HVDC transmission line between Robertstown in mid-north South Australia and Darlington Point via Buronga
- a high voltage alternating current (HVAC) line between Darlington Point and Wagga Wagga in New South Wales
- a Buronga-Red Cliffs 220 kV line.

ElectraNet estimates the net market benefits of this option to be $900 million. If built, the

135 See constraints involving South Australia in AEMO, *The National Electricity Market Constraint Report 2018 Electronic Material*, June 2019, Binding Impact tab.

136 AEMO, *National Transmission Network Development Plan,* December 2018, p. 28.

137 ElectraNet, *Transmission Annual Planning Report - June 2019*, June 2019, pp. 40-41 and p. 73.

138 Ibid.

interconnector is expected to be in service in the second half of 2023.

Following the conclusion of ElectraNet's application for the *South Australia Energy Transformation* RIT-T, the Australian Energy Regulator (AER) received a written notice from the South Australian Council of Social Service disputing the conclusions made in ElectraNet's PACR. In June 2019, the AER determined that ElectraNet did not need to amend its PACR. As a next step, the AER will shortly determine whether the proposed investment satisfies the broader requirements of the RIT-T. This is required before the AER can make a contingent project determination.

Source: ElectraNet, *SA Energy Transformation RIT-T – Project Assessment Conclusions Report,* February 2019, pp. 3-4, p. 9, p. 12. See also ElectraNet, Transmission Annual Planning Report - June 2019, June 2019, p. 73. See also AEMO, *Building power system resilience with pumped hydro energy storage*, July 2019. See also AER 2019, AER to review ElectraNet's proposed interconnector from SA to NSW, viewed 18 November 2019, https://www.aer.gov.au/communication/aer-to-review-electranets-proposed-interconnector-from-sa-to-nsw. See also AER, *South Australian Energy Transformation - Determination on dispute - application of the regulatory investment test for transmission*, June 2019, p. 7, p. 22.

AEMO did not propose any projects in its 2019 VAPR to address the inter-regional constraint on the Heywood interconnector identified in the 2018 NTNDP.

5.3.3 Other projects to assist inter-regional transfers

ElectraNet has discussed four other projects to alleviate constraints on inter-regional transfers involving the Heywood interconnector in its 2019 TAPR.

The first project involves enhancing a currently-operating Wide Area Protection Scheme to enable both the Heywood interconnector and the Murraylink interconnector to be operated closer to their thermal limits.[139] ElectraNet is considering this project to alleviate the emergence of combined interconnector limits constraining all three interconnectors after the Project EnergyConnect interconnector has been completed.[140] ElectraNet considers that this project could increase combined transfer capacity by up to 650 MW, require 1-2 years lead-time for a RIT-T and 2 years of detailed design and delivery, and cost $5-100 million.[141]

The second project involves applying dynamic line ratings to transmission lines between South East and Tungkillo. ElectraNet suggested that this project would alleviate a constraint caused by thermal ratings of 275 kV lines between Tailem Bend and Heywood affecting Heywood imports and exports.[142] ElectraNet suggests that this constraint already exists, but that it could be exacerbated by a new South Australia to New South Wales interconnector. According to ElectraNet's 2018 TAPR, ElectraNet expected this project to enable increased power transfers to and from Victoria by about 31 MW.[143] This proposed project was in

139 ElectraNet, *Transmission Annual Planning Report - June 2019*, June 2019, pp. 40 and p. 43.

140 Ibid.

141 Ibid.

142 ElectraNet, *Transmission Annual Planning Report - June 2019*, June 2019, pp. 40.

143 ElectraNet, *South Australian transmission annual planning report*, June 2018, p. 96.

ElectraNet's NCIPAP[144] for the 2018-19 to 2022-23 period.[145] ElectraNet noted in its 2019 TAPR that these dynamic line ratings have been in service since March 2019.[146]

The third project proposed by ElectraNet involves connecting the Tailem Bend to Cherry Gardens 275 kV line at Tungkillo and stringing a vacant circuit to create a third Tailem Bend to Tungkillo 275 kV line.[147] ElectraNet proposes this project to alleviate a constraint involving thermal ratings of 275 kV lines between Tailem Bend and Tungkillo, which ElectraNet expects to affect Heywood imports and exports after the full capacity of the Heywood interconnector is released.[148] The planned connection of Tailem Bend to Cherry Gardens 275 kV line at Tungkillo is an NCIPAP project with an estimated cost of less than $5 million.[149] The connection is expected to be in service in January 2020.[150] ElectraNet expects the stringing of a vacant circuit third Tailem Bend to Tungkillo 275 kV line to increase combined transfer capacity by 400-600 MW between the two locations, in turn increasing interconnector capacity in either direction.[151] It would require 1-2 years lead-time for a RIT-T and 2-3 years of detailed design and delivery, and would cost $20-80 million.[152]

The fourth and final project proposed by ElectraNet involves installing an additional 100 Mvar switched capacitor bank at South East.[153] ElectraNet proposes this project to alleviate a constraint involving voltage stability limitations in the South East region and to provide increased availability of the Heywood interconnector's full nominal 650 MW capacity in both directions.[154] ElectraNet suggests that the constraint currently exists and affects both imports and exports on the Heywood interconnector.[155] ElectraNet considers that this planned NCIPAP project would cost less than $5 million and the capacitor bank would be in service by June 2021.[156] ElectraNet has stated that the need for this project would be reviewed if Project EnergyConnect becomes committed.[157]

AEMO did not propose any additional projects in its 2019 VAPR to address inter-regional constraints on the Heywood interconnector.

5.3.4 Conclusion: The Heywood interconnector

The one AEMO-identified inter-regional constraint associated with the Heywood interconnector is being considered by the relevant TNSP. ElectraNet is proposing a new interconnector that would alleviate this constraint.

144 This stands for Network capability incentive parameter action plan. See Appendix D for additional information.
145 ElectraNet, *South Australian transmission annual planning report*, June 2018, p. 96.
146 Ibid, p. 60.
147 Ibid, p. 41, p. 43.
148 Ibid.
149 Ibid, p.79.
150 Ibid.
151 Ibid, p. 43.
152 Ibid.
153 Ibid, p. 41.
154 Ibid, p. 41, p. 71.
155 Ibid.
156 Ibid, p. 79.
157 Ibid, p. 71.

Table 5.1: **Identified VIC - SA constraints and proposed solutions - Heywood and Murraylink**

RELEVANT AEMO REPORTS	CONSTRAINT DETAILS	PROJECT TO ADDRESS CONSTRAINT	PROJECT STATUS	INDICATIVE PROJECT COST AND TIMING	2018 ISP GROUP 1 PROJECT?
Identified in 2018 NTNDP	Heywood and Murraylink #1: Inter-regional transfers are limited in both directions by Heywood and Murraylink interconnectors	A new Project EnergyConnect interconnector between South Australia and New South Wales	The PACR has been lodged with the AER	$1.53 billion Indicative project timing is August 2023	No

5.3.5 Findings: The Murraylink interconnector

AEMO has identified one expected inter-regional constraint on the Murraylink interconnector in the 2018 ISP and the 2018 NTNDP.

As outlined previously, this expected constraint also affects the Heywood interconnector (presented as Heywood and Murraylink #1 in Table 5.1) and involves inter-regional transfers being limited in both directions by Heywood and Murraylink interconnectors.[158]

Further details on this constraint and the project proposed to alleviate it are discussed in section 5.3.2. Table 5.1 presents the inter-regional constraint identified by AEMO involving the Murraylink (and Heywood) interconnector. ElectraNet is proposing a new interconnector that would alleviate this constraint.

5.3.6 Other expected constraints

ElectraNet has proposed three other projects to alleviate constraints on inter-regional transfers involving the Murraylink interconnector in its 2019 TAPR.

The first project involves enhancing a Wide Area Protection Scheme to enable both the Heywood interconnector and the Murraylink interconnector to be operated closer to their thermal limits. Further details on this project and the associated constraint can be found in section 5.3.3.

The second project proposed by ElectraNet involves implementing a control scheme to open the 132 kV lines between Waterloo East and Robertstown.[159] ElectraNet is considering this project to alleviate a constraint involving thermal ratings of 132 kV lines between Waterloo East and Robertstown affecting exports on the Murraylink interconnector.[160] ElectraNet suggests that this constraint already exists, but could be exacerbated by a new South Australia to New South Wales interconnector.[161] In its TAPR, ElectraNet did not provide indicative capacity increases, project costs or timing for this project, instead suggesting that it is one of several possible options for reconfiguring the Mid North 132 kV network.[162]

The third project proposed by ElectraNet involves applying short term overload ratings to the Robertstown 275/132 kV transformers. ElectraNet is considering this project to alleviate a constraint on the thermal ratings of the Robertstown 275/132 kV transformers.[163] ElectraNet suggests that this constraint already exists, but could be exacerbated by a new South Australia to New South Wales interconnector.[164] ElectraNet considers that this planned NCIPAP project would be in service in June 2022 and cost less than $5 million.[165]

158 See constraints involving South Australia in AEMO, *The National Electricity Market Constraint Report 2018 Electronic Material*, June 2019, Binding Impact tab.

159 ElectraNet, *South Australian transmission annual planning report*, June 2018, p. 41.

160 Ibid.

161 Ibid.

162 Ibid, p. 43.

163 Ibid, p. 41.

164 Ibid.

AEMO did not propose any additional projects in its 2019 VAPR to address inter-regional constraints on the Murraylink interconnector.

5.3.7 Conclusion: The Murraylink interconnector

The one AEMO-identified inter-regional constraint associated with the Murraylink interconnector is being considered by the relevant TNSP. ElectraNet is proposing a new interconnector that would alleviate this constraint.

165 Ibid, p. 41 and p. 79.

6 REVIEW OF TASMANIA - VICTORIA CONGESTION

BOX 8: SUMMARY OF FINDINGS

All transmission network inter-regional constraints forecast to affect flows between Victoria and Tasmania are being addressed by the relevant TNSPs in their transmission annual planning reports and RIT-T documents. This includes all inter-regional constraints relevant to the Basslink interconnector. As such, there is no evidence of insufficient consideration of an inter-regional transmission constraint that would require the Commission to direct a TNSP under its last resort planning powers.

This chapter provides the Commission's analysis of whether there are any constraints impacting the flows between Victoria and Tasmania that are not being addressed by the relevant TNSPs. The chapter:

- Describes the Basslink interconnector, the single interconnector that transports electricity in the NEM between Tasmania and Victoria.
- Reviews TasNetworks' 2019 TAPR, AEMO's 2019 VAPR and the *Project Marinus* PSCR regarding projects that address inter-regional constraints affecting the Basslink interconnector.[166]
- Compares the projects that TasNetworks and AEMO identify in these reports with AEMO's inter-regional constraint forecasts to identify if there are any 'gaps' where a TNSP has not responded to an expected inter-regional constraint identified by AEMO.

6.1 The Basslink interconnector

The Basslink interconnector is defined as the flow across the direct current (DC) cable between George Town in Tasmania and Loy Yang in Victoria.[167] While there are no national transmission flow paths in Tasmania, the Basslink interconnector is a national transmission flow path, connecting the Tasmania zone with the LaTrobe Valley zone (in Victoria).[168] Unlike the other DC lines in the NEM, the Basslink interconnector has a frequency controller and is able to transfer frequency control ancillery services (FCAS) between Victoria and Tasmania.

As the Basslink interconnector is a market network service provider (MNSP), RIT-Ts are not required to address an identified investment need on the interconnector. Therefore, if the Commission identified a deficiency in the planning arrangements in regards to the Basslink interconnector, it would not be able to direct the owners of the interconnector to carry out a RIT-T under the LRPP. However, if the identified constraints could be alleviated in the transmission corridors connecting to Basslink, or through the construction of another

166 TasNetworks, *Project Marinus Project Specification Consultation Report - Additional interconnection between Victoria and Tasmania*, July 2018.

167 AEMO, *Interconnector Capabilities,* November 2017, p. 6.

168 TasNetworks, *Annual Planning Report 2018*, June 2018, p. 73.

interconnector, the Commission could direct the TNSP in Victoria, Tasmania or both to undertake a RIT-T.

The Basslink interconnector currently has a nominal capacity of:[169]

- 594 MW from Tasmania to Victoria
- 478 MW from Victoria to Tasmania.

In addition to the Basslink interconnector, TasNetworks is considering development of a Marinus Link interconnector that would also connect Tasmania and Victoria.

6.2 Expected inter-regional constraints and TNSP proposed projects

6.2.1 Sources considered

This section examines whether all expected inter-regional constraints affecting flows between Tasmania and Victoria are being adequately addressed by the relevant TNSP.

It presents the inter-regional constraints that AEMO in its national transmission planner role expects to affect Tasmania – Victoria flows. The sources used in the analysis are AEMO's 2018 ISP and 2018 NTNDP.

The section then identifies projects that TasNetworks and AEMO in its Victorian TNSP role propose in their 2019 annual planning reports to address these expected inter-regional constraints, as well as the projects proposed in TasNetworks' *Project Marinus* PSCR, which was published in July 2018.

The chapter also identifies projects that AEMO and TasNetworks propose to assist inter-regional transfers, but which do not directly address constraints identified in AEMO's national transmission planning documents.

6.2.2 Findings: The Basslink interconnector

AEMO has identified **three expected inter-regional constraints** that would affect flows between Victoria and Tasmania in the 2018 ISP and the 2018 NTNDP. Table 6.1 presents each inter-regional constraint identified by AEMO involving the Basslink interconnector and the TNSP projects addressing that constraint.

The first expected constraint involves transmission limitations on the existing single-circuit Palmerstown to Sheffield 220 kV line (presented as Basslink #1 in Table 6.1).[170] TasNetworks' proposed solution to address this expected constraint involves constructing a new double-circuit Palmerston-Sheffield 220 kV transmission line, which has an indicative cost of $120 million.[171] This project has been approved as a contingent project by the AER as part of

169 AEMO, *Interconnector Capabilities,* November 2017, p. 6.

170 AEMO, *ISP Appendices*, July 2018, p. 72. See also TasNetworks, *Annual Planning Report 2019*, June 2019, p. 54. Also see the constraint with the equation ID T::T_NIL_4 in AEMO, *The National Electricity Market Constraint Report 2018 Electronic Material*, June 2019, Interconnector Binding tab.

171 TasNetworks, *Annual Planning Report 2019*, June 2019, p. 54, p. 61.

TasNetworks' revenue submission for the 2019-24 regulatory period.[172] No indicative project timing was provided for this project.

The second expected inter-regional constraint involves the Tasmanian transmission network experiencing low system inertia and difficulty with voltage control around the George Town area, which can impact Basslink interconnector transfer levels (presented as Basslink #2 in Table 6.1).[173] As an initial step to alleviate this constraint, TasNetworks installed a 40 MVAr 110 kV capacitor bank at George Town Substation in 2018.[174] In addition, TasNetworks proposes to install a ±50 MVAr 110 kV dynamic reactive support (STATCOM) at George Town Substation.[175] TasNetworks expects installing the STATCOM to cost $15.1 million and be operational by June 2022.[176] It notes that this project will be subject to the RIT-T process.[177]

The third expected constraint involves Victoria to Tasmania transfer in both directions being limited by the existing Basslink interconnector (presented as Basslink #3 in Table 6.1).[178] TasNetworks' proposed solution to alleviate this constraint involves constructing a second interconnector between Tasmania and Victoria.[179]

BOX 9: MARINUS LINK INTERCONNECTOR

TasNetworks has been conducting a RIT-T process investigating interconnector options in order to increase interconnection between Victoria and Tasmania. In July 2018, TasNetworks with support from the Australian Renewable Energy Agency (ARENA) published a PSCR that discussed their preferred option for a new Marinus Link interconnector, which could involve:

- Option 1: A 600 MW monopole HVDC link, including associated AC transmission network augmentation and connection assets.
- Option 2: A 1,200 MW bipolar HVDC link, including associated AC transmission network augmentation and connection assets.

TasNetworks' most recent estimates suggest that Option 1 would cost $1.3-1.7 billion and Option 2 would cost $1.9-3.1 billion. TasNetworks with ARENA's support published an Initial Feasibility Report in February 2019 which discusses the technical and economic feasibility of the project. TasNetworks expects to release a PADR in 2019.

Source: TasNetworks, *Project Marinus Project Specification Consultation Report - Additional interconnection between Victoria and Tasmania*, July 2018 and TasNetworks, *Annual Planning Report 2019,* June 2019, p. 57. See also TasNetworks, *Initial Feasibility Report*, February 2019.

172 Australian Energy Regulator, *TasNetworks Transmission and Distribution Determination 2019 to 2024 - Overview*, April 2019, pp. 66-67.

173 AEMO, *ISP Appendices*, July 2018, p. 56. See the constraint with the equation ID T^V_NIL_11 in AEMO, *The National Electricity Market Constraint Report 2018 Electronic Material*, June 2019, Interconnector Binding tab.

174 TasNetworks, *Annual Planning Report 2019,* June 2019, p.57.

175 Ibid.

176 Ibid.

177 Ibid.

178 AEMO, *National Transmission Network Development Plan*, December 2018, p. 28. See the constraint with the equation ID T_V_NIL_BL1 in AEMO, *The National Electricity Market Constraint Report 2018 Electronic Material*, June 2019, Interconnector Binding tab.

179 TasNetworks, *Annual Planning Report 2019,* June 2019, p.55.

AEMO did not propose any additional projects in its 2019 VAPR to address inter-regional constraints affecting flows between Victoria and Tasmania.

6.2.3 Other expected constraints

TasNetworks and AEMO did not propose any additional projects in their 2019 transmission annual planning reports to address inter-regional constraints between Victoria and Tasmania.

6.2.4 Conclusion: The Basslink interconnector

All identified inter-regional constraints that would affect inter-regional flows between Victoria and Tasmania are being considered by the relevant TNSP. AEMO identified three expected inter-regional constraints that could affect these flows. TasNetworks are proposing augmentation options, including a Marinus Link interconnector, to alleviate these constraints.

Table 6.1: **Identified TAS - VIC constraints and proposed solutions - Basslink**

RELEVANT AEMO REPORTS	CONSTRAINT DETAILS	PROJECT TO ADDRESS CONSTRAINT	PROJECT STATUS	INDICATIVE PROJECT COST AND TIMING	2018 ISP GROUP 1 PROJECT?
Identified in 2018 ISP	Basslink #1: Transmission limitations on the existing single-circuit Palmerston to Sheffield line.	Constructing a new double-circuit Palmerston to Sheffield line.	Approved as a contingent project.	$120 million No project timing provided.	No
Identified in 2018 ISP	Basslink #2: Low system inertia and difficulty with voltage control around the George Town area.	Installing a +/-50 MVAr STATCOM.	Will be subject to the RIT-T process.	$15.1 million Indicative project timing is by June 2022.	No
Identified in 2018 NTNDP	Basslink #3: Victoria to Tasmania transfer in both directions is limited by the existing Basslink interconnector.	The Marinus Link interconnector.	Approved by the AER as a contingent project. TasNetworks is considering options as part of the RIT-T process (PACR published).	$1.3-3.1 billion No project timing provided.	No

ABBREVIATIONS

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BESS	Battery energy storage system
Commission	See AEMC
DC	Direct current
ESB	Energy Security Board
FACTS	Flexible alternating current transmission systems
HVAC	High voltage alternating current
HVDC	High voltage direct current
ISP	Integrated System Plan
FCAS	Frequency control ancillary services
LRPP	Last resort planning power
MMS	Market management system
MNSP	Market network service provider
MVAr	Mega volt amps (reactive)
MW	Megawatts
NCIPAP	Network capability incentive parameter action plan
NEL	National Electricity Law
NEM	National electricity market
NEMDE	National electricity market dispatch engine
NER	National Electricity Rules
NTNDP	National Transmission Network Development Plan
QNI	Queensland–New South Wales interconnector
PACR	Project assessment conclusions report
PADR	Project assessment draft report
PSCR	Project specification consultation report
RIT-T	Regulatory investment test for transmission
SVC	Static VAR compensator
STATCOM	Static synchronous compensator
TAPR	Transmission annual planning report
TNSP	Transmission network service provider
VAPR	Victorian annual planning report
VNI	Victoria–New South Wales interconnector

A INTERCONNECTION AND CONSTRAINTS

A.1 Interconnection in the NEM

A.1.1 The importance of inter-regional transfers

The NEM is one of the longest interconnected power systems in the world. Almost 40,000km of transmission lines and associated infrastructure make up the NEM transmission network.

The ability to transfer electricity between the eastern and south-eastern states of Australia is fundamental to the operation of the NEM as an interconnected wholesale electricity market. Interconnection allows electricity to flow across the entire network—geographically connecting Queensland, New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania—and facilitating the NEM as a single market.

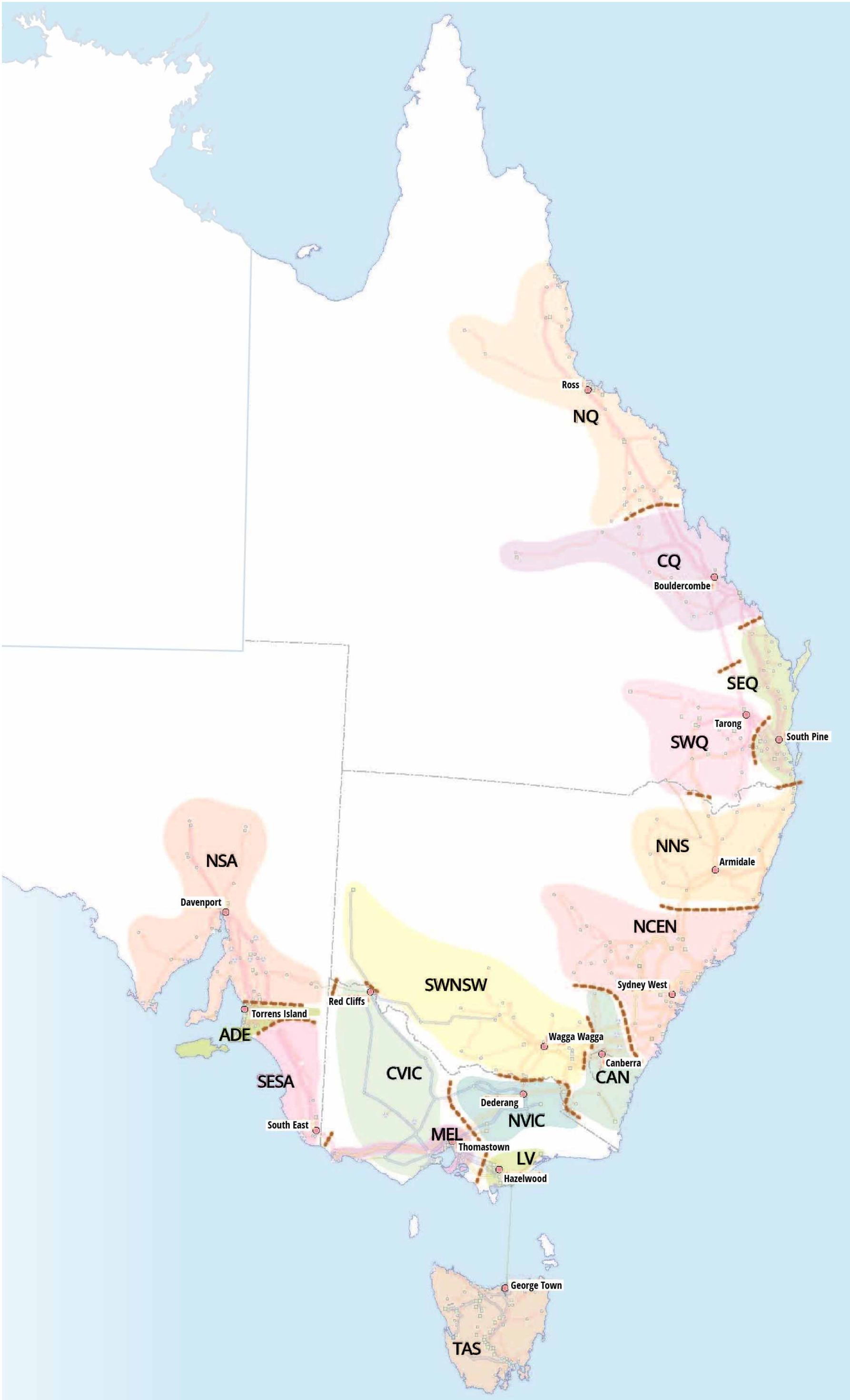
The NEM is divided into five regions which approximately follow the state boundaries: Queensland, New South Wales (including the Australian Capital Territory), Victoria, South Australia and Tasmania. The five interconnected states act as price regions in the NEM. For planning purposes the NEM is further broken up into sixteen national transmission zones, shown in Figure A.1 and Figure A.2. These transmission zones are used for transmission planning and a range of modelling studies.

Figure A.1: National Transmission zones in the NEM

Region	Zones
QLD (Queensland)	NQ (North Queensland)
	CQ (Central Queensland)
	SWQ (South West Queensland)
	SEQ (South East Queensland)
NSW (New South Wales)	NNS (Northern New South Wales)
	NCEN (Central New South Wales)
	CAN (Canberra)
	SWNSW (South West New South Wales)
VIC (Victoria)	LV (Latrobe Valley)
	MEL (Melbourne)
	CVIC (Country Victoria)
	NVIC (Northern Victoria)
SA (South Australia)	ADE (Adelaide)
	NSA (Northern South Australia)
	SESA (South East South Australia)
TAS (Tasmania)	TAS (Tasmania)

Source: AEMO, *Market Modelling and Input Assumptions*, December 2016, pp. 11-12.

Figure A.2: Map of National Transmission zones in the NEM



Source: Based on a chart from AEMO, *Market Modelling and Input Assumptions*, December 2016, pp. 11-12.

Network interconnection has a number of efficiency benefits, which serve the long term interests of consumers. It:

- Can allow electricity in lower priced regions to flow to higher priced regions. This reduces the cost of meeting demand in the NEM and the degree of price separation between regions.
- Can help dampen price volatility within regions.
- Allows investment in generation and transmission to be optimised. Interconnection may defer the need for investment in generation or intra-regional transmission which may otherwise have taken place.

Interconnection also contributes to reliability of supply across the NEM as regions can draw upon a wider pool of electricity supply and demand response.

The growing proportion of generation coming from renewable sources is likely to increase the potential benefits of interconnection. This is because:

- Sources of renewable energy are often geographically further removed from centres of demand than conventional generation.
- There is potential to exploit the geographic diversity of intermittent generation sources, which may lead to more efficient generation siting decisions, and smoothing of the intermittency in aggregate across the NEM.
- The potential for price separation between regions may increase as a result of lower variable-cost renewable energy in some regions.
- The intermittency of some renewable energy sources such as wind and solar (without storage) in some circumstances may require sources of energy or load that can respond to instructions to increase or decrease output or usage to facilitate a reliable power supply.[180] This may be provided by sources located in another region.

However, interconnection also has costs and the above benefits need to be balanced against the costs of increased interconnection. With the exception of the Basslink interconnector between Tasmania and Victoria, all current interconnectors in the NEM are regulated and paid for by consumers through transmission network charges.[181]

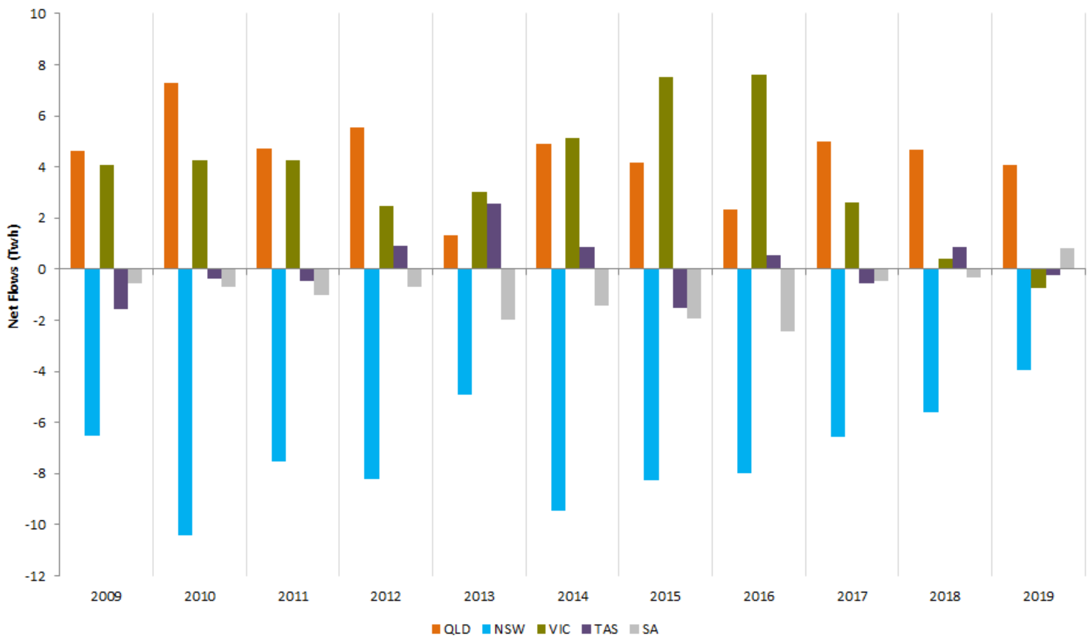
A.1.2 Historical inter-regional flows

Interconnection in the NEM has facilitated inter-regional trade between NEM regions. Depending on local circumstances – such as available generation, the cost of generation and levels of demand – regions are either net importers or net exporters of electricity. Figure A.3 shows inter-regional trade in net flows for each region of the NEM from 2009 - 2019.

180 AEMC, *Reliability frameworks review*, Final report, 26 July 2018, p. 62.

181 See Box 10 for more information on how interconnectors are regulated.

Figure A.3: Net inter-regional flows in the NEM (2009 - 2019)



Source: AEMC analysis of the Market management system (MMS) database.
Note: A positive net flow indicates that the region was exporting electricity in aggregate over the entire year. A negative net flow indicates that the state was importing electricity in aggregate over the entire year.

A.1.3 Interconnectors

In the context of network planning, an 'interconnector' refers to transmission network infrastructure that enables electricity to be carried across NEM regional boundaries. In this sense, interconnectors consist of transmission infrastructure located on each side of a regional boundary, connected by a set of high-voltage transmission lines or cables. Physically, this infrastructure cannot necessarily be distinguished from other parts of the transmission network.

Six interconnectors (often incorporating a number of high voltage transmissions lines) transport electricity between adjacent NEM regions. Table A.1 lists the interconnectors along with their regions, flow path and name. The Queensland - NSW (QNI) interconnector, Victoria - New South Wales (VNI) interconnector and Heywood interconnector are high voltage alternating current (HVAC) links while the Terranora, Murraylink and Basslink interconnectors are HVDC links.

Table A.1: NEM interconnectors and their flow paths

REGION	NAME	FLOW PATH
New South Wales - Queensland	QNI	NNS - SWQ

REGION	NAME	FLOW PATH
New South Wales - Queensland	Terranora (formerly Directlink)	NNS - SEQ
Victoria - New South Wales	VNI (Vic - NSW)	NVIC - SWNSW, CVIC - SWNSW
Victoria - South Australia	Heywood	MEL - SESA
Victoria - South Australia	Murraylink	CVIC - ADE
Tasmania - Victoria	Basslink	LV - TAS

Figure A.4 illustrates where the interconnectors are physically located.

Figure A.4: **Location of interconnectors in the NEM**

Source: AEMO, *An introduction to Australia's National Energy Market*, July 2010, p. 15.

BOX 10: **HOW INTERCONNECTORS ARE REGULATED**

Interconnectors in the NEM are either regulated or market (unregulated).

A regulated interconnector is an interconnector that forms part of a TNSP's regulated asset base as it is used by the TNSP to provide prescribed transmission services to customers. The TNSPs owning the interconnector include the value of the interconnector assets in their regulatory asset base, and their maximum annual revenue set by the AER includes a return on those assets. The revenue is collected by distribution network service providers as part of the network charges levied on retailers. Generally, a TNSP is required to undertake a RIT-T when planning for the building of a new regulated interconnector or increasing the capacity of an existing regulated interconnector.[1]

A market (or unregulated) interconnector derives revenue by trading on the spot market. This is done by purchasing energy in a lower priced region and selling it to a higher priced region, or by selling the rights to revenue traded across the interconnector. New or expanded market interconnectors are not required to undergo the regulatory investment test evaluation. The only market interconnector currently operating in the NEM is the Basslink interconnector, which connects Tasmania and Victoria.

Note: 1 - The RIT-T is discussed in more detail in Appendix B of this report.

A.2 Congestion and inter-regional constraints

A.2.1 Congestion in the transmission network

Limits exist on the transmission network's ability to carry electricity. If the limits on a particular part of the network are reached so that the power flows are constrained to levels less than what an unconstrained efficient dispatch would suggest, then there is said to be congestion on that part of the network.

Congestion on the transmission network has a cost.[182] Congestion generally results in the dispatch of more expensive generation than otherwise would have been the case.[183] The cost of congestion is typically considered in terms of:

- The total time over a fixed period for which flows were constrained to levels below what an efficient dispatch would suggest (eg. hours/year).[184]
- The estimated marginal cost of a constraint on total dispatch costs (marginal value).

Congestion is a normal feature of power systems. It occurs because there are physical limits needed to maintain the power system in a secure operating state. These limits are imposed by:

- Thermal limits, which refer to the heating of a transmission element. The heating of transmission lines, for example, increases as more power is sent across them. This heating may cause the lines to sag closer to the ground, which may encroach on statutory ground clearances. Thermal limits are used for managing the power flow on a transmission element so that it does not exceed a certain rating.

182 In theory, congestion may be eliminated if sufficient money was spent on expanding, or upgrading transmission network infrastructure. However, the cost of doing this may outweigh the costs incurred from the congestion itself. In this sense, congestion occurs not only because of the network's physical limitations, but also because of economic considerations of net costs and benefits. In other words, some level of congestion is likely to be economically efficient. Network congestion also impacts on the ability of NEM participants to manage risks associated with inter-regional trade.

183 Congestion in the network can result in certain sources of generation being 'constrained off' from other parts of the network.

184 Importantly, the amount of time that a constraint equation is binding only provides information regarding how long generator outputs or flows on one or more interconnectors have been constrained. It does not indicate the economic costs of this congestion.

- Stability limits, which include limits to keep generating units operating synchronously and in a stable manner.
- Voltage limits, which involve maintaining voltage magnitudes at acceptable limits.
- Other limits, including those arising from requirements for adequate amounts of frequency control ancillary services (FCAS).

Violating these limits may damage equipment, may lead to supply interruptions and could ultimately be hazardous for the general public.

Allowances must be made to ensure that the transmission elements of the system do not exceed their operational limits, including following credible contingency events.

Importantly, congestion on the transmission network can be influenced by events occurring far away from the physical line that is constrained. Consequently, flows across the interconnectors and the capacity for inter-regional trade in the NEM are not only influenced by the limits of the interconnector(s) capacity itself, but also by constraints occurring in parts of the network further removed from the actual interconnector infrastructure. In this report, congestion anywhere on the transmission network that impacts on the transfer of electricity between regions is called 'inter-regional congestion'.

A.2.2 The dispatch process and constraint equations

To understand how the transmission system is managed in the NEM and how inter-regional congestion may occur, it is useful to describe how transmission limits are managed in the NEM's dispatch optimisation.

The dispatch process determines which generators will be required to generate electricity, and how much they will be required to generate in order to meet demand. This process is managed by AEMO.

AEMO operates the national electricity market dispatch engine (NEMDE), a computer program designed to optimise dispatch decisions. NEMDE dispatches generation on a five-minute interval basis, taking into account a variety of parameters and variables. These include generator offers, system security requirements, and also the thermal, voltage and stability limits of the network. Within these parameters, NEMDE calculates the optimal market solution for dispatch, i.e. the lowest cost solution for dispatch of generation in order to meet demand, allowing for any constraints that may occur on the transmission network as well as system security requirements.

Limitations affecting the network's ability to carry electricity are 'translated' for the purpose of operating NEMDE into constraint equations. Each network constraint equation is a mathematical representation of the way in which different variables affect allowable flows across particular transmission lines. A network constraint is thus a limitation that AEMO imposes on the market dispatch process to account for the physical restrictions necessary for the secure operation of the system.[185]

Terms which occur in constraint equations represent physical attributes such as output from generators, thermal limits of transmission lines, electricity demand in various locations, flows in the network and availability of reactor and capacitor banks. Each constraint equation or set of constraint equations represents a particular type of power system limitation or requirement. Constraint equations can also exist for specific configurations of the power system such as system normal or plant outages.[186]

When economic dispatch is limited, that is where AEMO cannot dispatch the lowest bid priced generation because of network constraints, a constraint is said to be 'binding'.

BOX 11: USE OF CONSTRAINT EQUATIONS BY GENERATORS

In regards to the use of constraint equations by market participants, AEMO highlights that constraint equation formulation is important to scheduled entities such as generators and dispatchable loads because constraint formulation determines the influence or variation in output from that which might be expected from a consideration of offer prices alone.

A generator can be bound by a constraint equation to provide a higher output than it normally would on a commercial basis (called being 'constrained on'). Conversely, a generator may be required to reduce its output due to the action of a constraint equation. If a generator is thus 'constrained off' it may result in a generator selling a lower level of output than they would have otherwise sold.

Source: AEMO, *Constraint Formulation Guidelines,* December 2013, p. 6.

A.2.3 Inter-regional constraints

In simple terms, inter-regional constraints are a sub-set of constraints; they are constraints that can affect the flows between two (or more) regional reference nodes.[187] As discussed previously, interconnector flows are not solely influenced by a few constraints associated with 'pinch points' on interconnectors at regional boundaries. They are a function of numerous limitations across the majority of the physical network. As a result, an inter-regional constraint may be a constraint associated with transmission network infrastructure far from an interconnector.

For the purpose of dispatch and settlement, interconnectors are a notional concept, connecting two regional reference nodes in different regions of the NEM, as illustrated by Figure A.5. In this sense, they are a mathematical representation of the movement of

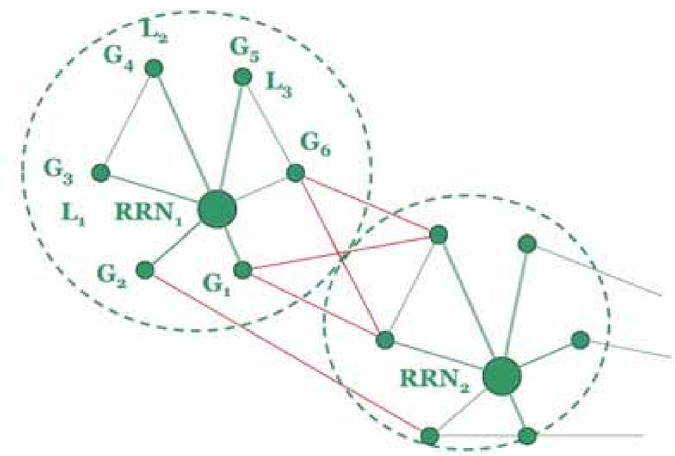
185 AEMO puts it this way: "AEMO determines generation schedules and regional prices in the National Electricity Market using a solver which finds the optimal solution to maximise the value of trade. The solution must satisfy linear constraint equations which are crafted to represent the physical restrictions necessary for secure and sustainable operation." See AEMO, *Constraint Formulation Guidelines*, 5 December 2013, p. 6.

186 For further information see AEMO, *Constraint Implementation Guidelines for the National Electricity Market*, June 2015.

187 Regional reference notes are located at the largest load centre of each region and are used to calculate spot market prices. See Figure A.4 for the locations of the NEM's regional reference nodes.

electricity from one regional reference node to another. That is, the interconnectors represent the transmission flow-paths within each NEM region that link the two regional reference nodes. In terms of NEMDE, an inter-regional constraint is a constraint that contains an inter-connector term in the constraint equation.[188]

Figure A.5: Stylised representation of interconnectors as cross-border infrastructure and additional transmission infrastructure to carry flows to regional reference nodes



Source: AEMO, *Electricity network regulation – AEMO's response to the Productivity Commission issues paper*, 21 May 2012, p. 30 (adapted).

Note: 'RRN' refers to regional reference node, 'G' to generator and 'L' to load (demand) centres. The red lines represent the physical interconnectors connecting the regions.

The NER specifies that before it can exercise the LRPP, the AEMC must "identify a problem relating to constraints in respect of national transmission flow paths *between regional reference nodes* or a potential transmission project".[189] Hence, to conduct the LRRP assessment the Commission examines AEMO's forecasts of those constraints likely to impact the flow of electricity between two regional reference nodes.

A.2.4 Constraint equations as indicators of congestion

Congestion in the network may be identified by observing which constraint equations are binding.[190] Inter-regional congestion can be examined by considering which inter-regional constraints are currently binding, or are expected to bind in the future.

188 A generic constraint is classified as an inter-regional constraint if it includes an interconnector flow term in the constraint's left hand side (LHS). That is, the constraint has a non-zero coefficient for one or more interconnector flow terms in its left hand side.

189 Rule 5.22(g) of the NER, emphasis added. National transmission flow paths are "[t]hat portion of a transmission network or transmission networks used to transport significant amounts of electricity between generation centres and load centres."

190 A constraint equation is binding when the power system flow it manages reach applicable thermal or stability limits, or when a constraint equation is setting an FCAS requirement. When a constraint equation is binding, NEMDE changes the generator and interconnector targets to satisfy the constraint equation. See AEMO, *NEM Constraint Report 2016*, June 2017, p. 12.

There are approximately 11,000 constraint equations used to manage generation and electricity management in the NEM.[191] Approximately 70 per cent of constraints across the transmission network are inter-regional constraints (2014).[192]

Given the interconnectedness of the transmission system, sometimes a constraint may contain multiple interconnector terms. For example, a system normal constraint to avoid overloading the South Morang 500/330 kV (F2) transformer for no contingencies in Victoria appears in the constraint equations for the Heywood, Basslink, Murraylink and VNI interconnectors.[193]

Information about constraints is a key input into the planning process for the transmission network. Network service providers and the RIT-T process assesses the costs and benefits of addressing constraints. Where it is economic to do so, constraints can be addressed by either:

- Augmentations to the transmission infrastructure, called 'network options'.[194] This could include upgrading transmission lines to increase their capacity or installing a new transformer so more power can flow through existing lines.
- Solutions such as demand-side management and network support control ancillary services, which may reduce the strain on transmission infrastructure elements during certain periods, thereby assisting in maintaining operation of this infrastructure within its physical limits.[195] These solutions are termed 'non-network options'.

191 AEMO, *NEM Constraint Report 2016*, June 2017, p. 6. Excluded from these totals are any constraint sets, equations or functions archived before December 2016, and any created by the outage ramping process.

192 AEMC 2015, *Optional Firm Access, Design and Testing*, Final Report - Volume 1, 9 July 2015, p. 71. See also Intelligent Energy Systems, *Assessment of Inter-Regional Congestion*, November 2011, p. 18 (excludes FCAS constraints), when the percentage was approximately 67 per cent. While the number and type of constraint equations has changed since 2014, the proportion remains a valid indication of the interrelated nature of the transmission network.

193 See the constraint with the equation ID V>>V_NIL_2A_R & V>>V_NIL_2B_R & V>>V_NIL_2_P in AEMO, *The National Electricity Market Constraint Report 2018 Electronic Material*, June 2019, Interconnector Binding tab.

194 An augmentation refers to work undertaken to enlarge the system (extension) or to increase its capacity to transmit electricity (upgrade).

195 Network control ancillary services can include generation or automatic load reduction to relieve network overload following a contingency.

B THE COMMISSION'S APPROACH TO THE 2019 LRPP

The LRPP is a power conferred on the Commission in the NER to ensure that sufficient investment is being provided to transport electricity between adjacent regions of the NEM, which is fundamental to the efficient operation of the NEM.

The purpose of the LRPP is to:[196]

> ensure timely and efficient inter-regional transmission investment is being provided for the long term interests of consumers of electricity.

The transmission network in the NEM is critical for facilitating a reliable supply of electricity to consumers. It allows electricity to be bought and sold across Australia’s eastern and south-eastern states.[197]

Under the LRPP if the AEMC identifies that there are no current processes or projects underway to address a constraint that may significantly impact on the efficient operation of the market, then the AEMC has the power to direct one or more network service providers (typically a TNSP) to apply the RIT-T to augmentation project(s) that are likely to relieve that expected constraint.[198] The NER in conjunction with the AER's November 2018 determination on cost thresholds require TNSPs to apply a RIT-T for any projects with an estimated cost of more than $6 million.[199] This applies to both augmentation and replacement expenditure.[200]

Because the LRPP is a power that can be used as a last resort mechanism, to make sure that all significant inter-regional transmission constraints are being addressed in the transmission planning process, the LRPP examines any potential transmission projects that could address expected inter-regional constraints.

Being a last resort mechanism, the LRPP is designed to only be utilised where there is a clear indication that the standard planning processes have resulted in a planning gap regarding the network transmission infrastructure for transporting electricity between NEM regions.

196 Under clause 5.22(b) of the NER.

197 As well as the Australian Capital Territory.

198 Under rules 5.22(h), 5.22(i), and 5.22(k) of the NER.

199 Clause 5.15.3(a)(2) of the NER. See also AER, *Final determination - Cost thresholds review*, November 2018, p. 4.

200 AEMC, *National electricity amendment (replacement expenditure planning arrangement) rule 2017*, Final rule determination, 18 July 2017.

C THE AEMC'S LRPP OBLIGATIONS

The Commission must decide whether, and if so how, to exercise the LRPP in accordance with requirements in the NER and with the LRPP guidelines (guidelines).[201] The obligations pertaining to the LRPP are established in rule 5.22 of the NER and the guidelines. These obligations have directed the Commission's assessment approach in 2019 and in previous years.

C.1 Obligations under the NER

In conducting its assessment of whether there is a need to exercise the LRPP, the NER requires the Commission to consider:[202]

> (1) [any] advice provided by AEMO;
>
> (2) the NTNDP [National Transmission Network Development Plan] for the current and the previous year;
>
> (3) Transmission Annual Planning Reports [TAPRs] published by Transmission Network Service Providers under clause 5.12.2; and
>
> (4) other matters that are relevant in all the circumstances.

The NER also defines a number of criteria related to the exercise of the LRPP. Rule 5.22(g) of the NER specifies that before it can exercise the LRPP, the AEMC must:

> (1) identify a problem relating to constraints in respect of national transmission flow paths between regional reference nodes or a potential transmission project (the problem or the project)
>
> (2) make reasonable inquiries to satisfy itself that there are no current processes underway for the application of the regulatory investment test for transmission in relation to the problem or the project;
>
> (3) consider whether there are other options, strategies or solutions to address the problem or the project, and must be satisfied that all such other options are unlikely to address the problem or the project in a timely manner;
>
> (4) be satisfied that the problem or the project may have a significant impact on the efficient operation of the market; and

201 Rule 5.22 of the NER.

202 Under rule 5.22(f) of the NER. The Commission may request advice from AEMO in relation to the exercise of the last resort planning power, in accordance with the last resort planning power guidelines, rule 5.22(e) of the NER. Appendix D details the information sources analysed for this 2019 LRPP assessment.

(5) be satisfied that but for the AEMC exercising the last resort planning power, the problem or the project is unlikely to be addressed.

The NER defines a national transmission flow path as:

> that portion of a transmission network or transmission networks used to transport significant amounts of electricity between generation and load centres.

Constraints relating to national transmission flow paths between regional reference nodes are termed "inter-regional constraints" in this report.

C.2 Obligations under the guidelines

The Commission also must conduct its assessment of the need to exercise the LRPP in accordance with the guidelines.[203] The guidelines specify processes that must be followed, regarding information provision to the AEMC (by AEMO, network service providers and other parties), consultation and communication.[204]

The guidelines also set out a three-stage LRPP assessment process for undertaking the annual LRPP assessment.[205] Progression from one stage to the next depends on the findings of the preceding stages.

The first stage involves reviewing relevant planning documents to determine whether there are any constraints regarding national transmission flow paths (i.e. inter-regional constraints) that have not been adequately examined by network service providers, i.e. assessing whether there are any potential planning 'gaps'. The guidelines recommend the Commission analyse the following data sources in addition to those sources stipulated by the NER; the 'most recent congestion information resource published by AEMO' and 'any other relevant documents, such as any RIT-T reports'.[206]

The second stage of the Commission's LRPP assessment involves more closely examining the identified gaps to determine whether exercising the LRPP is likely to meet the national electricity objective.[207]

The third stage focuses on who should be directed to undertake a RIT-T.[208] If the Commission decides that exercising the LRPP is necessary, it must provide a direction notice to a TNSP stating the action that the TNSP is required to undertake and the AEMC's reasons for exercising the LRPP. The TNSP must comply with the requirement to carry out a RIT-T.[209]

203 Rule 5.22(d) of the NER. The AEMC publishes and maintains the guidelines. Rules 5.22(o) and 5.22(q) of the NER.

204 The matters to be addressed in the guidelines are set out in rule 5.22(n) of the NER. The guidelines are available at https://www.aemc.gov.au/sites/default/files/2018-02/Last-resort-planning-power-guidelines-FOR-PUBLICATION.pdf

205 AEMC, *Last resort planning power guidelines*, 24 September 2015, p. 2-3.

206 The wording in the Guidelines is that the "AEMC will generally and analyse and compare the following documents…" The requirements in the NER requiring consideration of the two most recent NTNDPs and the transmission annual planning reports would over-ride the guidelines. Ibid, p. 2.

207 Only undertaken if any planning gaps have been identified in stage one.

208 Only undertaken if any planning gaps have been identified in stage one.

209 Rule 5.22(k)(3) of the NER.

Table C.1 summarises the respective roles of market bodies and participants under the current LRPP framework.

Table C.1: LRPP - Current roles of market bodies and market participants under the NER

AEMC	Last resort planner - The AEMC has the LRPP to direct TNSPs to carry out relevant transmission planning if determined to be necessary. The AEMC must refer to information provided on the state of the transmission network by AEMO and the TNSPs, and can request information from both parties in order to determine whether exercising the LRPP is necessary.
AEMO	National transmission planner - AEMO must publish an annual report on the development of the NEM transmission grid as part of its role as the national transmission planner under the National Electricity Law (NEL).[1] This is informed by AEMO's consultation with the TNSPs and provides input to the LRPP regarding congestion on inter-regional flows in the transmission network. Victorian transmission network planner - AEMO also publishes the Victorian Annual Planning Report (VAPR) on the state of the transmission network in Victoria and the projects it plans for the network in its role as the Victorian transmission planner.[2] The VAPR provides input to LRPP considerations regarding projects designed to resolve inter-regional constraints concerning the Victorian transmission network.
TNSPs	Regions' transmission network planners **-** TNSPs publish TAPRs on the state of their transmission network and planned projects for the network. TAPRs provide input to LRPP considerations regarding projects designed to resolve inter-regional constraints concerning various state transmission networks in the NEM.
AER	Economic regulator - The AER administers the RIT-T, which can provide input to LRPP considerations regarding projects designed to resolve inter-regional constraints.

Note: 1 - Under section 49(2) of the NEL and rule 5.20(2) of the NER.
2 - Under rule 5.12 of the NER.

D PLANNING REPORTS CONSIDERED BY THE COMMISSION UNDER THE CURRENT TRANSMISSION PLANNING FRAMEWORK

This chapter outlines the existing planning reports and related documents that the Commission has examined in undertaking the 2019 LRPP review. The draft rules published by the ESB in November 2019 to action the ISP propose some changes to aspects of this framework.

D.1 The NTNDP and the ISP

The NER requires the AEMC to take the NTNDP for the current and previous year into account in deciding whether or not to exercise the LRPP.[210] In addition, the guidelines state that the AEMC has an obligation to use the two most recent NTNDPs.[211]

The relevant NTNDPs for the 2019 LRPP are the 2018 ISP (published in July 2018), which the Commission is taking to serve as the 2017 NTNDP for the purposes of this review, and AEMO's 2018 NTNDP (published in December 2018).

The 2018 ISP includes three types of proposed projects which vary based on the timing of the need, the project scale and the time required to construct the project:[212]

- Group 1 projects require immediate investment in transmission to be undertaken, with completion as soon as practicable
- Group 2 projects require action to be taken now, to initiate work on projects for implementation by the mid-2020s
- Group 3 projects involve enhancing the capability of the grid in the longer term, to the mid-2030s and beyond.

Many of these projects are proposed in order to address constraints that restrict inter-regional flows, and are therefore discussed within this report.

AEMO's 2018 NTNDP updated some of the information contained in the 2018 ISP. The 2018 NTNDP provided assessments of significant binding constraints (including inter-regional constraints) and outlined the status of major proposed transmission infrastructure, such as QNI interconnector upgrades.

D.2 Congestion information resource

The LRPP guidelines require the Commission to consider the most recent congestion information resource published by AEMO in assessing whether to exercise the LRPP.[213] The guidelines state that the Commission must use the most recent congestion resource as a

210 Rule 5.22(f)(2) of the NER.

211 AEMC, *Last Resort Planning Power Guidelines*, September 2015, p. 2.

212 AEMO, *Integrated System Plan*, July 2018, pp. 8-10; p. 80.

213 AEMC, *Last Resort Planning Power Guidelines*, 24 September 2015, p. 2.

major component in its analysis to determine whether there are any inter regional flow constraints in the national electricity market that may not have been examined by TNSPs.[214]

The Commission has considered the National Electricity Market Constraint Report 2018 Electronic Material in conducting this 2019 LRPP assessment.[215]

D.3 Annual planning reports

Each TNSP must publish an annual planning report (APR) by 30 June each year.[216] The APR sets out the outcomes of the annual planning review which a TNSP is required to conduct under the NER.[217] The annual planning review involves a TNSP analysing the expected future operation of its transmission network, taking account of forecast future demand and generation, demand-side and transmission developments and other relevant data.[218] In addition, a TNSP must consider the potential for network augmentations or non-network alternatives to augmentations when conducting an annual planning review.[219] The minimum forward planning period for the annual planning review and therefore covered by the annual planning report is ten years.

These APRs are commonly referred to as 'TAPRs'. AEMO as the Victorian transmission network planner under the NEL publishes a Victorian annual planning report (VAPR), which fulfils the same function as the TAPR for the Victorian transmission network.[220]

TNSPs must take the most recent NTNDP into account when conducting their annual planning review.[221] In particular, when a TNSP proposes augmentations to the network, it must explain in its annual planning report how the proposed transmission augmentations relate to the most recent NTNDP and the development strategies for current or potential national transmission flow paths specified in the NTNDP.

This obligation aligns the planning priorities identified by AEMO in the NTNDP regarding inter-regional flow paths and the planning activities undertaken by TNSPs for each jurisdiction.

As required by the NER and the guidelines, the Commission must consider these annual planning reports when contemplating whether to exercise the LRPP. The NER requires the AEMC to take the TAPRs for the current year into account in deciding whether or not to exercise the LRPP.[222] Correspondingly, the guidelines state that the AEMC has an obligation to use the most recent TAPRs as a major component in its analysis.[223]

The Commission has analysed the following 2019 TAPRs in undertaking this 2019 LRPP review:

214 Ibid, p. 2.
215 AEMO, *The National Electricity Market Constraint Report 2017 Electronic Material*, June 2018.
216 Clause 5.12.2(a) of the NER.
217 Clause 5.12.1(b) of the NER.
218 Clause 5.12.1(a) of the NER.
219 Clause 5.12.1(b)(4) of the NER.
220 Clause 5.12.1 of the NER. See also AEMO, *Victorian Annual Planning Report*, July 2018, p. 8.
221 Clause 5.12.1(b)(3) of the NER.
222 Rule 5.22(f)(2) of the NER.
223 AEMC, *Last Resort Planning Power Guidelines*, 24 September 2015, p. 2.

- The *Victorian Annual Planning Report* published by AEMO.
- The *Transmission Annual Planning Report* published by ElectraNet.
- The *Transmission Annual Report* published by Powerlink.
- The *Annual Planning Report* published by TasNetworks.
- The *New South Wales Transmission Annual Planning Report* published by TransGrid.

D.4 RIT-T documents

D.4.1 RIT-Ts

The NER requires that TNSPs must apply a RIT-T for any projects with an estimated cost of more than $6 million.[224] This requirement covers both augmentation and replacement expenditure.[225]

The purpose of the RIT-T is to identify the transmission investment option that maximises the net economic benefit to all those who produce, consume and transport electricity in the market, after performing a cost-benefit analysis on a number of credible options. The NER define a 'credible option' as an option or group of options that:

- address the identified need
- is, or are, commercially and technically feasible
- can be implemented in sufficient time to meet the identified need.

The costs associated with options for transmission augmentation must be weighed against the benefits they are likely to bring to the market. Investments may be undertaken to either meet reliability standards or to deliver a net market benefit.

The NER also require the RIT-T to consider a number of classes of market benefits that could be delivered by each credible option, such as:

- changes in fuel consumption arising through different patterns of generation dispatch
- changes in the costs for parties, other than the transmission proponent, due to:
    - differences in the timing of new plants
    - differences in capital costs
    - differences in operating and maintenance costs
- changes in network losses
- changes in ancillary service costs
- competition benefits.[226]
- other benefits that are agreed to by the AER.

224 The application of the RIT-T is also subject to a number of exceptions under clause 5.16.3(a) of the NER. The threshold increased to $6 million on 1 January 2016 as a result of a cost thresholds review final determination made by the AER on 5 November 2015.

225 AEMC, *National electricity amendment (replacement expenditure planning arrangement) rule 2017*, Final rule determination, 18 July 2017.

226 Clause 5.16.1(c)(4) of the NER.

D.4.2 LRPP obligations on the AEMC and RIT-Ts considered

The guidelines require the AEMC to consider any relevant RIT-T reports when investigating the possible need to utilise the LRPP.[227] In conducting the 2019 LRPP review, the Commission has examined several RIT-T reports including:

- The *South Australia Energy Transformation* project assessment conclusions report (PACR), published by ElectraNet in February 2019.[228]
- The *Project Marinus* project specification consultation report (PSCR), published by TasNetworks in July 2018.[229]
- The *Expanding NSW-QLD transmission transfer capability* project assessment draft report (PADR), published by Powerlink and TransGrid in September 2019.[230]
- The *Victorian to New South Wales interconnector upgrade* PADR, published by AEMO and TransGrid in August 2019.[231]

D.4.3 Other relevant documents

TNSPs use a Network Capability Incentive Action Plan (NCIPAP) to obtain approval from the AER for certain low cost projects addressing transmission network constraints. Relevant transmission projects addressing inter-regional constraints that are completed via the NCIPAP process have also been considered by the Commission.

The NCIPAP is part of the AER's Service Target Performance Incentive Scheme and provides financial incentives for TNSPs to undertake low cost one-off operational and capital expenditure projects that have broader market benefits. Eligible and completed projects of up to a total of one percent of the proposed maximum allowed revenue for the TNSP per year will receive a pro-rata incentive payment of up to 1.5 per cent of the maximum allowed revenue.[232] During the development of the NCIPAP, the TNSP collaborates with AEMO to identify options and quantify the market benefits of potential NCIPAP projects. TNSPs must then submit their NCIPAP to the AER as a part of their revenue proposals. If the projects are approved by the AER, the TNSP can receive additional revenue for them as part of their upcoming TNSP regulatory period.

227 AEMC, *Last Resort Planning Power Guidelines*, 24 September 2015, p. 2.

228 ElectraNet, *SA Energy Transformation RIT-T Project Assessment Conclusions Report,* February 2019.

229 TasNetworks, *Project Marinus Project Specification Consultation Report - Additional interconnection between Victoria and Tasmania*, July 2018.

230 Powerlink and TransGrid, *Expanding NSW-QLD transmission transfer capacity – Project Assessment Draft Report,* September 2019.

231 AEMO and TransGrid, *Victoria to New South Wales Interconnector Upgrade - Regulatory Investment Test for Transmission Project Assessment Draft Report Report*, November 2018.

232 For further details, see AER, *Final Decision - Electricity transmission network service providers service target performance incentive scheme*, September 2015, p. 7.

E DESCRIPTION OF VARIOUS TECHNOLOGIES USED IN THE TRANSMISSION NETWORK

This section contains a high-level explanation of various terms mentioned in the LRPP 2019 report and how they are used to alleviate congestion on the transmission network.

Table E.1: **Various technologies and how they are used for power systems**

TECHNOLOGY OR CONCEPT	EXPLANATION AND USAGE FOR POWER SYSTEMS
Uprating (a transmission line)	This involves work to increase the thermal rating of a transmission line, meaning more electricity can be transported through the line without exceeding the allowable conductor operating temperature.
Dynamic reactive support (or dynamic reactive compensation)	Devices that provide this can provide variable amounts of reactive power in a few milliseconds to provide reactive power or voltage support. This support can be provided by static VAr compensators (SVCs), Statcoms, synchronous condensers and most types of generators.
Flexible Alternating Current Transmission Systems (FACTS) technology	A number of different types of devices that provide dynamic active and/or reactive power control (including dynamic reactive support) to optimise the use of the network. They may provide an alternative to building new transmission lines.
Capacitors	Capacitors provide a fixed injection of reactive power in the system to a certain level. They can be automatically connected or disconnected as reactive power conditions change in the system.
Shunt (parallel) capacitor banks	This is a type of capacitor that is connected in parallel with a load or a supply point to provide reactive (voltage) support in that location.
Synchronous condensers	These are large rotating machines which, like generators, synchronise with the power

TECHNOLOGY OR CONCEPT	EXPLANATION AND USAGE FOR POWER SYSTEMS
	system frequency. Unlike generators, they are exclusively used to increase the inertia and fault level of the power system, as well as to inject or absorb reactive power.
Static VAR compensator/static VAR compensation (SVC) and Static synchronous compensators (STATCOMs)	A power electronic device that can quickly provide reactive support and voltage control by generating or absorbing reactive power. An SVC usually includes one or more shunt capacitor banks or reactors.
Static synchronous compensators (STATCOMs)	This is similar to an SVC, but can more quickly adjust its generation or absorption of reactive power in response to voltage level changes in the power system.
Series compensation	Series compensation involves connection of capacitors in series with the line conductors. This has the effect of cancelling some of the voltage decreases along the transmission lines, thus increasing the transient stability and voltage stability of the power system.
Cutting (into a line)	Cutting into a single transmission line involves splitting it into two distinct lines, which means if a fault occurs on one of the new lines, then the other line can still be used. Cutting into a line is also used to connect new generators or loads.
transfer tripping scheme	A protection system that sends a command to isolate parts of the transmission network when a fault occurs.
modular power flow controllers	A type of FACT device that can dynamically generate or absorb reactive power.
re-tensioning (transmission power) lines	Transmission power lines naturally sag due to the weight of the conductors. Re-tensioning the conductors reduces the amount that they sag, which can increase the power transfer capacity of the network.
reactive (power) plant	Synchronous condensers, shunt capacitor banks, capacitors, SVCs, and STATCOMs are examples of reactive power plants.
dynamic line ratings	Line ratings determine the maximum safe

TECHNOLOGY OR CONCEPT	EXPLANATION AND USAGE FOR POWER SYSTEMS
	electricity carrying capacities of a power line. Dynamic line ratings use a real time monitoring system to adjust the line rating of a transmission line due to changes in weather conditions. This means they can allow more flows through the line when weather conditions facilitate doing so.