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Appendix A. Renewable Energy Zones

A.1 REZ candidates

AEMO engaged consultants DNV-GL to provide information on the resource quality for potential REZs. Wind resource quality assessment was based on mesoscale wind flow modelling at a height of 150 m above ground level (typical wind turbine height), while Global Horizontal Irradiance (GHI) and Direct Normal Irradiance (DNI) data from the Bureau of Meteorology (BOM) were used to assess solar resource quality. The work undertaken for the ISP is conceptual, and not intended in any way to replace the specific site assessment of potential wind farm sites by developers.

These 10 development criteria were used to identify candidate REZs:

- Wind resource – a measure of high wind speeds (above 6 m/s).
- Solar resource – a measure of high solar irradiation (above 1,600 kW/m^2).
- Demand matching – the degree to which the local resources correlate with demand.
- Electrical network – the distance to the nearest transmission line.
- Cadastral parcel density – an estimate of the average property size.
- Land cover – a measure of the vegetation, waterbodies, and urbanisation of areas.
- Roads – the distance to the nearest road.
- Terrain complexity – a measure of terrain slope.
- Population density – the population within the area.
- Protected areas – exclusion areas where development is restricted.

The following table lists the weighting factors used to identify REZ candidates for detailed assessments. These weighting factors were advised by DNV-GL based on their experience in renewable energy development, and were reviewed by AEMO to ensure areas with active developer interest were highlighted. These criteria weightings were only used for identification of REZs – they were not used to determine the preferred timing or scale of development (see Appendix F.3 for more information).

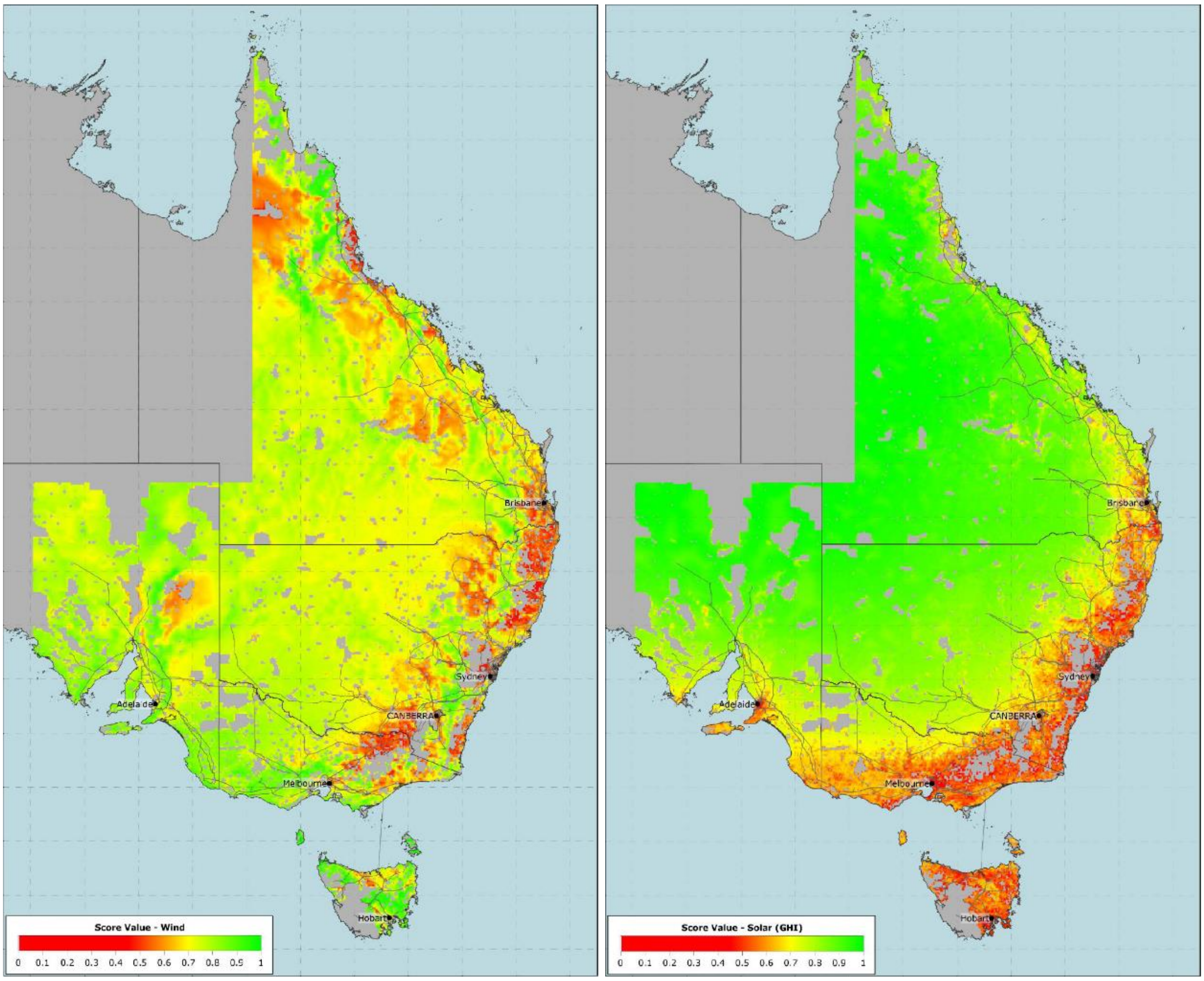
Table 1 REZ criteria weighting

Constraint	Weighting for score	
	Wind	Solar
Wind resource	35%	-
Solar resource	-	30%
Demand matching	5%	-
Electrical network	10%	10%
Cadastral parcel density	10%	10%
Land cover	5%	10%
Roads	5%	5%
Terrain complexity	10%	15%

Constraint	Weighting for score	
	Wind	Solar
Population density	10%	10%
Protected areas	10%	10%

Figure 1 shows the results of this analysis, with the highest rating potential areas for development of wind and solar farms in green.

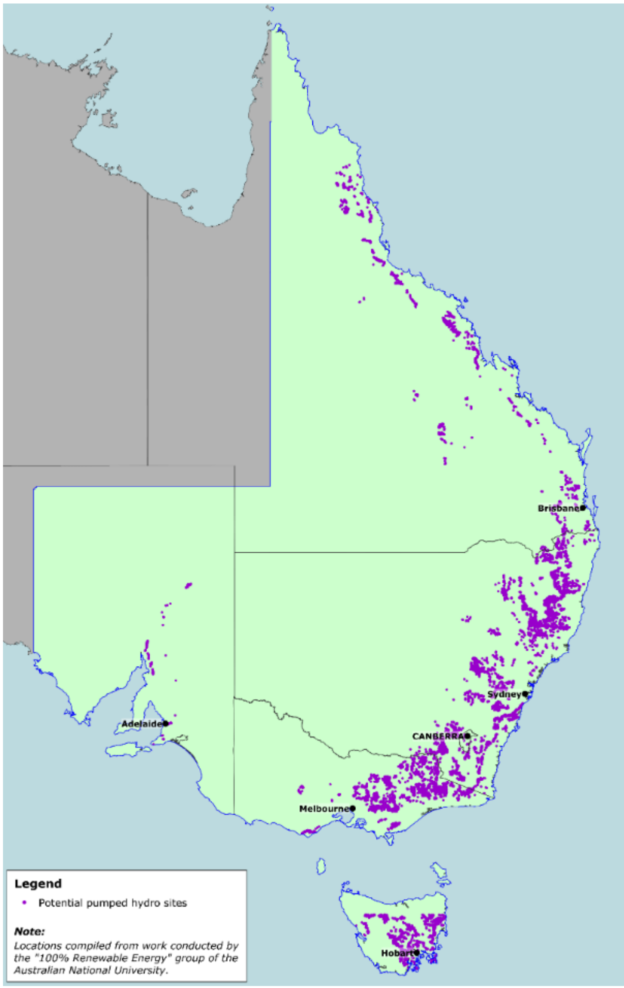
Figure 1 Weighted wind (left) and solar (right) resource areas



In addition to considering high quality solar and wind resource areas, AEMO's REZ candidate identification process considered potential sites for pumped hydro. Figure 2 shows potential sites identified by Australian National University for pumped hydro storage[1].

[1] ANU, 2017, Sites for pumped hydro energy storage, available at http://re100.eng.anu.edu.au/research/phes/.

Figure 2 Identified pumped hydro locations



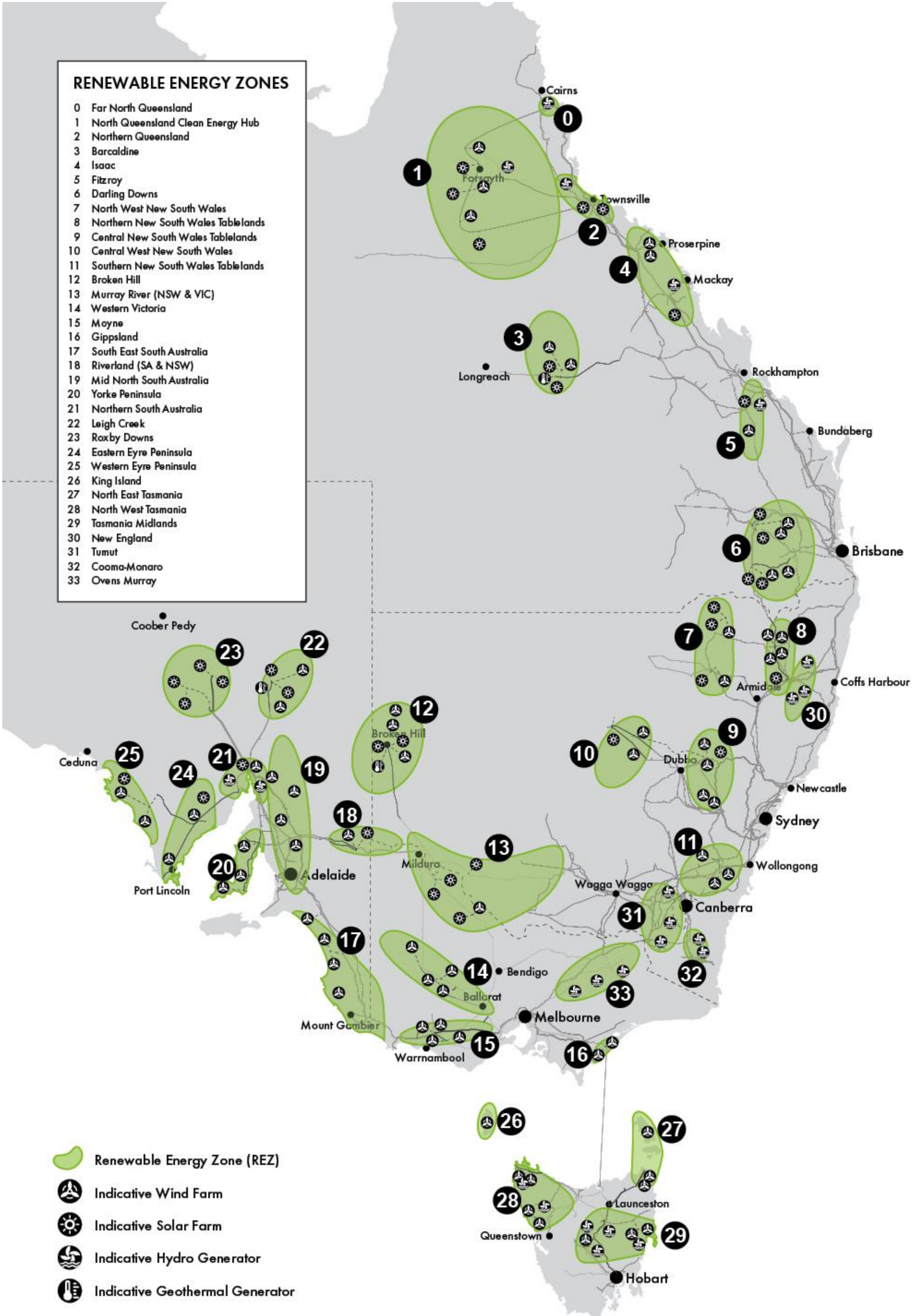
AEMO used this resource information, and industry workshops and public consultation, to identify 34 candidate REZs, shown in Figure 3.

These candidate REZs were published by AEMO in the December 2017 ISP Consultation Paper[2]. Stakeholder feedback largely supported the identified candidate REZs (see the ISP Consultation Summary for more information[3]).

[2] AEMO, *Integrated System Plan Consultation*, December 2017, available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2017/Integrated-System-Plan-Consultation.pdf.

[3] AEMO, *Integrated System Plan Consultation Summary*, available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2017/Integrated-System-Plan-Consultation.pdf.

Figure 3 Renewable Energy Zone candidates

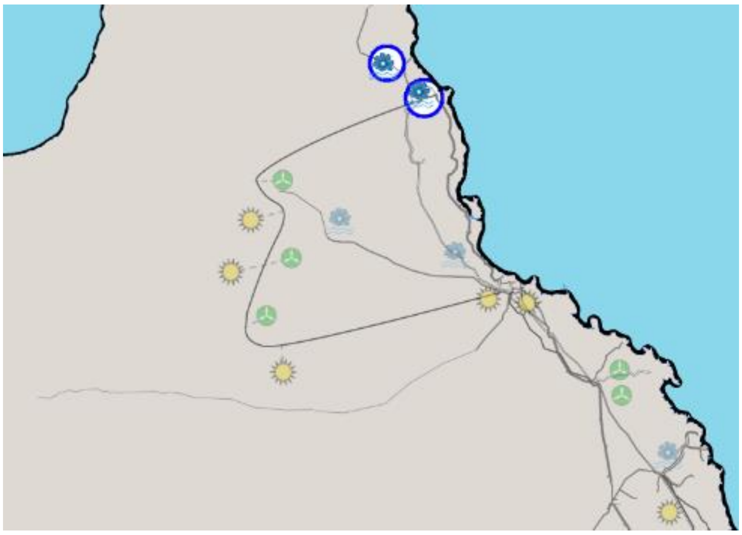


A.2 REZ score cards

This section provides more details on the 34 REZ candidates assessed in the ISP. The following table provides a reference for interpreting the REZ score cards that follow.

<table>
<tr><th colspan="2">REZ Report Card Details</th></tr>
<tr><td>Priority Level</td><td>Based on ISP modelling, indicates areas where generator connections are most likely to proceed over the coming 10 years. A number of factors unknown to AEMO, such as local community support, may affect this priority.
<table>
<tr><td>1</td><td>2</td><td>3</td><td>Low</td></tr>
<tr><td>Immediate priority</td><td>High priority</td><td>Medium priority</td><td>Low priority</td></tr>
</table></td></tr>
<tr><th colspan="2">Renewable Resources</th></tr>
<tr><td>Map Legend</td><td>Indicative generation is shown based on connection interest in the REZ.
<table>
<tr><td>Wind</td><td>Solar</td><td>Hydro</td><td>Geothermal</td></tr>
</table></td></tr>
<tr><td>Resource Quality</td><td>Solar Global Horizontal Irradiance (kw/m²) annual average, median value within REZ
<table>
<tr><td>≥ 2000</td><td>≥ 1900</td><td>≥ 1800</td><td>≥ 1700</td><td>< 1700</td></tr>
<tr><td>A</td><td>B</td><td>C</td><td>D</td><td>E</td></tr>
</table>
Wind Speed (m/s) at 150m from ground level modelled by DNV GL, 10% PoE within REZ.
<table>
<tr><td>≥ 8.4</td><td>≥ 7.2</td><td>≥ 6.6</td><td>≥ 6.0</td><td>< 6.0</td></tr>
<tr><td>A</td><td>B</td><td>C</td><td>D</td><td>E</td></tr>
</table></td></tr>
<tr><td>Potential (MW)</td><td>Estimated potential REZ size (MW) based on the geographical size and resource quality in the REZ.</td></tr>
<tr><td>Diversity</td><td>Diversity describes whether the REZ resources are available at the same time as each of the other REZs or at different times, using a statistical correlation factor. A low correlation gives a better score.
<table>
<tr><td>≤ 0.1</td><td>≤ 0.2</td><td>≤ 0.3</td><td>≤ 0.4</td><td>≤ 0.5</td><td>> 0.5</td></tr>
<tr><td>A</td><td>B</td><td>C</td><td>D</td><td>E</td><td>F</td></tr>
</table>
The diversity of wind resources with other REZs is presented by state. Solar is not charted, because there is not much diversity between REZs.</td></tr>
<tr><td>Demand Matching</td><td>Demand matching describes whether the REZ resources are available at the same time as the regional demand, using a statistical correlation factor. A high correlation gives a better score.
<table>
<tr><td>≥ 0.30</td><td>≥ 0.15</td><td>≥ 0.0</td><td>≥ -0.15</td><td>≥ -0.30</td><td>< -0.30</td></tr>
<tr><td>A</td><td>B</td><td>C</td><td>D</td><td>E</td><td>F</td></tr>
</table></td></tr>
<tr><th colspan="2">Network Limitations</th></tr>
<tr><td>Spare Network Capacity</td><td>The MW value of additional generation that can be transported from the REZ to the required load centre.</td></tr>
<tr><td>Initial Loss Factor</td><td>The average value of the current MLF at connection points inside the REZ.
<table>
<tr><td>≥ 1.00</td><td>≥ 0.95</td><td>≥ 0.90</td><td>≥ 0.85</td><td>≥ 0.80</td><td>< 0.80</td></tr>
<tr><td>A</td><td>B</td><td>C</td><td>D</td><td>E</td><td>F</td></tr>
</table></td></tr>
<tr><td>Loss Factor Robustness</td><td>The sensitivity of MLF to additional generation inside the REZ. The measure used is the additional generation (MW) that can be added before the MLF changes by -0.05.
<table>
<tr><td>≥ 1000</td><td>≥ 750</td><td>≥ 500</td><td>≥ 250</td><td>< 250</td><td>None</td></tr>
<tr><td>A</td><td>B</td><td>C</td><td>D</td><td>E</td><td>F</td></tr>
</table></td></tr>
<tr><th colspan="2">Long-Term Market Simulation Scenarios</th></tr>
<tr><td>Generation Built (MW)</td><td>The maximum generation that is built throughout the 25-year market simulation period. If the generation built exceeds the existing network capacity, then the study has found benefit in augmenting the transmission network to the REZ.</td></tr>
<tr><td>Timing</td><td>The year in which the generation built in the REZ exceeds the existing network capacity.</td></tr>
</table>

Table 2 REZ 0 – Far North QLD

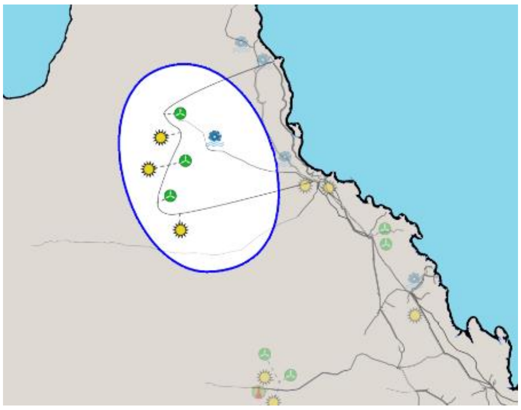
Summary	**REZ Priority Level = Low**
The Far North QLD REZ contains two hydro generators at Barron Gorge and Kareeya, totalling 152 MW capacity. Committed generation projects include Lakeland Solar & Storage (12 MW) and Mt Emerald Wind Farm (180 MW), with several others also proposed. AEMO identified this REZ for pumped hydro generation. Part of pumped hydro genertion in Queensland can be located in this REZ.	

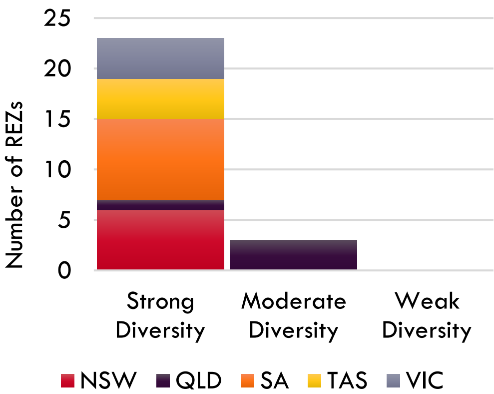
Renewable Resources	**Solar**	**Wind**	**Diversity of Wind with other REZs**
Resource Quality	Not applicable	Not applicable	Not studied
Potential (MW)	Not studied	Not studied	
Diversity	Not studied	Not studied	
Demand Matching Now 2030 2040	Not studied	Not studied	

Network Limitations	**Existing**	**Upgraded**	**Network Description**
Spare Network Capacity (MW)	700	-	The existing 275 kV network has a moderate amount of capacity, but the MLF is likely to decline sharply as new generators are connected because there is not much load in the local area. Far North QLD REZ was identified for potential pumped hydro generation.
Initial Loss Factor	B	-	
Loss Factor Robustness	E	-	

Long-Term Market Simulation Scenarios	**Neutral**	**Neutral with Storage**	**Slow**	**Fast**	**High DER**
Generation built (MW)	A portion of Queensland pumped hydro storage can be located in this REZ				
Timing	-	-	-	-	-

Table 3 REZ 1 – North Qld Clean Energy Hub

Summary	**REZ Priority Level = Low**
The North Qld Clean Energy Hub REZ aligns with the Qld Department of Energy and Water Supply's "Powering North Queensland Plan"[4]. The plan commits $150m funding for network upgrades. There is strong investor interest, with over 2,000 MW proposed wind and solar projects, and the Kidston Pumped Storage Hydro Project (250 MW). On 20 June 2018, the Northern Australia Infrastructure Facility (NAIF) announced a conditional loan of up to $516 million to the Kidston stage 2 project[5]. The project could be connected through the development of a new 275 kV transmission line (approximately 125 km). The development of this new transmission line could consider the future development of this REZ.	

Renewable Resources	**Solar**	**Wind**	**Diversity of Wind with other REZs**
Resource Quality	A	A	
Potential (MW)	4,000	9,275	
Diversity	F	A	
Demand Matching Now 2030 2040	 D F F	 E D C	

Network Limitations	**Existing**	**Upgraded**	**Network Description**
Spare Network Capacity (MW)	0	900	The existing 132 kV line from Ross to Kidston cannot support any large-scale generation developments. A possible investment option is to build a 275 kV circuit from Ross to Kennedy to Kidston to Woree and connect renewable generation along the route. The proposed Kidston stage 2 project could be connected via a new 275 kV transmission line[6].
Initial Loss Factor	D	-	
Loss Factor Robustness	F	E	

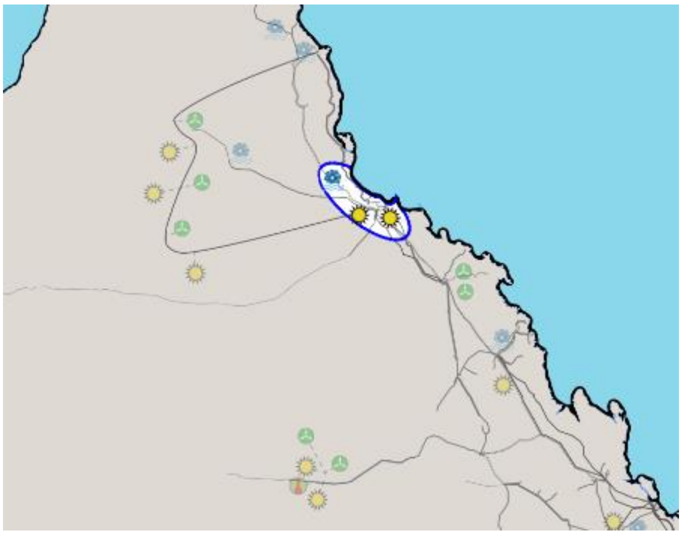
Long-Term Market Simulation Scenarios	**Neutral**	**Neutral with Storage**	**Slow**	**Fast**	**High DER**
Generation Built (MW)	0	0	0	560	0
Timing	-	-	-	2030	-

[4] Queensland Government. https://dnrm.qld.gov.au/data/assets/pdf_file/0003/1253541/Fact-sheet-Powering-North-Queensland-Plan.pdf. Viewed 31 May 2018.

[5] GenexPower. ASX Announcement - NAIF Approves Indicative Term Sheet for up to $516m funding. Available at https://www.asx.com.au/asxpdf/20180620/pdf/43vx02rf6dplpl.pdf.

[6] GenexPower. ASX Announcement - Exclusive Option to Develop New Wind Project at Kidston. Available at https://www.asx.com.au/asxpdf/20180405/pdf/43sz9bp9k2fmjw.pdf.

Table 4 REZ 2 – North QLD

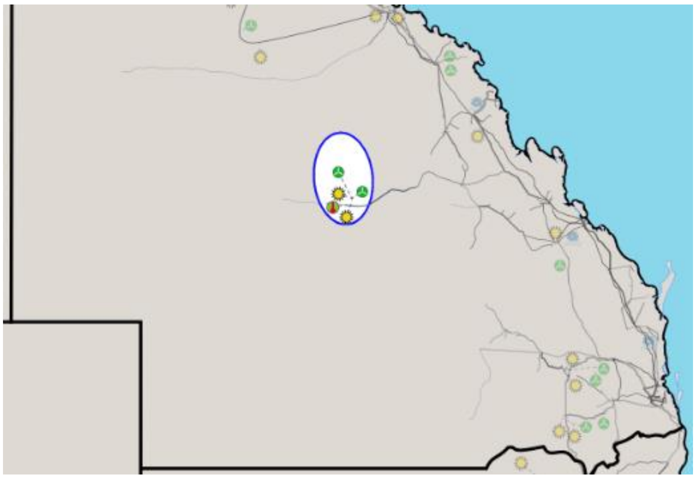
Summary	**REZ Priority Level = Low**
The North QLD REZ includes Townsville and the surrounding area. It has good quality solar and wind resources and is close to the 275 kV backbone. Committed generation projects include Clare Solar Farm (150 MW), Ross River Solar Farm (116 MW), and Sun Metals Solar Farm (125 MW).	

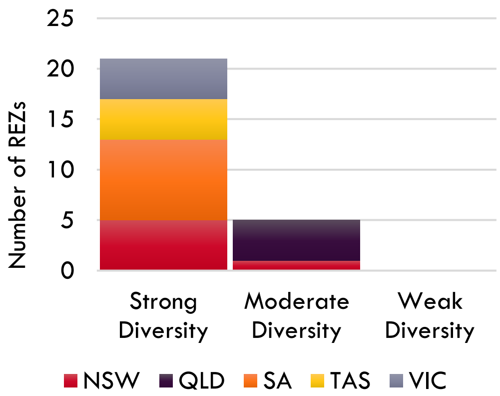
Renewable Resources	**Solar**	**Wind**	**Diversity of Wind with other REZs**
Resource Quality	B	B	Not studied
Potential (MW)	2,500	0	
Diversity	F	Not studied	
Demand Matching Now 2030 2040	 D F F	Not studied	

Network Limitations	**Existing**	**Upgraded**	**Network Description**
Spare Network Capacity (MW)	2,000	-	The existing 275 kV network has good capacity, but this is shared with the REZs in North and Central Queensland. Even though there is good network capacity, the MLF will decline sharply due to the distance from major load centres. The potential for pumped hydro generation has been identified in North QLD REZ. Storing excess solar generation in pumped hydro would relieve network thermal capacity between NQ and CQ.
Initial Loss Factor	B	-	
Loss Factor Robustness	D	-	

Long-Term Market Simulation Scenarios	**Neutral**	**Neutral with Storage**	**Slow**	**Fast**	**High DER**
Generation Built (MW)	1,750	1,750	0	1,750	1,200
Timing	>2040	>2040	-	>2040	>2040

Table 5 REZ 3 – Barcaldine

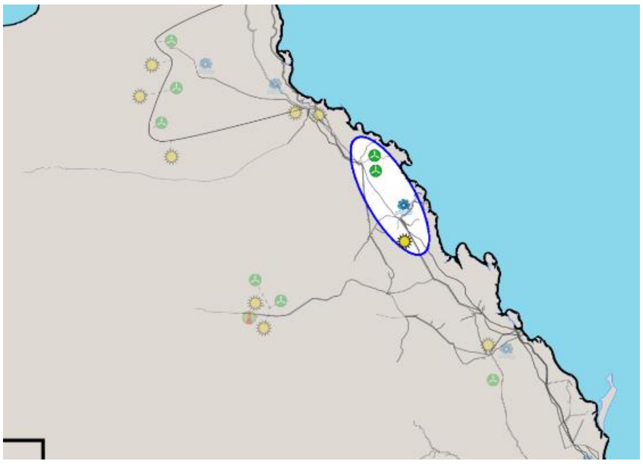
Summary	**REZ Priority Level = Low**
The Barcaldine REZ is in Central Queensland. This REZ has excellent solar resources, good wind resources, and a number of connection enquiries received by Powerlink. There are around 200 MW of committed solar projects with an additional 400 MW proposed. The existing network is very weak and significant upgrades must take place before this level of new generation can connect.	

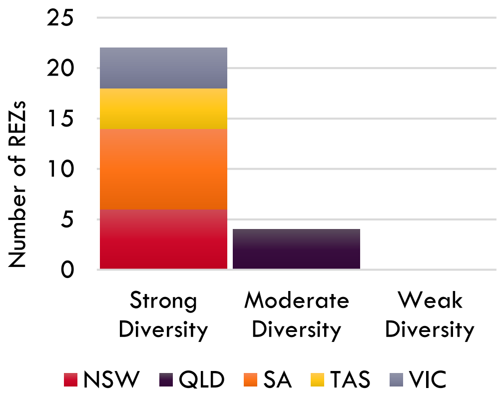
Renewable Resources	**Solar**	**Wind**	**Diversity of Wind with other REZs**
Resource Quality	A	B	
Potential (MW)	4,000	1,910	
Diversity	F	B	
Demand Matching Now 2030 2040	 D F F	 F D B	

Network Limitations	**Existing**	**Upgraded**	**Network Description**
Spare Network Capacity (MW)	0	900	The existing 132 kV line to Barcaldine cannot support any large-scale generation developments. A possible investment option is to build a double circuit 275 kV line from the main backbone at Lilyvale extending inland to Barcaldine. Even after this upgrade, the MLFs will decline sharply because the generation is located a significant distance from load.
Initial Loss Factor	C	C	
Loss Factor Robustness	F	D	

Long-Term Market Simulation Scenarios	**Neutral**	**Neutral with Storage**	**Slow**	**Fast**	**High DER**
Generation Built (MW)	0	0	0	0	0
Timing	-	-	-	-	-

Table 6 REZ 4 – Isaac

Summary	REZ Priority Level = 3
The Isaac REZ covers Collinsville and Mackay. It has high quality solar and wind resources. There are many committed solar projects and many more proposed, totalling over 1,000 MW. The Queensland Government has also proposed funding to upgrade Burdekin Falls Dam and develop hydro power generaton (50 MW)[7].	

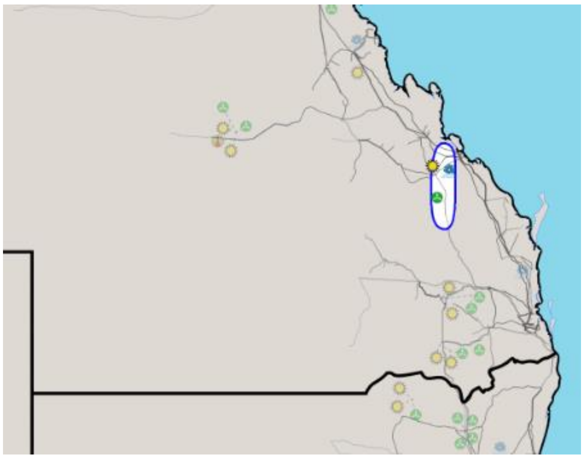
Renewable Resources	Solar	Wind	Diversity of Wind with other REZs
Resource Quality	B	B	
Potential (MW)	3,500	1,860	
Diversity	F	A	
Demand Matching Now 2030 2040	 D F F	 C C B	

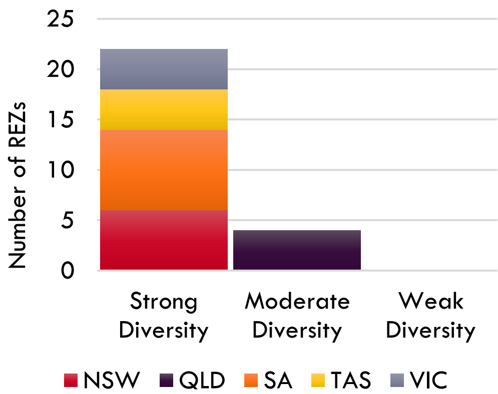
Network Limitations	Existing	Upgraded	Network Description
Spare Network Capacity (MW)	2,000	-	275 kV and 132 kV circuits pass through this REZ. The amount of additional generation is limited by the transfer capacity from North Queensland to Central Queensland to South Queensland. The existing network can accommodate additional generation of approximately 2,800 MW from REZs in North Queensland. The potential for pumped hydro generation was identified in Isaac QLD REZ. Storing excess solar generation in pumped hydro would relieve network thermal capacity between North Queensland and Central Queensland.
Initial Loss Factor	B	-	
Loss Factor Robustness	B	-	

Long-Term Market Simulation Scenarios	Neutral	Neutral with Storage	Slow	Fast	High DER
Generation Built (MW)	1,650	1,420	465	2,800	465
Timing	>2040	>2040	>2040	>2040	>2040

[7] Queensland Government. https://www.dews.qld.gov.au/data/assets/pdf_file/0011/1253828/powering-north-qld-plan.pdf. Viewed 31 May 2018.

Table 7 REZ 5 – Fitzroy

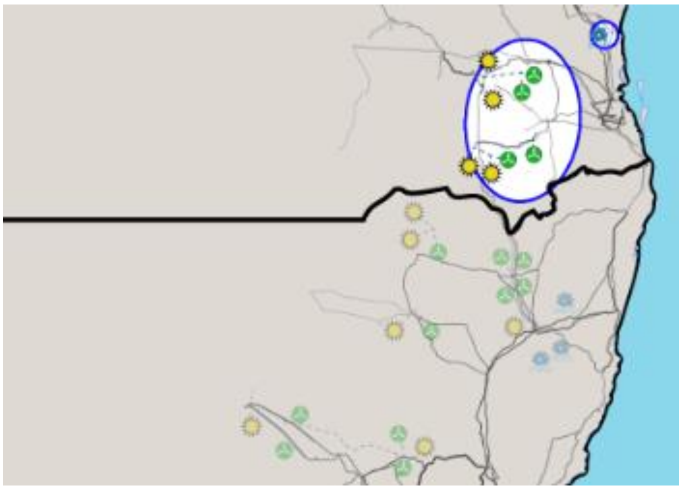
Summary	REZ Priority Level = 2
The Fitzroy REZ covers a strong part of the network where Gladstone and Callide generators are connected. The quality of wind is good and solar is moderate. There is 850 MW of proposed large-scale solar generation.	

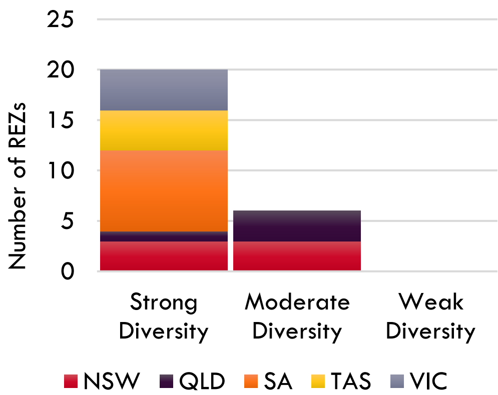
Renewable Resources	Solar	Wind	Diversity of Wind with other REZs
Resource Quality	C	B	
Potential (MW)	2,000	890	
Diversity	F	A	
Demand Matching Now 2030 2040	 D F F	 D B A	

Network Limitations	Existing	Upgraded	Network Description
Spare Network Capacity (MW)	2,000	-	The existing 275 kV network is strong and has good access to load centres in central and southern Queensland. The amount of additional new generation at Fitzroy depends on amount of new generation in other REZs in North and Central Queensland. Around 3,000 MW of combined additional generation can be accommodated from all the REZs in North and Central Queensland. The MLFs in Fitzroy REZ are more sensitive to change than the Darling Downs REZ, but they are robust compared to other REZs in Queensland. Long-term modelling identified more than 1,600 MW coal generation retirement in Central Queensland zone from 2030. This would allow the Fitzroy REZ to accommodate additional generation.
Initial Loss Factor	C	-	
Loss Factor Robustness	A	-	

Long-Term Market Simulation Scenarios	Neutral	Neutral with Storage	Slow	Fast	High DER
Generation Built (MW)	2,220	2,220	0	2,220	2,220
Timing	>2040	>2040	-	>2040	>2040

Table 8 REZ 6 – Darling Downs

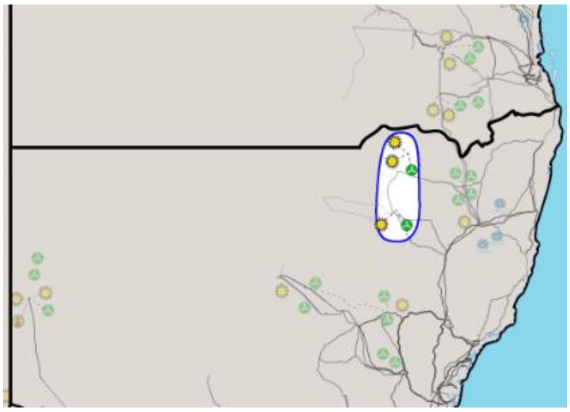
Summary	**REZ Priority Level = 1**
The Darling Downs REZ covers a wide area of South-West Queensland (SWQ). The quality of wind is good and solar is moderate, and there is also the potential for pumped hydro at some sites. The REZ currently includes large amounts of coal-fired and gas powered generation. There is a high level of investor interest in renewables, with over 2,500 MW of solar generation proposed.	

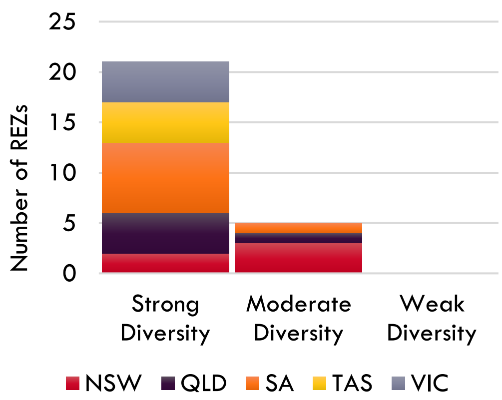
Renewable Resources	**Solar**	**Wind**	**Diversity of Wind with other REZs**
Resource Quality	C	B	
Potential (MW)	4,000	2,785	
Diversity	F	B	
Demand Matching Now 2030 2040	 D F F	 D B B	

Network Limitations	**Existing**	**Upgraded**	**Network Description**
Spare Network Capacity (MW)	3,000	-	The existing network is strong and around 3,000 MW of new generation could be connected without requiring major upgrades. The MLFs are robust compared to the other Queensland REZs, because this REZ is located near the 330 kV interconnector to New South Wales and the South East Queensland load centre. Long-term modelling identified retirement of 1,400 MW of coal-fired generation in the SWQ zone from 2037. This would enable additional solar generation to connect in Darling Downs REZ within the existing transmission capacity.
Initial Loss Factor	B	-	
Loss Factor Robustness	A	-	

Long-Term Market Simulation Scenarios	**Neutral**	**Neutral with Storage**	**Slow**	**Fast**	**High DER**
Generation Built (MW)	3,400	3,400	2,700	4,700	3,000
Timing	>2040	>2040	>2040	>2040	>2040

Table 9 REZ 7 – North West NSW

Summary	**REZ Priority Level = 3**
The North West NSW REZ has been identified by the New South Wales Government as a Potential Priority Energy Zone[8]. There abundant solar resource in the area and there have been a number of connection enquiries received by TransGrid. However the existing 132 kV network is weak and would require significant upgrades. Moree Solar Farm (56 MW) is currently in service.	

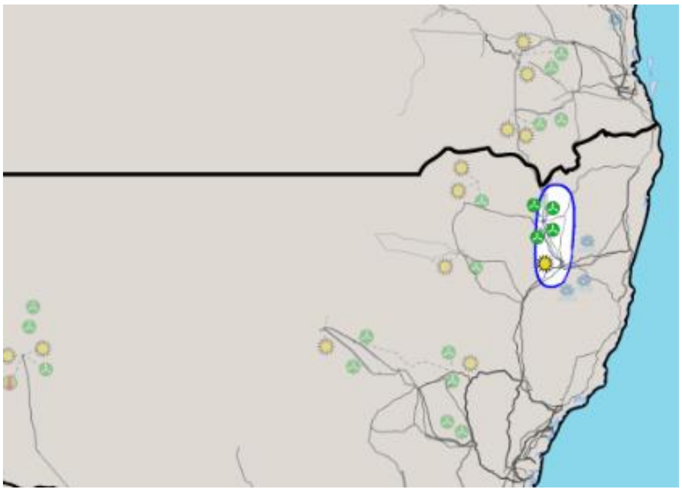
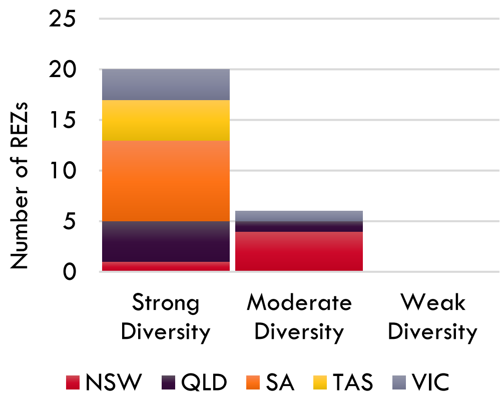
Renewable Resources	**Solar**	**Wind**	**Diversity of Wind with other REZs**
Resource Quality	B	D	
Potential (MW)	3,250	0	
Diversity	F	B	
Demand Matching Now 2030 2040	 C F F	 E C C	

Network Limitations	**Existing**	**Upgraded**	**Network Description**
Spare Network Capacity (MW)	100	3,000	The existing network can only support approximately 100 MW of new generation. One of the options for the new Queensland-New South Wales interconnector passes through this REZ, which would create more opportunities for connection of new generation in this zone. This ISP identifies new 330 kV circuits between Gunnedah area and Wollar would be required to accommodate additional new generation in this REZ.
Initial Loss Factor	C	C	
Loss Factor Robustness	F	B	

Long-Term Market Simulation Scenarios	**Neutral**	**Neutral with Storage**	**Slow**	**Fast**	**High DER**
Generation Built (MW)	3,250	3,250	100	3,250	2,000
Timing	2035	2035	>2040	2029	2037

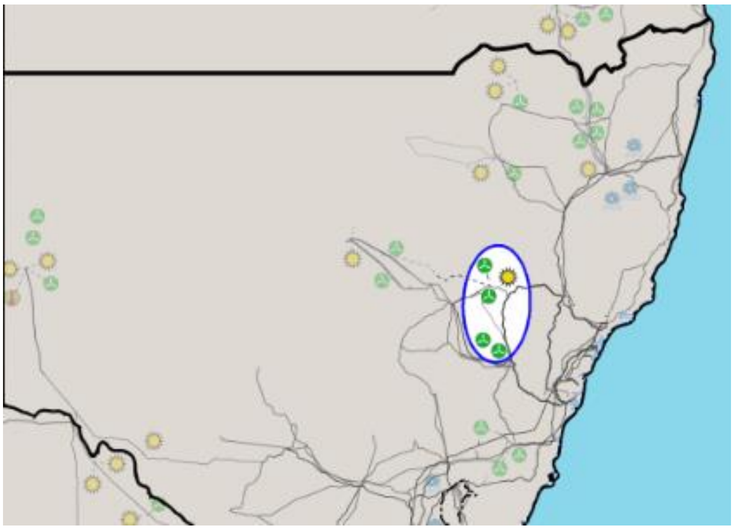
[8] NSW Government. Renewable Energy Hub Knowledge Report. Viewed 4 June 2018. Available at: https://www.resourcesandenergy.nsw.gov.au/data/assets/pdf_file/0006/803751/NSW-Government-Submission-on-Integrated-System-Plan.pdf.

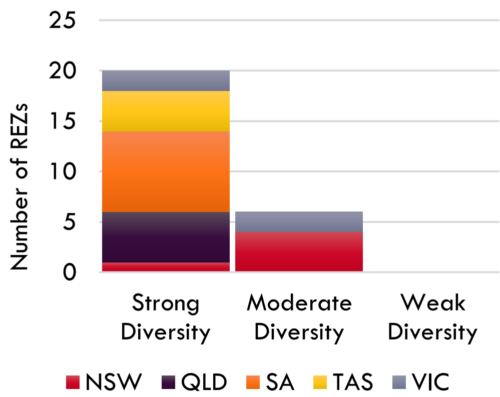
Table 10 REZ 8 – Northern NSW Tablelands

<table>
<tr><th>Summary</th><th colspan="5">REZ Priority Level = 3</th></tr>
<tr><td colspan="2">The Northern NSW Tablelands REZ has a number of locations with good wind resources. This REZ has been identified by the New South Wales Government as a Potential Priority Energy Zone[9]. White Rock Wind Farm (172 MW) and Sapphire Wind Farm (270 MW) are currently in service, and over 600 MW of additional wind generation has been proposed.</td><td colspan="4"></td></tr>
<tr><th>Renewable Resources</th><th>Solar</th><th>Wind</th><th colspan="3">Diversity of Wind with other REZs</th></tr>
<tr><td>Resource Quality</td><td>D</td><td>B</td><td colspan="3" rowspan="4">
</td></tr>
<tr><td>Potential (MW)</td><td>1,750</td><td>3,660</td></tr>
<tr><td>Diversity</td><td>F</td><td>C</td></tr>
<tr><td>Demand Matching
Now
2030
2040</td><td>
C
F
F</td><td>
D
C
C</td></tr>
<tr><th>Network Limitations</th><th>Existing</th><th>Upgraded</th><th colspan="3">Network Description</th></tr>
<tr><td>Spare Network Capacity (MW)</td><td>300</td><td>2,000</td><td colspan="3" rowspan="3">The existing network can support around 300 MW of new connections. Further development could be facilitated after upgrading the Queensland-New South Wales interconnector and network augmentation between Liddell/Bayswater and Northern NSW.</td></tr>
<tr><td>Initial Loss Factor</td><td>D</td><td>-</td></tr>
<tr><td>Loss Factor Robustness</td><td>B</td><td>-</td></tr>
<tr><th>Long-Term Market Simulation Scenarios</th><th>Neutral</th><th>Neutral with Storage</th><th>Slow</th><th>Fast</th><th>High DER</th></tr>
<tr><td>Generation Built (MW)</td><td>1,750</td><td>1,750</td><td>300</td><td>2,200</td><td>1,750</td></tr>
<tr><td>Timing</td><td>2035</td><td>2034</td><td>>2040</td><td>2026</td><td>2036</td></tr>
</table>

[9] NSW Government. Renewable Energy Hub Knowledge Report. Viewed 4 June 2018. Available at: https://www.resourcesandenergy.nsw.gov.au/data/assets/pdf_file/0006/803751/NSW-Government-Submission-on-Integrated-System-Plan.pdf.

Table 11 REZ 9 – Central NSW Tablelands

Summary	REZ Priority Level = 1
The Central NSW Tablelands REZ has good wind resources and some good solar resources at its western edge. It was identified by the New South Wales Government as a Potential Priority Energy Zone[10]. Currently there is only a small amount of generation in the REZ (Bodangora Wind 113 MW and Beryl Solar 100 MW), and more than 2,200 MW of wind projects have been proposed for the area.	

Renewable Resources	Solar	Wind	Diversity of Wind with other REZs
Resource Quality	D	B	
Potential (MW)	3,000	1,600	
Diversity	F	B	
Demand Matching Now 2030 2040	 C F F	 D C C	

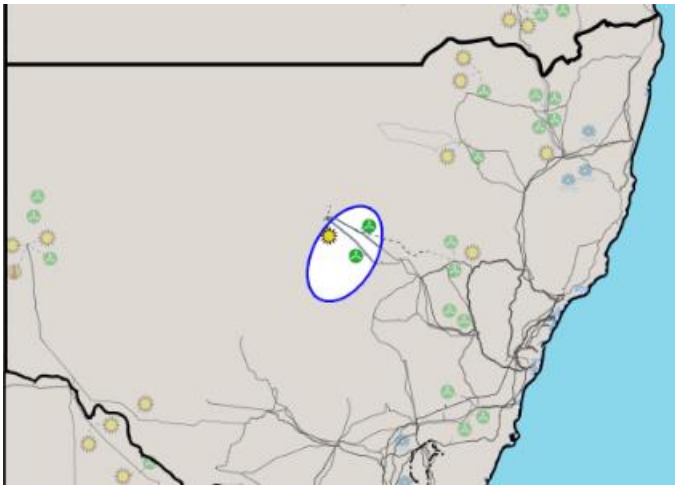
Network Limitations	Existing	Upgraded	Network Description
Spare Network Capacity (MW)	1,000	-	The existing network has capacity to accommodate additional generation of about 1,000 MW. The MLFs are robust because it contains the existing 330 kV and 500 kV network and is electrically close to the Sydney load centre.
Initial Loss Factor	A	-	
Loss Factor Robustness	A	-	

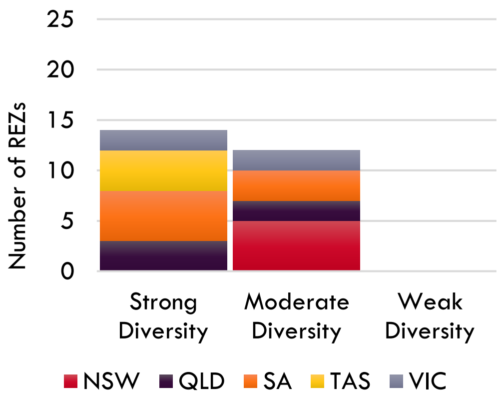
Long-Term Market Simulation Scenarios	Neutral	Neutral with Storage	Slow	Fast	High DER
Generation Built (MW)	1,000	1,000	0	3,500[11]	1,000
Timing	>2040	>2040	-	2023	>2040

[10] NSW Government. Renewable Energy Hub Knowledge Report. Viewed 4 June 2018. Available at: https://www.resourcesandenergy.nsw.gov.au/data/assets/pdf_file/0006/803751/NSW-Government-Submission-on-Integrated-System-Plan.pdf.

[11] Significant transmission development would be required to accommodate developments to this level.

Table 12 REZ 10 – Central West NSW

Summary	REZ Priority Level = Low
The Central West NSW REZ has moderate wind and solar resources. It was identified by the New South Wales Government as a Potential Priority Energy Zone[12]. It is also supported by Central NSW Councils. Nyngan Solar Farm (102 MW) is currently in service. Parkes Solar Farm (55 MW) and Manildra Solar Farm (50 MW) are committed and there are many proposed solar projects.	

Renewable Resources	Solar	Wind	Diversity of Wind with other REZs
Resource Quality	C	C	
Potential (MW)	3,750	1,420	
Diversity	F	C	
Demand Matching Now 2030 2040	 C F F	 E C C	

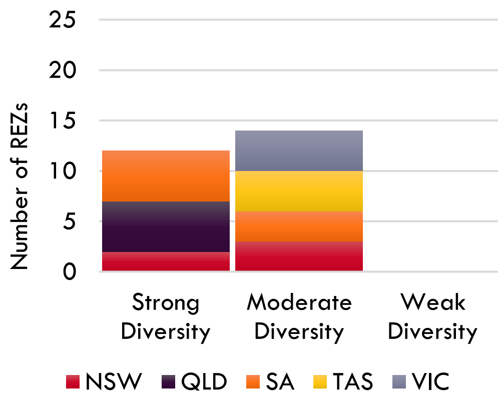
Network Limitations	Existing	Upgraded	Network Description
Spare Network Capacity (MW)	100	1,500	The existing 132 kV network is very weak and would become constrained with large generator connections, so significant development would be required to enable generation in this REZ. A possible option is to extend the 330 kV transmission line from Wellington to this REZ. With this network extension, MLFs would be very robust to new generation.
Initial Loss Factor	B	E	
Loss Factor Robustness	E	A	

Long-Term Market Simulation Scenarios	Neutral	Neutral with Storage	Slow	Fast	High DER
Generation Built (MW)	1,300	932	0	1,300	100
Timing	2037	2039	-	2037	>2040

[12] NSW Government. Renewable Energy Hub Knowledge Report. Viewed 4 June 2018. Available at: https://www.resourcesandenergy.nsw.gov.au/data/assets/pdf_file/0006/803751/NSW-Government-Submission-on-Integrated-System-Plan.pdf.

Table 13 REZ 11 – Southern NSW Tablelands

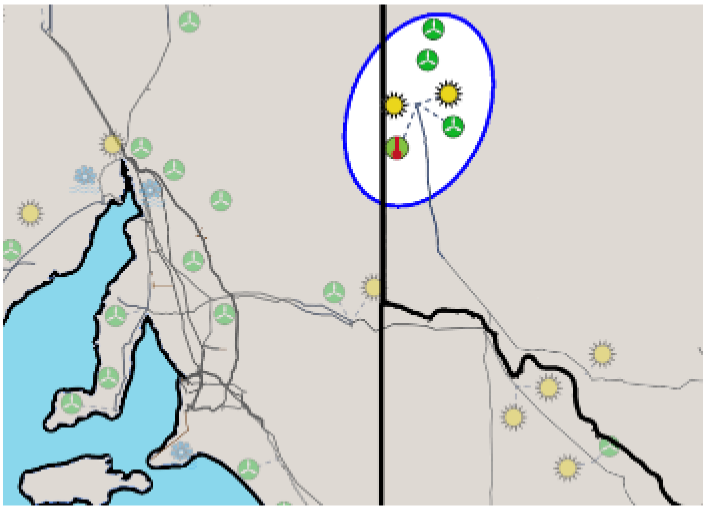
Summary	**REZ Priority Level = Low**
The Southern NSW Tablelands REZ has excellent wind resources. Over 500 MW of wind farms are currently in service, along with 240 MW pumped hydro at Shoalhaven. In their submission to the ISP consultation, the New South Wales Government indicated a risk that local communities may not support further development in this area.	

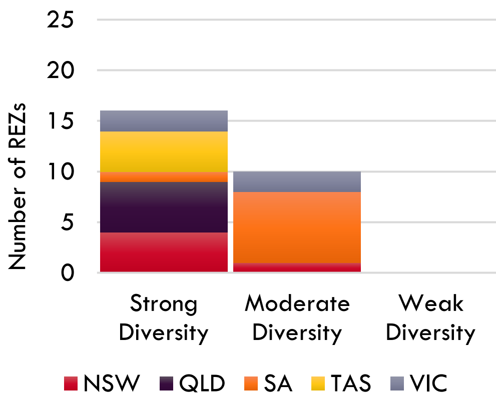
Renewable Resources	**Solar**	**Wind**	**Diversity of Wind with other REZs**
Resource Quality	E	A	
Potential (MW)	1,000	2,310	
Diversity	Not studied	C	
Demand Matching Now 2030 2040	 Not studied	 D C C	

Network Limitations	**Existing**	**Upgraded**	**Network Description**
Spare Network Capacity (MW)	1,000	3,000	The REZ is close to four 330 kV transmission lines and two 500 kV transmission lines supporting Sydney. The existing network could support over 1,000 MW of new connections. The MLFs are robust, remaining stable with high levels of connected generation.
Initial Loss Factor	A	-	
Loss Factor Robustness	A	A	

Long-Term Market Simulation Scenarios	**Neutral**	**Neutral with Storage**	**Slow**	**Fast**	**High DER**
Generation Built (MW)	2,300	2,300	600	2,300	2,300
Timing	2036	2036	>2040	2036	2036

Table 14 REZ 12 – Broken Hill

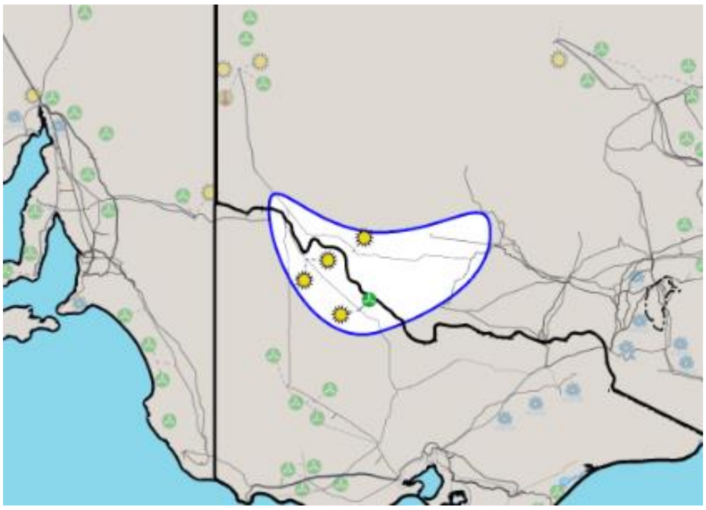
Summary	REZ Priority Level = Low
The Broken Hill REZ has good wind and solar resources. Broken Hill Solar Plant (53 MW) was recently commissioned and Silverton Wind Farm (199 MW) is a committed project.	

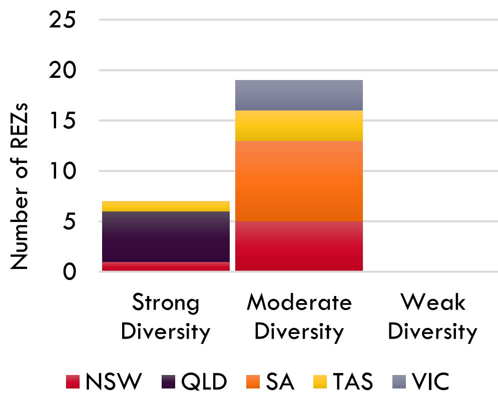
Renewable Resources	Solar	Wind	Diversity of Wind with other REZs
Resource Quality	B	B	
Potential (MW)	4,000	2,490	
Diversity	F	C	
Demand Matching Now 2030 2040	 B F F	 E C C	

Network Limitations	Existing	Upgraded	Network Description
Spare Network Capacity (MW)	100	-	The area is supplied by a single 220 kV line, approximately 270 km from Buronga. There is not much local load and the MLF will decline sharply with large generator connections.
Initial Loss Factor	A	-	
Loss Factor Robustness	E	-	

Long-Term Market Simulation Scenarios	Neutral	Neutral with Storage	Slow	Fast	High DER
Generation Built (MW)	100	100	100	100	100
Timing	>2040	>2040	>2040	>2040	>2040

Table 15 REZ 13 – Murray River

Summary	REZ Priority Level = 2
The Murray River REZ spans the western section of the New South Wales and Victorian border. The area has moderate wind and solar resources. Over 2,000 MW of solar generation is proposed for the area. The New South Wales part of this zone aligns with the area identified by the New South Wales Government as a Potential Priority Energy Zone[13].	

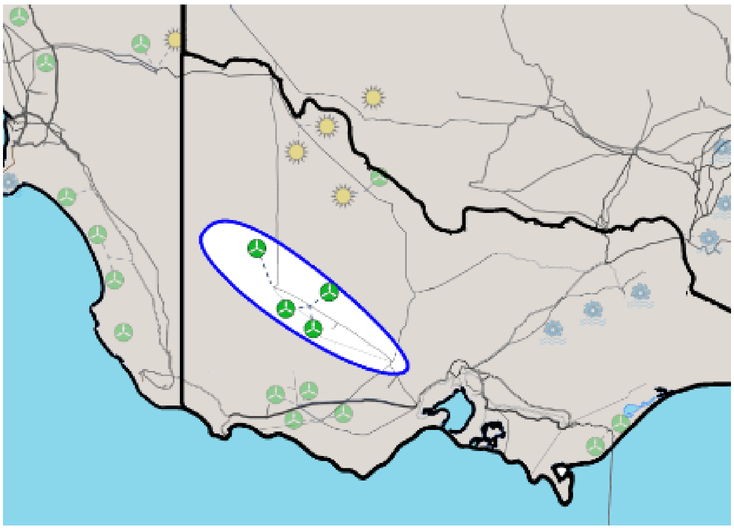
Renewable Resources	Solar	Wind	Diversity of Wind with other REZs
Resource Quality	C	C	
Potential (MW)	6,000	9,140	
Diversity	F	D	
Demand Matching Now 2030 2040	 B F F	 D C C	

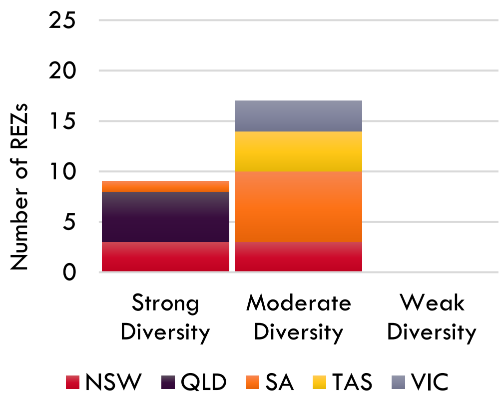
Network Limitations	Existing	Upgraded	Network Description
Spare Network Capacity (MW)	0 (NSW side) 300 (Vic side)	2,000 (NSW) 2,000 (VIC)	The existing network is electrically weak and the MLFs will decline sharply as new generators are connected. Capacity in Victoria is improved with 220 kV upgrades along the Buronga-Red Cliffs-Kerang-route, and new 500 kV Darlington Point-Kerang lines with the proposed SnowyLink interconnector. Capacity in New South Wales is improved with the proposed RiverLink New South Wales-South Australia interconnector.
Initial Loss Factor	A	-	
Loss Factor Robustness	E	-	

Long-Term Market Simulation Scenarios	Neutral	Neutral with Storage	Slow	Fast	High DER
Generation Built (MW)	3,000 (NSW) 2,300 (VIC)	3,000 (NSW) 2,300 (VIC)	0 (NSW) 1,000 (VIC)	3,000 (NSW) 3000 (VIC)	1,200 (NSW) 1000 (VIC)
Timing	2035 (NSW) 2024 (VIC)	2035 (NSW) 2024 (VIC)	2024 (VIC)	2035 (NSW) 2024 (VIC)	2037 (NSW) 2024 (VIC)

[13] NSW Government. Renewable Energy Hub Knowledge Report. Viewed 4 June 2018. Available at: https://www.resourcesandenergy.nsw.gov.au/data/assets/pdf_file/0006/803751/NSW-Government-Submission-on-Integrated-System-Plan.pdf.

Table 16 REZ 14 – Western Victoria

Summary	REZ Priority Level = 3
The Western Victoria REZ has been identified for its excellent wind resources and quantity of connection enquiries received in the area. There is already 720 MW of wind farms in service and over 1,700 MW of new wind farms have been proposed. AEMO is undertaking the "Western Victoria Renewable Integration" RIT-T to identify the best network investment option for upgrades to facilitate these connections. The proposed SnowyLink development options would also aid the development of the REZ.	

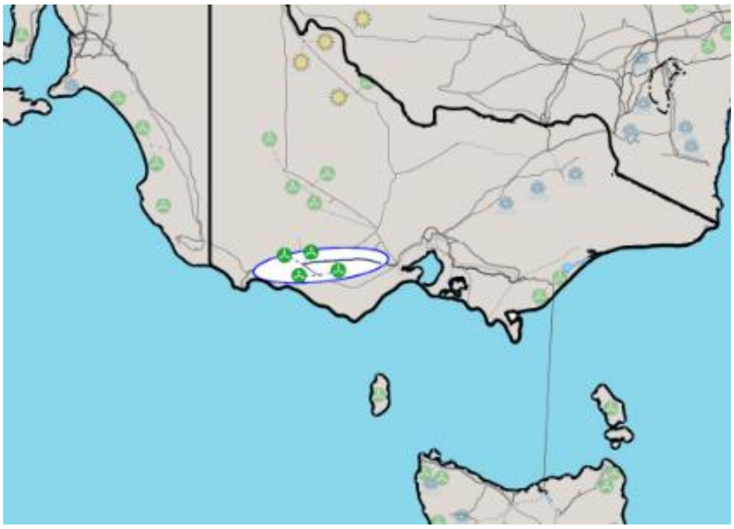
Renewable Resources	Solar	Wind	Diversity of Wind with other REZs
Resource Quality	E	A	
Potential (MW)	0	1,580	
Diversity	Not studied	D	
Demand Matching Now 2030 2040	Not studied	 C C C	

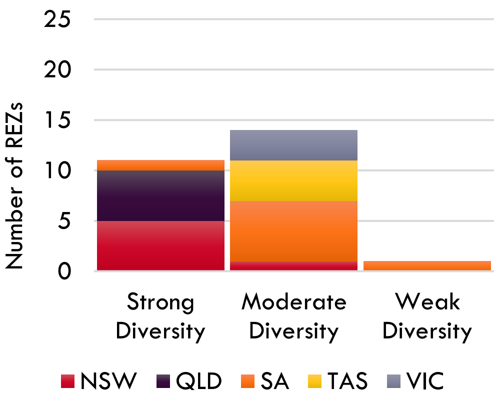
Network Limitations	Existing	Upgraded	Network Description
Spare Network Capacity (MW)	0	2,500	The existing network is constrained and cannot support any new connections. The MLFs would decline sharply with additional generation. Augmentation options include adding 220 kV capacity along the Horsham to Ballarat path, and extending the 500 kV network from Sydenham to Ballarat as part of the SnowyLink interconnetor.
Initial Loss Factor	B	-	
Loss Factor Robustness	D	-	

Long-Term Market Simulation Scenarios	Neutral	Neutral with Storage	Slow	Fast	High DER
Generation Built (MW)[A]	800	400	800	1,600	800
Timing	2025	2024	2025	2020	2025

A. Generation built is in addition to the existing and committed wind power generation of 1,600 MW in WVIC REZ.

Table 17 REZ 15 – Moyne

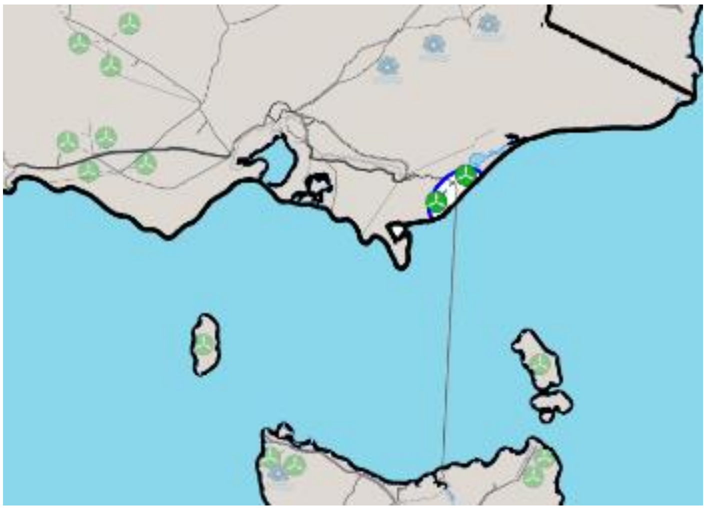
Summary	REZ Priority Level = 1
The Moyne REZ has good wind resources. Several large wind farms including Macarthur (420 MW) and Portland (149 MW) are already in service, and a further 1,600 MW has been proposed.	

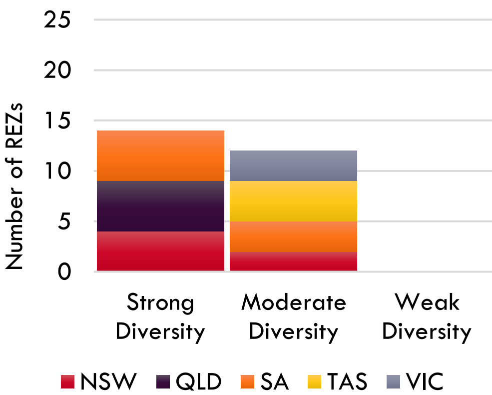
Renewable Resources	Solar	Wind	Diversity of Wind with other REZs
Resource Quality	E	B	
Potential (MW)	0	2,295	
Diversity	Not studied	D	
Demand Matching Now 2030 2040	Not studied	 C C C	

Network Limitations	Existing	Upgraded	Network Description
Spare Network Capacity (MW)	2,000	-	The electrically strong 500 kV network between Melbourne and South Australia passes through this REZ. The MLFs are robust as new generation is connected. No augmentations are proposed within the REZ itself. However, upgrades in the Melbourne/Geelong area may be required to allow full output from the REZ.
Initial Loss Factor	A	-	
Loss Factor Robustness	C	-	

Long-Term Market Simulation Scenarios	Neutral	Neutral with Storage	Slow	Fast	High DER
Generation Built (MW)	2,300	2,300	2,300	2,300	2,000
Timing	2037	2037	>2040	2032	>2040

Table 18 REZ 16 – Gippsland

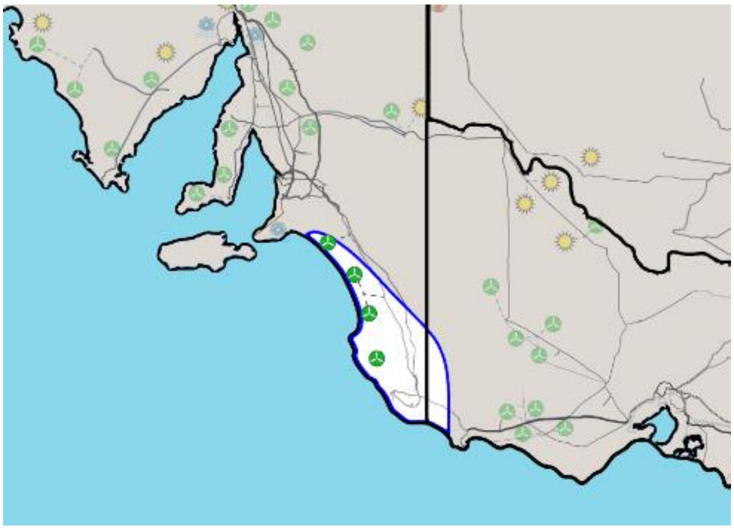
Summary	REZ Priority Level = Low
The Gippsland REZ contains one wind farm currently in service, Bald Hills (106 MW). A large offshore wind farm (2,000 MW) has also been proposed.	

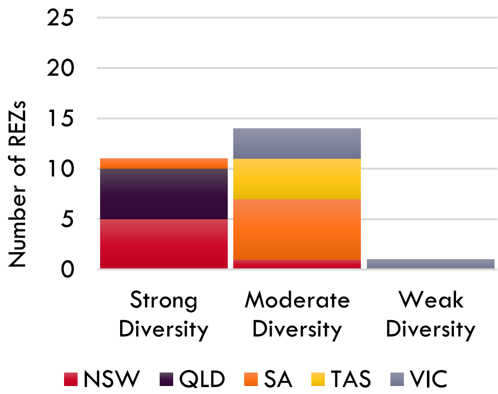
Renewable Resources	Solar	Wind	Diversity of Wind with other REZs
Resource Quality	E	D	
Potential (MW)	0	140	
Diversity	Not studied	C	
Demand Matching Now 2030 2040	Not studied	D C C	

Network Limitations	Existing	Upgraded	Network Description
Spare Network Capacity (MW)	2,000	-	There is no major transmission network passing through the area, but it is within 60 km of the 500 kV substations where Loy Yang and Basslink are connected. If this network were to be extended, then many new connections could be facilitated and the MLFs would be robust.
Initial Loss Factor	-	-	
Loss Factor Robustness	A	-	

Long-Term Market Simulation Scenarios	Neutral	Neutral with Storage	Slow	Fast	High DER
Generation Built (MW)	140	35	140	140	140
Timing	>2040	>2040	>2040	>2040	>2040

Table 19 REZ 17 – South-East SA

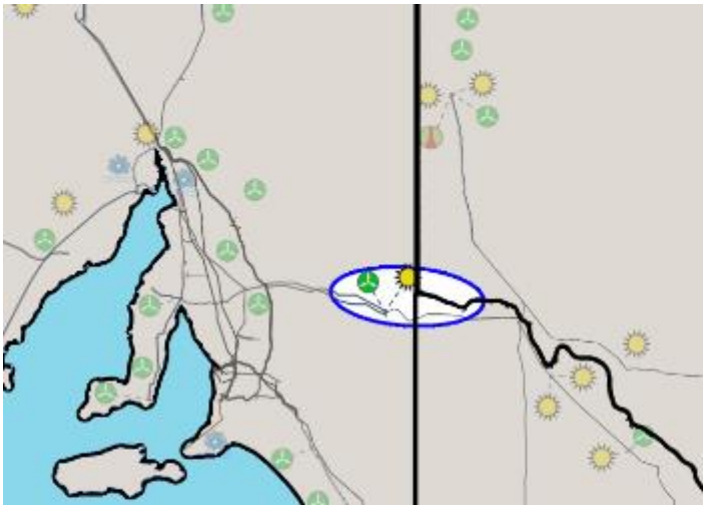
Summary	**REZ Priority Level = Low**
The South-East SA REZ has good wind resources. Over 300 MW of wind farms at Canunda and Lake Bonney are in service. An additional 380 MW has been proposed.	

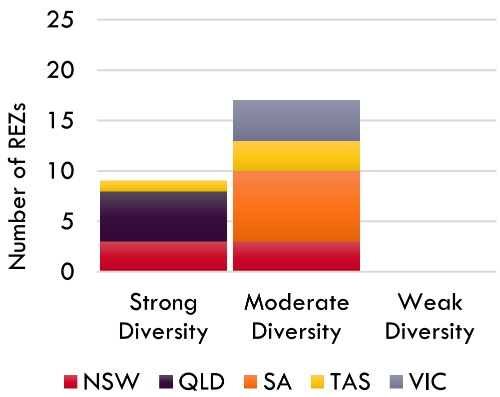
Renewable Resources	**Solar**	**Wind**	**Diversity of Wind with other REZs**
Resource Quality	E	B	
Potential (MW)	0	1,810	
Diversity	Not studied	D	
Demand Matching Now 2030 2040	 Not studied	 C C C	

Network Limitations	**Existing**	**Upgraded**	**Network Description**
Spare Network Capacity (MW)	500	-	The major 275 KV path linking South Australia with Victoria passes through this REZ, and the existing network can accommodate about 500 MW additional generation. The MLF is sensitive to additional generation because the REZ is not close to any major load centres.
Initial Loss Factor	B	-	
Loss Factor Robustness	D	-	

Long-Term Market Simulation Scenarios	**Neutral**	**Neutral with Storage**	**Slow**	**Fast**	**High DER**
Generation Built (MW)	0	84	0	375	0
Timing	-	>2040	-	>2040	-

Table 20 REZ 18 – Riverland

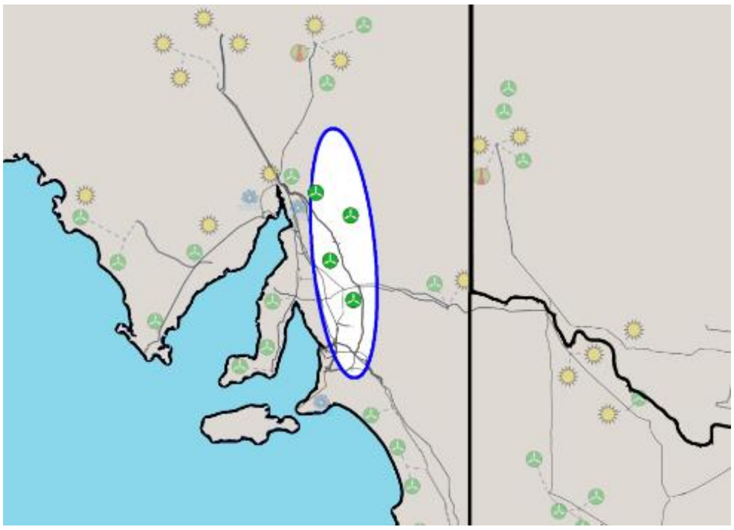
Summary	REZ Priority Level = Low
The Riverland REZ spans the South Australia, New South Wales, and Victorian border. It has moderate quality wind and solar resources. 330 MW solar generation is proposed in this REZ, for connection to the ElectraNet transmission network.	

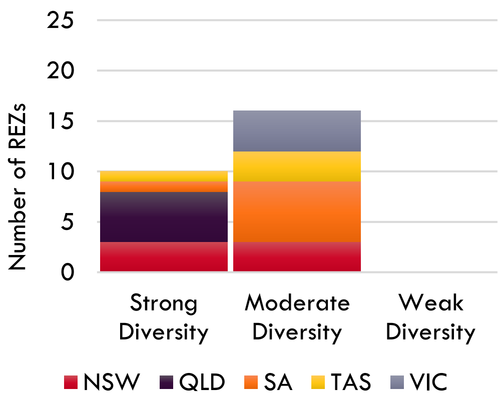
Renewable Resources	Solar	Wind	Diversity of Wind with other REZs
Resource Quality	C	C	
Potential (MW)	2,000	620	
Diversity	F	D	
Demand Matching Now 2030 2040	 B F F	 D C C	

Network Limitations	Existing	Upgraded	Network Description
Spare Network Capacity (MW)	200	2,000	There is no spare capacity on the South Australia side, and no connection to Victoria or New South Wales networks. The proposed RiverLink New South Wales-South Australia interconnector passes through this REZ and will enable generation to be connected. The MLF drops sharply as new generation is connected.
Initial Loss Factor	A	C	
Loss Factor Robustness	E	-	

Long-Term Market Simulation Scenarios	Neutral	Neutral with Storage	Slow	Fast	High DER
Generation Built (MW)	1,950	1,950	0	2,000	1,950
Timing	2033	2032	-	2024	2036

Table 21 REZ 19 – Mid-North SA

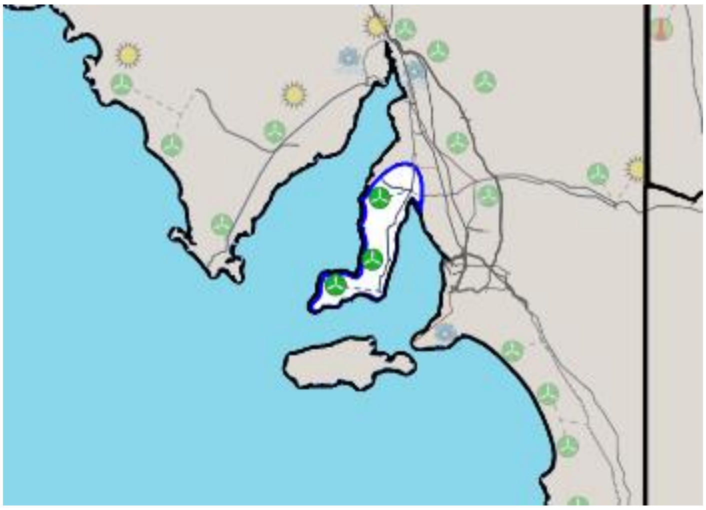
Summary	REZ Priority Level = 2
The Mid-North SA REZ has good wind and moderate solar resources. There are several major wind farms totalling 795 MW in service, including Hallett, Hornsdale, North Brown Hill, and Waterloo. The 100 MW/129 MWh Hornsdale battery storage is also contained in this REZ. An additional 600 MW of wind farms have been proposed in the REZ.	

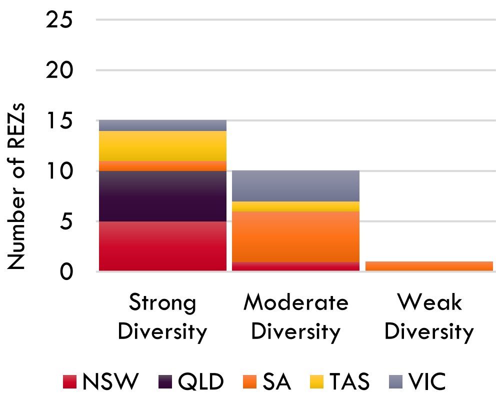
Renewable Resources	Solar	Wind	Diversity of Wind with other REZs
Resource Quality	C	B	
Potential (MW)	0	2,425	
Diversity	Not studied	D	
Demand Matching Now 2030 2040	Not studied	C C C	

Network Limitations	Existing	Upgraded	Network Description
Spare Network Capacity (MW)	1,000	-	Four 275 kV circuits pass through the REZ, and about 1,000 MW additional generation can be accommodated in these 275 kV circuits. However, additional new generation in this zone is subject to new generation connection in remaining REZs in North South Australia region. The MLF is moderately robust to additional generation connections.
Initial Loss Factor	B	-	
Loss Factor Robustness	C	-	

Long-Term Market Simulation Scenarios	Neutral	Neutral with Storage	Slow	Fast	High DER
Generation Built (MW)	450	600	0	600	150
Timing	>2040	>2040	-	>2040	>2040

Table 22 REZ 20 – Yorke Peninsula

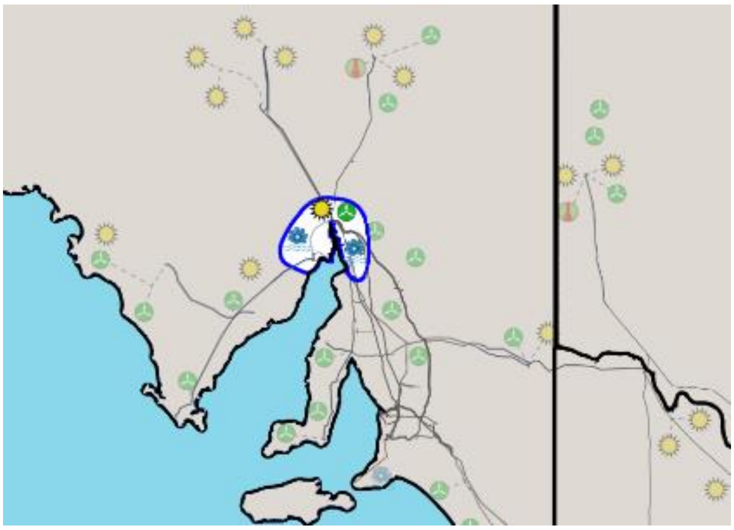
Summary	REZ Priority Level = Low
The Yorke Peninsula REZ has good quality wind resources. The wind farms at Clements Gap (56 MW), Snowtown (99MW and 270 MW), and Wattle Point (90 MW) are currently in service. An additional 960 MW has been proposed.	

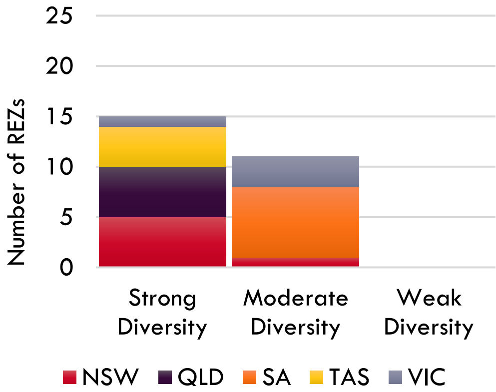
Renewable Resources	Solar	Wind	Diversity of Wind with other REZs
Resource Quality	D	B	
Potential (MW)	0	620	
Diversity	Not studied	D	
Demand Matching Now 2030 2040	Not studied	C C C	

Network Limitations	Existing	Upgraded	Network Description
Spare Network Capacity (MW)	50	900	A single 132 kV line extends from Hummocks to Wattle Point (towards end of Yorke Peninsula). It can only support an additional 50 MW capacity of new generator connections before upgrading would be necessary. A possible augmentation would be a 275 kV double circuit line from Dalrymple. This would increase the capacity, but the MLF would still decline rapidly as new generation is connected, due to the distance from any major load.
Initial Loss Factor	C	A	
Loss Factor Robustness	F	E	

Long-Term Market Simulation Scenarios	Neutral	Neutral with Storage	Slow	Fast	High DER
Generation Built (MW)	0	0	0	0	0
Timing	-	-	-	-	-

Table 23 REZ 21 – Northern SA

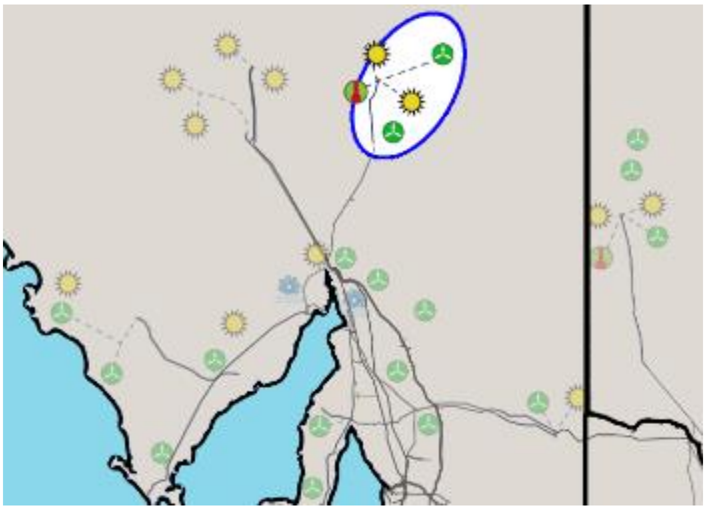
Summary	REZ Priority Level = 1
The Northern SA REZ has good wind and moderate solar resources. Bungala Solar (220 MW) and Lincoln Gap Wind (126 MW) are currently committed projects. Over 1,100 MW of new generation has been proposed, with a diverse mix of solar thermal, wind, solar PV, and pumped hydro	

Renewable Resources	Solar	Wind	Diversity of Wind with other REZs
Resource Quality	C	B	
Potential (MW)	1,500	0	
Diversity	F	C	
Demand Matching Now 2030 2040	 E F F	 C C C	

Network Limitations	Existing	Upgraded	Network Description
Spare Network Capacity (MW)	1,000	-	About 1,000 MW additional generation can be accommodated in this REZ. However, additional new generation in this zone is subject to new generation connection in remaining REZs in North South Australia region. The REZ is close to the major load centre at Adelaide and the MLFs are very robust.
Initial Loss Factor	B	-	
s Factor Robustness	B	-	

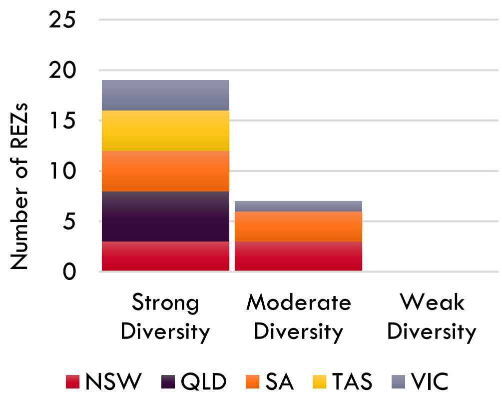
Long-Term Market Simulation Scenarios	Neutral	Neutral with Storage	Slow	Fast	High DER
Generation Built (MW)	1,000	1,000	0	1,800	1,000
Timing	>2040	>2040	-	2037	>2040

Table 24 REZ 22 – Leigh Creek

Summary	REZ Priority Level = Low
The Leigh Creek REZ is located a few hundred km north of Davenport. It has excellent solar resources and good wind resources. There has also been high level discussion about the potential for geothermal in the REZ.	

Renewable Resources	Solar	Wind
Resource Quality	A	B
Potential (MW)	3,250	1,190
Diversity	F	B
Demand Matching Now 2030 2040	 E F F	 D C B

Diversity of Wind with other REZs



Network Limitations	Existing	Upgraded	Network Description
Spare Network Capacity (MW)	10	1,400	The REZ is currently supplied with a single 132 kV line that does not have any spare capacity. A possible augmentation could involve extending the 275 kV network from Davenport to this REZ. The MLF would still decline rapidly with new generation, due to the distance from any major load.
Initial Loss Factor	A	A	
Loss Factor Robustness	F	E	

Long-Term Market Simulation Scenarios	Neutral	Neutral with Storage	Slow	Fast	High DER
Generation Built (MW)	10	10	10	10	10
Timing	>2040	>2040	>2040	>2040	>2040

Table 25 REZ 23 – Roxby Downs

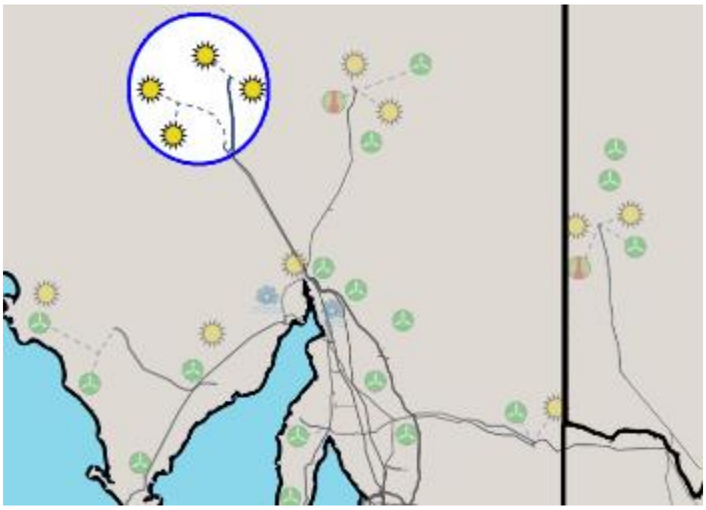
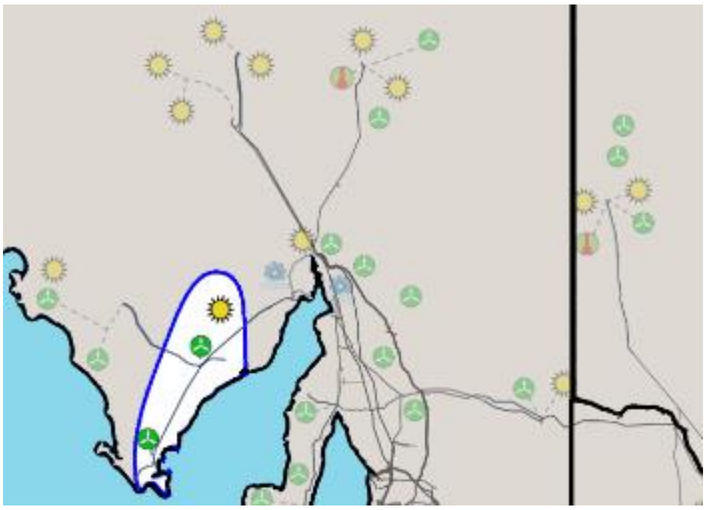
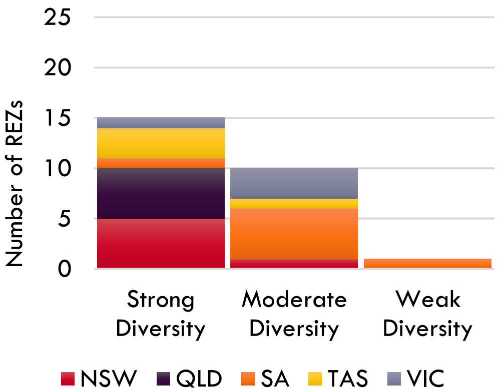
Summary		**REZ Priority Level = 3**			
The Roxby Downs REZ is located a few hundred km north-west of Davenport. It has excellent solar resources. The only significant load in the area is at the Olympic Dam.					
Renewable Resources	**Solar**	**Wind**	**Diversity of Wind with other REZs**		
Resource Quality	A	C	**Not studied**		
Potential (MW)	1,700	0			
Diversity	F	Not studied			
Demand Matching Now 2030 2040	 E F F	Not studied			
Network Limitations	**Existing**	**Upgraded**	**Network Description**		
Spare Network Capacity (MW)	960	1,400	This REZ is currently connected with a 132 kV line and privately owned 275 kV line from Davenport. ElectraNet is in the process of installing a 275 kV circuit from Davenport to Mount Gunson South to supply Prominent Hill. The MLF would still decline rapidly with new generation, due to the distance from any major load.		
Initial Loss Factor	A	A			
Loss Factor Robustness	E	E			
Long-Term Market Simulation Scenarios	**Neutral**	**Neutral with Storage**	**Slow**	**Fast**	**High DER**
Generation Built (MW)	1,400	1,050	800	1,700	960
Timing	2037	2040	>2040	2028	>2040

Table 26 REZ 24 – Eastern Eyre Peninsula

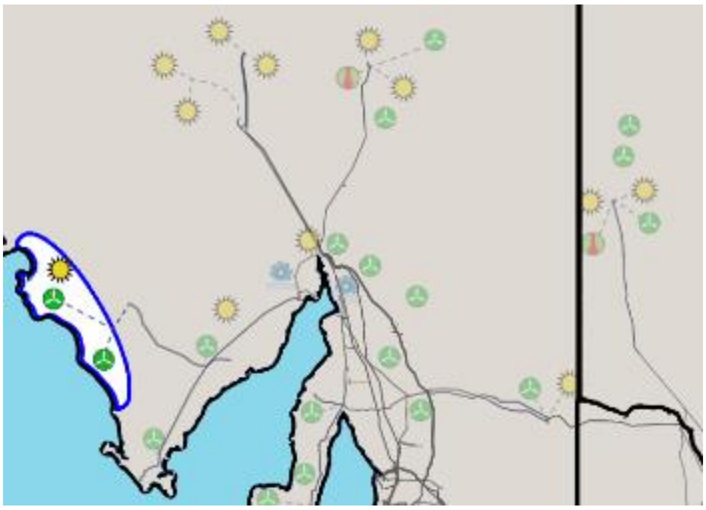
Summary	REZ Priority Level = Low
The Eastern Eyre Peninsula REZ has good wind resources. Cathedral Rocks (66 MW) and Mt Millar (70 MW) wind farms are in service. ElectraNet is currently undertaking a RIT-T for transmission development to support this area.	

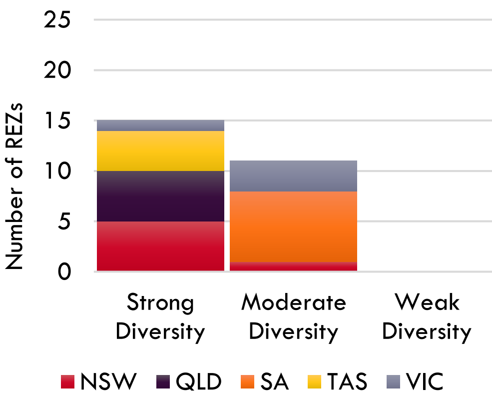
Renewable Resources	Solar	Wind	Diversity of Wind with other REZs
Resource Quality	D	B	
Potential (MW)	2,500	1,160	
Diversity	F	C	
Demand Matching Now 2030 2040	 E F F	 C C C	

Network Limitations	Existing	Upgraded	Network Description
Spare Network Capacity (MW)	500	1000	The REZ is currently supplied by a single 132 kV line extending 250 km south of Cultana. ElectraNet is currently undertaking a RIT-T to replace the existing Cultana-Yadnarie-Port Lincoln 132 kV single circuit line with a new double circuit line. The spare network capacity asumes the additional capacity available following installation of the new double circuit line. The MLF will continue to decline rapidly with any additional generation. Even with upgrading the network halfway along the Peninsula to 275 kV and augmenting the remaining 132 kV lines, the MLF does not become much stronger.
Initial Loss Factor	C	B	
Loss Factor Robustness	F	D	

Long-Term Market Simulation Scenarios	Neutral	Neutral with Storage	Slow	Fast	High DER
Generation Built (MW)	500	500	0	500	100
Timing	>2040	>2040	-	>2040	>2040

Table 27 REZ 25 – Western Eyre Peninsula

Summary	REZ Priority Level = Low
The Western Eyre Peninsula REZ shares the same supply as the Eastern Eyre Peninsula. It has good wind resources and moderate solar resources. There are currently no generators connected in the REZ.	

Renewable Resources	Solar	Wind	Diversity of Wind with other REZs
Resource Quality	C	B	
Potential (MW)	2,000	715	
Diversity	F	C	
Demand Matching Now 2030 2040	 E F F	 C C C	

Network Limitations	Existing	Upgraded	Network Description
Spare Network Capacity (MW)	0	500	The MLF is already very low at the Eastern Eyre Peninsula, and will be even weaker at the Western Eyre Peninsula. A potential upgrade could involve extension of the 275 kV 300 km west from Davenport, but the MLF will still be sensitive to new generator connections.
Initial Loss Factor	A	A	
Loss Factor Robustness	F	E	

Long-Term Market Simulation Scenarios	Neutral	Neutral with Storage	Slow	Fast	High DER
Generation Built (MW)	0	0	0	0	0
Timing	-	-	-	-	-

Table 28 REZ 26 – King Island

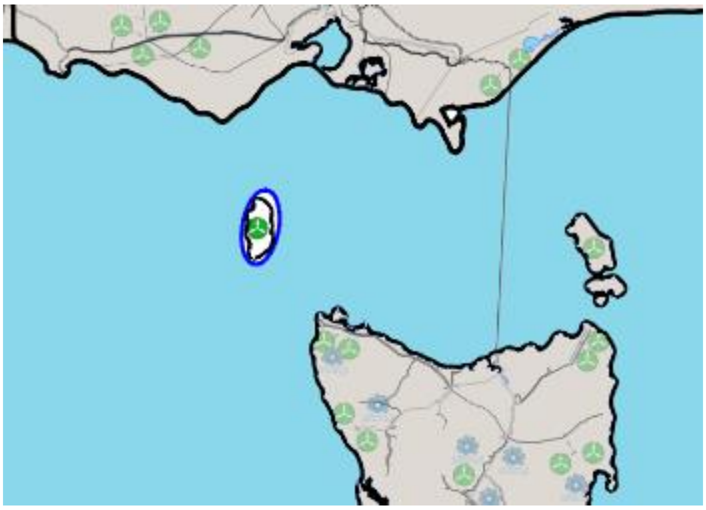
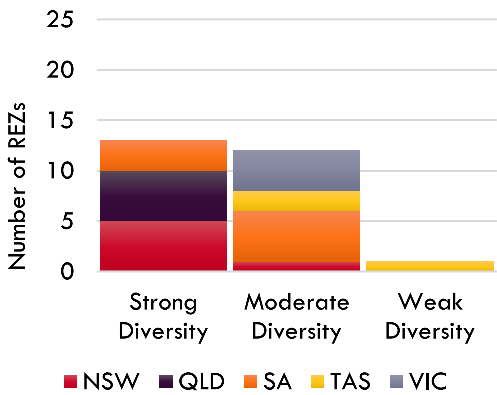
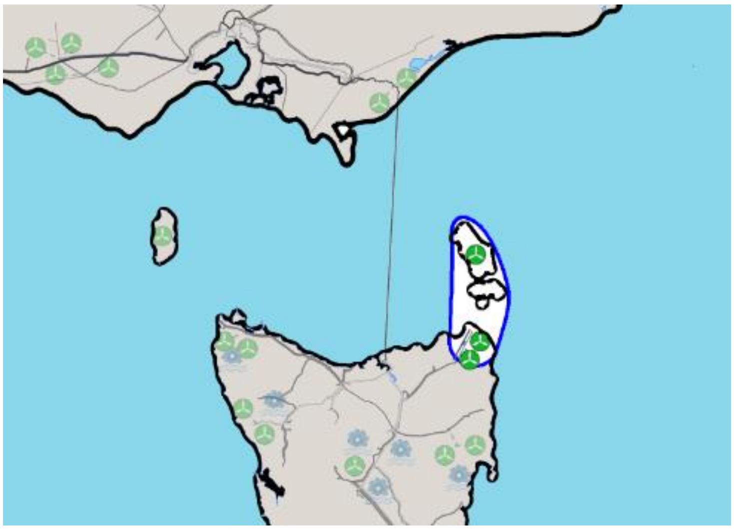
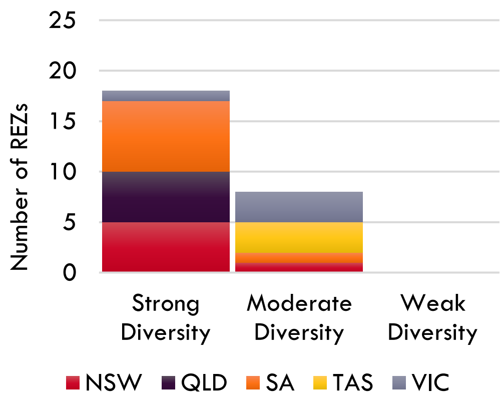
Summary		**REZ Priority Level = Low**			
King Island has excellent wind resources.					
Renewable Resources	**Solar**	**Wind**	**Diversity of Wind with other REZs**		
Resource Quality	E	A			
Potential (MW)	600	600			
Diversity	C	C			
Demand Matching Now 2030 2040	 B B B	 B B B			
Network Limitations	**Existing**	**Upgraded**	**Network Description**		
Spare Network Capacity (MW)	0	-	There is no existing connection to the NEM at King Island.		
Initial Loss Factor	-	-			
Loss Factor Robustness	-	-			
Long-Term Market Simulation Scenarios	**Neutral**	**Neutral with Storage**	**Slow**	**Fast**	**High DER**
Generation Built (MW)	0	0	0	0	0
Timing	-	-	-	-	-

Table 29 REZ 27 – North-East Tasmania

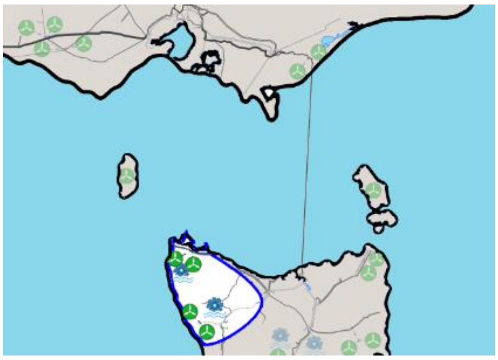
Summary	**REZ Priority Level = Low**
The North-East Tasmania REZ hsa excellent wind resources. Currently Musselroe (168 MW) wind farm is in service.	

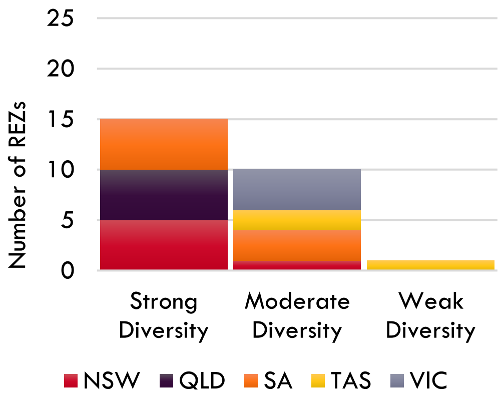
Renewable Resources	**Solar**	**Wind**	**Diversity of Wind with other REZs**
Resource Quality	E	A	
Potential (MW)	0	305	
Diversity	Not studied	B	
Demand Matching Now 2030 2040	Not studied	C B C	

Network Limitations	**Existing**	**Upgraded**	**Network Description**
Spare Network Capacity (MW)	0	500	The 110 kV network does not have any spare capacity. A 220 kV network extension would increase network capacity. However, the MLF would not be very robust to large generator connections.
Initial Loss Factor	C	A	
Loss Factor Robustness	F	C	

Long-Term Market Simulation Scenarios	**Neutral**	**Neutral with Storage**	**Slow**	**Fast**	**High DER**
Generation Built (MW)	0	0	0	0	0
Timing	-	-	-	-	-

Table 30 REZ 28 – North-West Tasmania

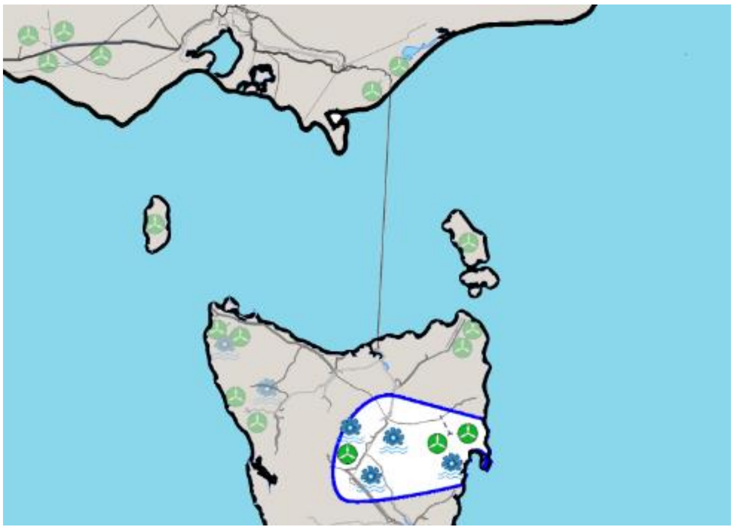
Summary	**REZ Priority Level = 2**
The North-West Tasmania REZ has excellent wind resources. It covers North-West and West Coast Tasmania. Currently there are many hydro generators connected (867 MW total) and Studland Bay and Bluff Point Wind Farms (140 MW).	

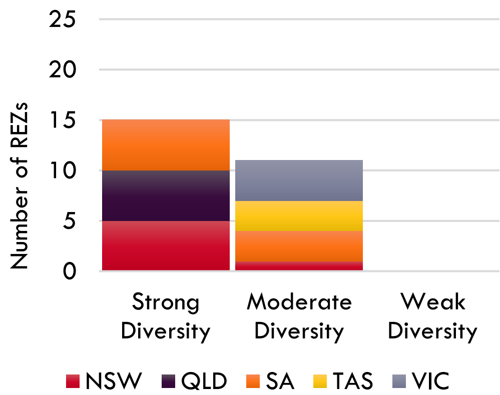
Renewable Resources	**Solar**	**Wind**	**Diversity of Wind with other REZs**
Resource Quality	E	A	
Potential (MW)	0	2,000	
Diversity	Not studied	C	
Demand Matching Now 2030 2040	Not studied	C C C	

Network Limitations	**Existing**	**Upgraded**	**Network Description**
Spare Network Capacity (MW)	200	500	There is no spare capacity available in the 110 kV circuits west of Burnie. Farrell substation is connected by two 220 kV circuits from Sheffield. An additional 200 MW generation can be connected to this 220 kV circuits. For additional wind generation in North-West Tasmania, the 220 kV network would need to be extended from Sheffield to Port Latta or Smithton. The modelling showed a standalone network upgrade to 220 kV would not greatly improve the robustness of the MLF. This result would be different if a second Bass Strait interconnector was built and connected at Port Latta/Smithton, providing the REZ a strong connection to the mainland.
Initial Loss Factor	B	B	
Loss Factor Robustness	E	D	

Long-Term Market Simulation Scenarios	**Neutral**	**Neutral with Storage**	**Slow**	**Fast**	**High DER**
Generation Built (MW)	94	500	0	260	0
Timing	>2040	2035	-	2031	-

Table 31 REZ 29 – Tasmania Midlands

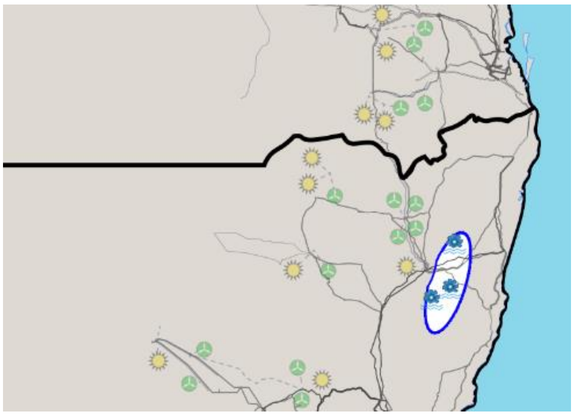
Summary	REZ Priority Level = 1
The Tasmania Midlands REZ has excellent wind resources. It is located closer to the major load centre at Hobart. Currently there are many hydro generators connected (1,412 MW total).	

Renewable Resources	Solar	Wind	Diversity of Wind with other REZs
Resource Quality	E	A	
Potential (MW)	0	1,730	
Diversity	Not studied	C	
Demand Matching Now 2030 2040	Not studied	 C B B	

Network Limitations	Existing	Upgraded	Network Description
Spare Network Capacity (MW)	1,000	-	The Palmerton-Waddamana-Liapootah and Waddamana-Lindisfarne 220 kV circuits pass through this REZ. About 1,000 MW additonal generation can be accommodated in this area, subject to dispatch of hydro generation in Southern Tasmania. The MLF declines with additional generation is only moderate.
Initial Loss Factor	B	-	
Loss Factor Robustness	C	-	

Long-Term Market Simulation Scenarios	Neutral	Neutral with Storage	Slow	Fast	High DER
Generation Built (MW)	400	1,300	0	700	300
Timing	>2040	2037	-	>2040	>2040

Table 32 REZ 30 – New England

Summary	REZ Priority Level = 3
The New England REZ has been identified with many potential sites for pumped hydro. The wind resource quality is also good. The New South Wales government has identified west of this REZ as part of a Potential Priority Energy Zone[14].	

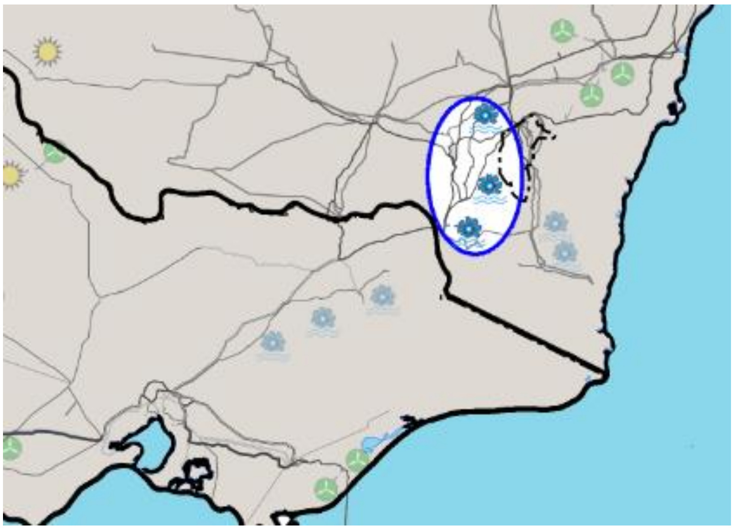
Renewable Resources	Solar	Wind	Diversity of Wind with other REZs
Resource Quality	Not applicable	Not applicable	Not studied
Potential (MW)	0	0	
Diversity	Not studied	Not studied	
Demand Matching Now 2030 2040	Not studied	Not studied	

Network Limitations	Existing	Upgraded	Network Description
Spare Network Capacity (MW)	300	-	New England REZ was identified for potential pumped hydro generation. The Armidale-Coffs Harbour 330 kV line and a number of 132 kV lines pass through this REZ. The existing network can accommodate about 300 MW of additional generation, subject to loading on the 330 kVline. The MLF decline is only moderate.
Initial Loss Factor	-	-	
Loss Factor Robustness	C	-	

Long-Term Market Simulation Scenarios	Neutral	Neutral with Storage	Slow	Fast	High DER
Generation Built (MW)	-	-	-	-	-
Timing	This REZ may could be developed in conjunction with the Northern NSW Tablelands.				

[14] NSW government. https://www.resourcesandenergy.nsw.gov.au/data/assets/pdf_file/0006/803751/NSW-Government-Submission-on-Integrated-System-Plan.pdf. Viewed 4 June 2018.

Table 33 REZ 31 – Tumut

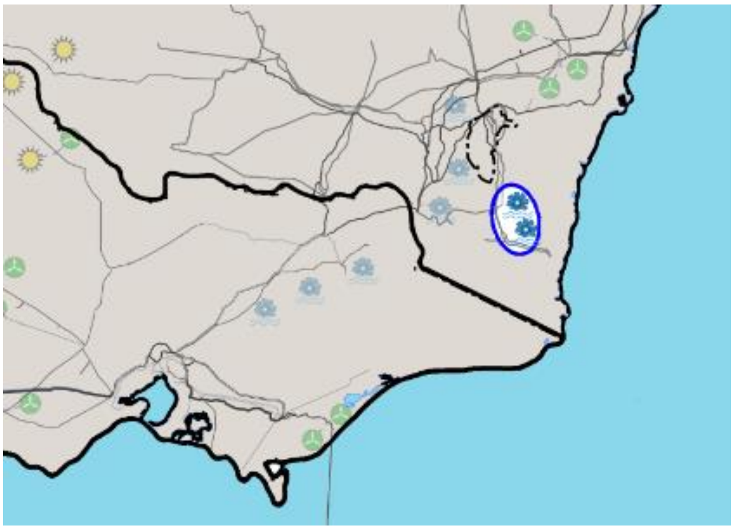
Summary	REZ Priority Level = Low
The Tumut REZ has been identified because of the potential for additional pumped hydro, such as the Snowy 2.0 project. The wind quality is also excellent.	

Renewable Resources	Solar	Wind	Diversity of Wind with other REZs
Resource Quality	Not applicable	Not applicable	Not studied
Potential (MW)	0	0	
Diversity	Not studied	Not studied	
Demand Matching Now 2030 2040	Not studied	Not studied	

Network Limitations	Existing	Upgraded	Network Description
Spare Network Capacity (MW)	0	2,000	Tumut REZ was identified for potential pumped hydro generation. The existing network cannot accommodate any large-scale generation. One proposed upgrade involves extending the 500 kV from Bannaby to Wagga to Snowy 2.0, along with the proposed Victoria-New South Wales interconnector upgrade. The MLF is extremely robust as the generation increases.
Initial Loss Factor	B	-	
Loss Factor Robustness	A	-	

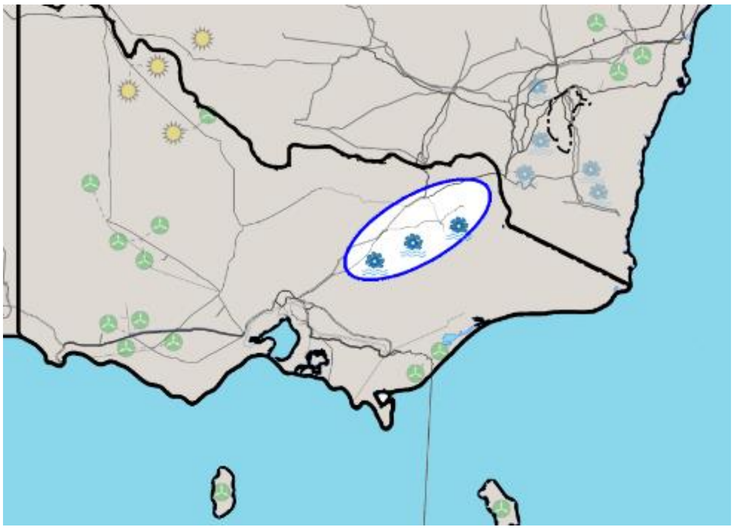
Long-Term Market Simulation Scenarios	Neutral	Neutral with Storage	Slow	Fast	High DER
Generation Built (MW)	-	2,000	-	-	-
Timing	-	2025	-	-	-

Table 34 REZ 32 – Cooma-Monaro

Summary	**REZ Priority Level = Low**
The Cooma-Monaro REZ has been identified because of its potential for additional pumped hydro. The wind quality is also excellent. There is currently a small hydro station at Brown Mountain (5 MW) and Boco Rock Wind Farm (113 MW) in service.	

Renewable Resources	**Solar**	**Wind**	**Diversity of Wind with other REZs**		
Resource Quality	Not applicable	Not applicable	Not studied		
Potential (MW)	0	0			
Diversity	Not studied	Not studied			
Demand Matching Now 2030 2040	Not studied	Not studied			
Network Limitations	**Existing**	**Upgraded**	**Network Description**		
Spare Network Capacity (MW)	200	-	Cooma-Monaro REZ was identified for potential pumped hydro generation. The existing network can only accommodate an additional 200 MW new generation. The MLF is sensitive to increased generation.		
Initial Loss Factor	A	-			
Loss Factor Robustness	E	-			
Long-Term Market Simulation Scenarios	**Neutral**	**Neutral with Storage**	**Slow**	**Fast**	**High DER**
Generation Built (MW)	-	-	-	-	-
Timing	-	-	-	-	-

Table 35 REZ 33 – Ovens Murray

Summary			**REZ Priority Level = Low**		
The Ovens Murray REZ has been identified because of its potential for additional pumped hydro. There is current 770 MW installed hydro capacity and Cherry Tree wind farm (55 MW).					
Renewable Resources	**Solar**	**Wind**	**Diversity of Wind with other REZs**		
Resource Quality	Not applicable	Not applicable	Not studied		
Potential (MW)	0	0			
Diversity	Not studied	Not studied			
Demand Matching Now 2030 2040	Not studied	Not studied			
Network Limitations	**Existing**	**Upgraded**	**Network Description**		
Spare Network Capacity (MW)	300	-	Ovens Murray REZ was identified for potential pumped hydro generation. The existing network is strong, as it is along the path of the existing Victoria-New South Wales interconnector and closer to the Melbourne load centre. The MLF is very robust as the generation increases.		
Initial Loss Factor	B	-			
Loss Factor Robustness	A	-			
Long-Term Market Simulation Scenarios	**Neutral**	**Neutral with Storage**	**Slow**	**Fast**	**High DER**
Generation Built (MW)	-	-	-	-	-
Timing	-	-	-	-	-

Appendix B. Climate change projections

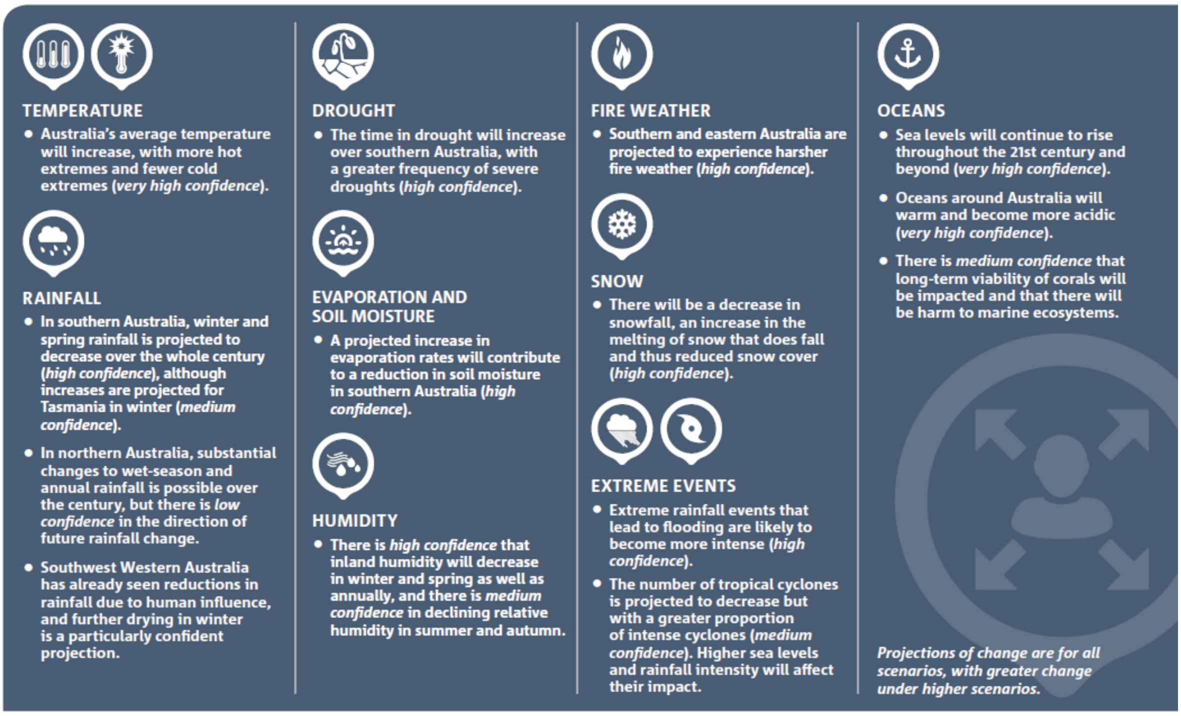
This appendix outlines key climate change projections that are expected to influence the future energy infrastructure, supply, and demand in the NEM.

Projections of long-term climate trends are sourced from the Climate Change in Australia website[15] and close collaboration with the BOM and Commonwealth Scientific and Industrial Research Organisation (CSIRO). Historical occurrences of fires in Australia were also provided by Land, Atmosphere Near Real-time Capability for EOS (LANCE) Fire Information for Resource Management System (FIRMS), operated by the NASA/GSFC/Earth Science Data on NASA's "Earthdata" website.

A summary of climate projections for Australia is provided in Figure 4. While factors such as future greenhouse gas emissions scenarios, and uncertainty in the climate response, impact the magnitude and timing of future climate change, climate scientists have high confidence in some projected changes, including changes projected for the next 20 years that are expected to eventuate due to the emissions that have already occurred.

Climate projection information at present is typically focused on changes in average climate, with limited information available on possible trends in weather extremes, which are particularly relevant to power system design. Further collaborative work in this area is progressing to better understand what this may mean for future risks to the power system.

Figure 4 Australian climate projections at a glance



From https://www.climatechangeinaustralia.gov.au/media/ccia/2.1.6/cms_page_media/176/AUSTRALIAS_CHANGING_CLIMATE_1.pd.

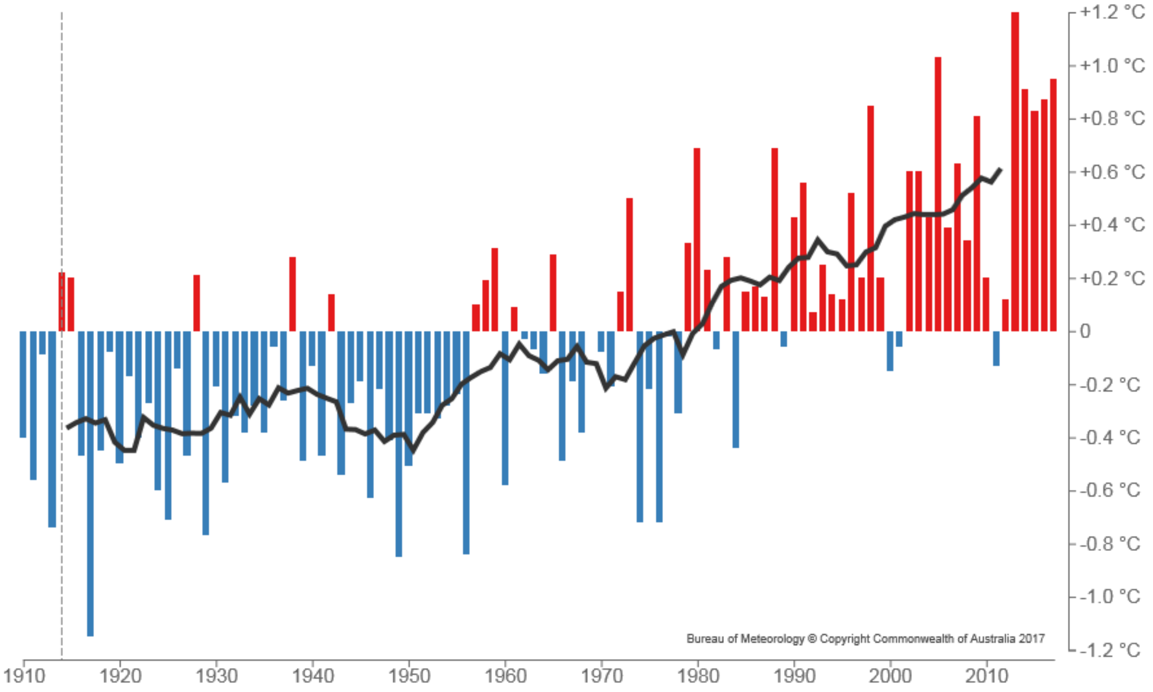
[15] BOM & CSIRO. Climate Change in Australia. Available at: https://www.climatechangeinaustralia.gov.au/en/.

B.1 Extreme temperature

The BOM has noted[16] that 2017 was Australia's third-warmest on record (see Figure 5). Australia's area-averaged mean temperature for 2017 was 0.95° Celsius (C) above the 1961-1990 average. Maximum temperatures were the second-warmest on record at 1.27°C above average, coming in behind +1.45°C in 2013. Minimum temperatures were 0.62°C above average, the 11th warmest on record.

Such years are accompanied by an increase in extreme heat days, and extreme temperature events that occur over large areas of the continent (that is, covering multiple regions simultaneously) are also increasing in frequency. During 2013, currently Australia's warmest year on record, there were 28 days on which the national daily temperature was observed above the 99th percentile for each month[17]. This compares to the period prior to 1950, when more than half the years had no such extreme days.

Figure 5 Australian mean temperature anomaly



Source: Australian Bureau of Meteorology, *Annual Climate Statement 2017*.

The 11-year mean temperature for 2007-17 was the highest on record, at 0.61°C above average (shown as the black line in Figure 5). Seven of Australia's 10 warmest years have occurred since 2005, and Australia has experienced just one cooler than average year in the last decade (2011). Background warming associated with anthropogenic climate change has seen Australian annual mean temperature increase by approximately 1.1°C since 1910. Most of this warming has occurred since 1950.

Extreme temperature projections are provided on the Climate Change in Australia website through the Thresholds Calculator[18] and provided in Figure 6. The data collected for the purposes of this section provides an indication of the projected average number of extreme temperature days per year (based on a threshold of 35°C). The left map shows the historical average while the right map shows the 2070 projected average. The comparison indicates a projected increase in extreme temperatures over the whole NEM. Multi-day heat wave events are also projected to increase in frequency and duration. While 2013 was Australia's warmest year on record, Climate Change in Australia projects that the temperatures of 2013 will represent an average year by 2030, regardless of future emissions scenarios, and a relatively cool year beyond 2050.

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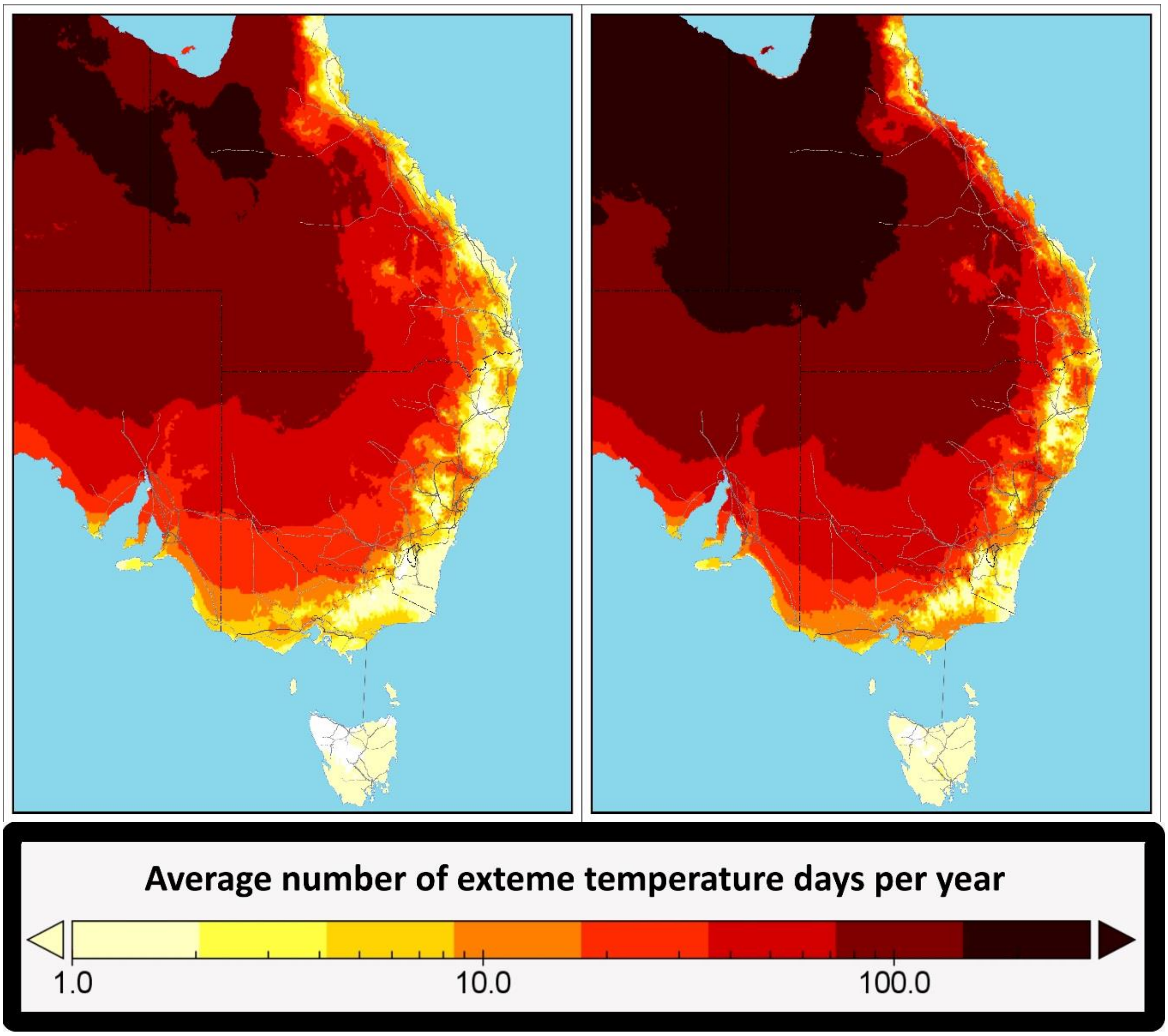
16 Australian Bureau of Meteorology. *Annual Climate Statement 2017*. Available: http://www.bom.gov.au/climate/current/annual/aus/. Note, Australian climate records commenced in 1910.

17 http://www.bom.gov.au/state-of-the-climate/australias-changing-climate.shtml

18 Climate Change in Australia. Thresholds Calculator. 2018. Available at: https://www.climatechangeinaustralia.gov.au/en/climate-projections/explore-data/threshold-calculator/

Figure 6 Extreme temperature average for 1995 (left) and projected for 2070 (right) in eastern Australia



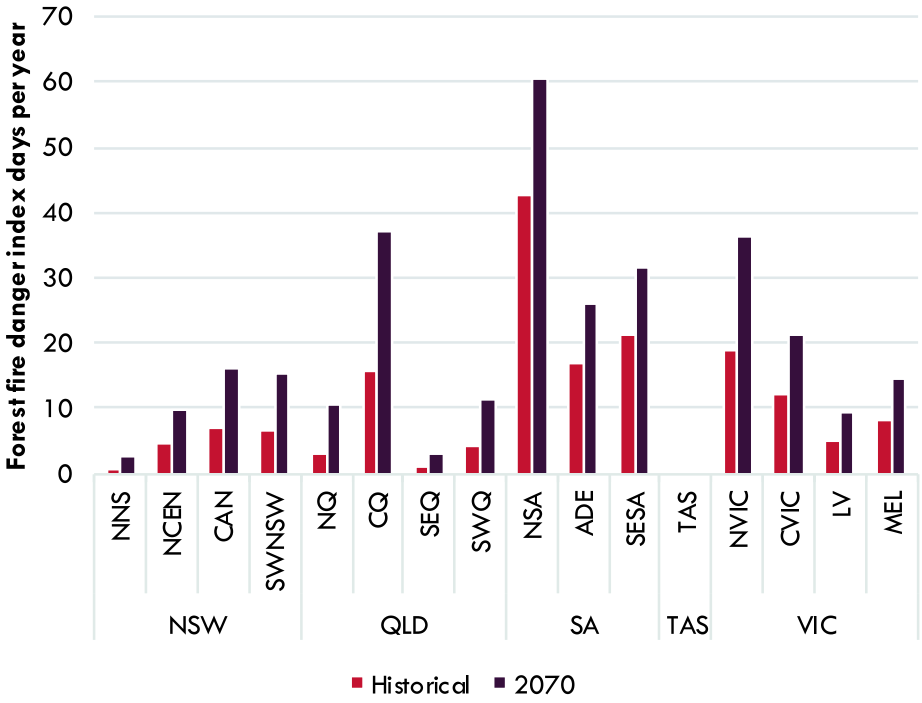
The power system is designed and planned for the extremes of operating temperatures for the life of the assets. For transmission and generation infrastructure, this can be as long as 40 to 80 years. The projected extreme temperature days from the Climate Change in Australia website show a large relative increase in 2070 compared to current, with some areas which have seen one or two extreme days per year projected to see 10 or more. Others which have seen 20 extreme days per year may see more than 40. Many of these days could be in consecutive sets, increasing and prolonging the stress on the power system. Resultant thermal constraints on power system infrastructure, imposed to avoid permanent damage, may lead to more constraints on power system operation.

Figure 7 shows the absolute projected increase in extreme temperature days in each planning zone. Red represents historical data, and blue represents data for the 2070 projection. These planning zones have been used by AEMO in previous analysis on the development of the power system in previous National Transmission Network Development Plans (NTNDPs), and are outlined on AEMO's Interactive Map[19].

It is evident that South Australia and Victoria already experience a high frequency of extreme temperature days while a significant relative increase in extreme temperature days is expected in other regions. Forecast changes include extension of current summertime conditions into spring and autumn at most locations. However, the NTNDP planning zones cover wide areas where weather and climate can vary considerably, and each connection point should be considered independently.

[19] AEMO. Interactive Map. 2018. Available at: http://www.aemo.com.au/aemo/apps/visualisations/map.html

Figure 7 Average extreme temperature increase by NTNDP planning zone and region



Implications for future power system operation and planning

Many lines and switchgear currently in the NEM were designed for lower operating temperatures than those being projected by BOM and CSIRO for future decades. Higher temperatures can result in the need to operate infrastructure at lower capacity to protect against damage or failure.

The projected increases in temperatures and duration and frequency of heat events could lead to the following:

- Increasing temperatures leading to very hot and humid days in multiple regions of the NEM would be expected to lead to increased demand for electricity (driven by population growth and increased cooling needs), and could result in much higher demand peaks in individual years.
- Prolonged heatwaves could increase the stress on the power system assets themselves, resulting in increases in individual equipment failures, particularly in older equipment.
- During these periods, output of thermal and renewable generation is expected to decrease, and transmission line capabilities would be reduced, as the assets are de-rated in higher temperatures.
- During these periods, the risk of bushfires could also be increased, potentially impacting system availability or capacity.

The following examples demonstrate the reduction in capability of specific types of generation and network assets:

- **Thermal generation** – in a report to the Independent Market Operator (now AEMO), Sinclair Knight Merz (now Jacobs) outlined that typical gas turbines begin to de-rate at 35°C and can de-rate as much as 5% and 8% for ambient temperatures of 40°C and 45°C, respectively[20].
- **Solar farms** – some utility power system inverters de-rate around 10% when operating at 50°C. Inverters operating in the distribution network can also de-rate by 10% or more at 50°C.
- **Wind farms** – typical wind farm turbines in the NEM experience 100% de-rating for temperatures between 35°C and 45°C, and will return to service when the temperature drops around 1°C to 5°C from the cut-out temperature.

[20] SKM. *Advice on Power Factor and Accuracy of Temperature Dependent Outputs*, 3 September 2009, available at https://www.aemo.com.au/media/docs/default-source/rules/commenced/pc_2010_06skm_report_on_load_factor_and_heat_rate_advicef6a0.pdf?sfvrsn=0.

- **Transmission lines** – short-term transfer capability can be reduced up to 14% for a temperature increase from 35°C to 40°C. For 500 kV lines, this reduction can be as high as 250 MW. Conductors expand at high temperatures, and at extreme temperatures are at risk of irreversible expansion[21], resulting in permanent reduced capability.
- **Power electronics** – the Basslink DC interconnector between Victoria and Tasmania automatically limits capacity progressively when ambient temperatures at Loy Yang reach 43°C or above, or when temperatures at George Town reach 33°C or above, to protect the link against excessive temperature rise.[22]

All these factors suggest the need for future equipment capabilities to be designed to higher maximum temperatures, especially for any associated cooling systems.

B.2 Rainfall, humidity, and runoff projections

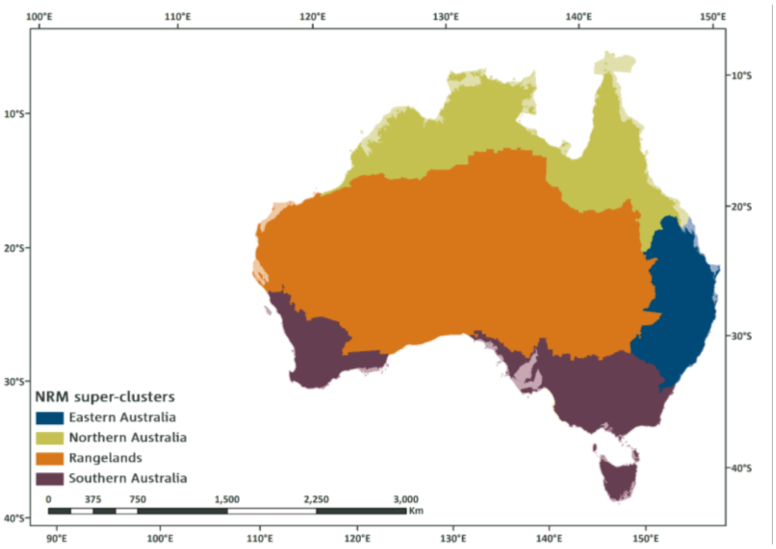
The BOM's *State of the Climate 2016*[23] report outlines a number of important observations related to projections of rainfall, humidity, and possible consequences of relevance to the NEM.

According to the BOM:

- The south-east of Australia has experienced declines in rainfall in recent decades. The declines have occurred in the period from April-October, which is historically the rainfall season in the south.
- In the south-east, rainfall has declined by around 11% since 1996, and six of the 20 years from 1997 recorded below-average rainfall. This change is amplified in reduced runoff, and with the south-east experiencing stream flows around 50% of the long-term average. The reduced rainfall has been accompanied by lower atmospheric humidity and higher temperatures, contributing to an increase in bushfire risk.
- While rainfall in Australia is highly variable, the trends in the south-east are discernible from background variability. Studies indicate that the recent rainfall declines could continue in the future.

Projections from the Climate Change in Australia website[24] are provided with varying degrees of confidence for four major climate regions known as "super-clusters", with some analysis also available for smaller regions throughout Australia. Figure 8 defines these super-clusters – southern Australia includes Victoria, South Australia, New South Wales, and Tasmania, and eastern Australia includes parts of New South Wales and Queensland.

Figure 8 Climate change projections regionalisation scheme



CSIRO and BOM. Climate Change in Australia. Regionalisation Schemes. 2016. Available at: https://www.climatechangeinaustralia.gov.au/en/climate-projections/about/modelling-choices-and-methodology/regionalisation-schemes/

[21] Irreversible expansion is a result of the annealing process where the conductor is heated to a high temperature and slowly cooled. Transmission lines heat up as more energy flows, and, when combined with high ambient temperatures, they may begin to sag. Transmission lines may be damaged if allowed to become too hot for too long, and if allowed to sag, they could breach minimum safety clearances.

[22] Basslink. Operations. 2018, available at http://www.basslink.com.au/basslink-interconnector/operations/.

[23] BOM and CSIRO, *State of the Climate 2016*, available at http://www.bom.gov.au/state-of-the-climate/australias-changing-climate.shtml.

[24] CSIRO and BOM. Projections for Australia's NRM Regions. Climate Change in Australia. 2016. Available at https://www.climatechangeinaustralia.gov.au/en/climate-projections/future-climate/regional-climate-change-explorer/super-clusters/?current=SSC&tooltip=true&popup=true.

While the magnitude and timing of future rainfall changes are subject to uncertainty, there are some projections that can be stated with greater likelihood.

- The majority of climate models project rainfall declines over southern and eastern Australia this century.
- Streamflow is projected to decline across Victoria, and the south-east generally, regardless of the seasonality and magnitude of future rainfall declines, as temperatures increase and relative humidity declines.
- The frequency of extreme high rainfall events and high atmospheric moisture events are expected to increase, even across regions that will experience an overall decline in average rainfall.

Table 36 outlines the key projections for rainfall, humidity, and runoff specific to eastern and southern Australian super-clusters.

Table 36 Key climate projections for rainfall, humidity, and runoff

Climate factor	Super-cluster	Projection
Rainfall	Southern Australia	A continuation of the trend of decreasing winter rainfall with high confidence. Spring rainfall declines with high confidence.
	Eastern Australia	Decline in average winter and spring rainfall with medium confidence.
Humidity	Southern & eastern Australia	Decline in relative humidity in regions where rainfall is projected to decline. High confidence that relative humidity will decline in winter and spring and medium confidence relative humidity will decline in summer and autumn. Medium confidence rain runoff will decline in far-southeast Australia.
Runoff	Southern Australia	Decline in runoff for southern South Australia with high confidence.
	Southern & eastern Australia	Decline in runoff for far south–eastern Australia.

Implications for future power system operation and planning

Rainfall provides the water necessary for the operation of hydro generation and the cooling of coal-fired generation.

AEMO's 2018 *Energy Adequacy Assessment Projection* (EAAP)[25] assessed the impact of energy constraints on supply adequacy in the NEM across a two–year period. One potential constraint considered in the EAAP is the water available as cooling water for thermal generation during drought conditions.

The EAAP highlighted that, if sufficient cooling water is not available under low rainfall conditions, there is an increased risk of supply interruption. Further, the 2018 *Gas Statement of Opportunities* highlighted that demand for gas-powered generation (GPG) increases under drought conditions, tightening a finely balanced gas demand-supply situation.

Drought conditions may therefore impact hydro-, coal-, and gas-fired generation availability, and consequently power system reliability.

The projections indicate a number of potential areas of importance for future requirements for reliability. AEMO will continue to work with CSIRO and BOM to better understand the potential for future risks to reliability.

B.3 Bushfires

Figure 9 below provides a historical indication of large bushfire frequency in NEM regions[26].

Figure 10 illustrates fire activity in NEM regions between late 2000 and early 2018, showing fire activity around transmission assets in eastern Victoria and southern Queensland. Presently, many major transmission interconnections and associated critical electrical infrastructure linking key regions in the NEM run through heavily bushed or grass plain areas that have already been subject to major fires. The transmission and distribution networks in Queensland, New South Wales, Victoria, and Tasmania have all experienced moderate bushfire activity.

[25] AEMO. 2018. Energy Adequacy Assessment Projection. Available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/EAAP/2018/2018-ENERGY-ADEQUACY-ASSESSMENT-PROJECTION.PDF

[26] CSIRO. Bushfires 'down under': patterns and implications of contemporary Australian landscape burning. 2007. Available at: http://www.southwestnrm.org.au/sites/default/files/uploads/ihub/russell-smith-j-etal-2007bushfires-down-under-patterns-and.pdf.

Figure 9 Historical occurrence of large bushfires in Australia

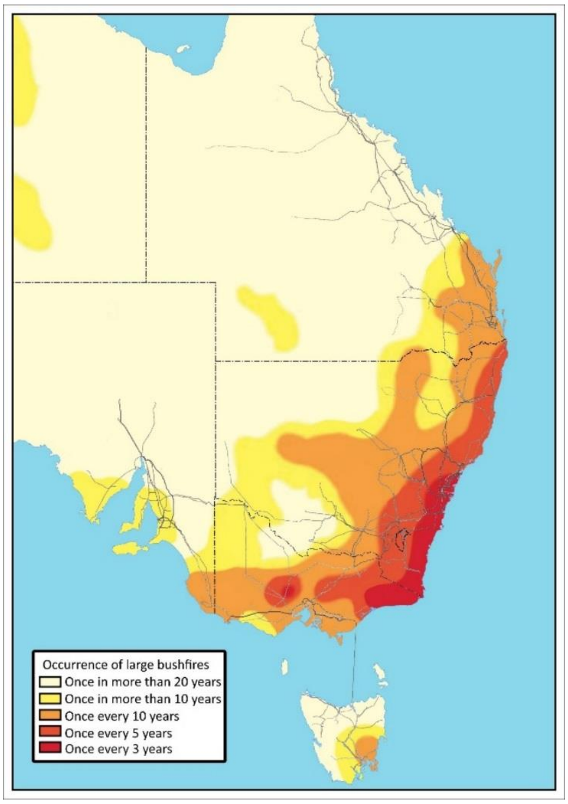
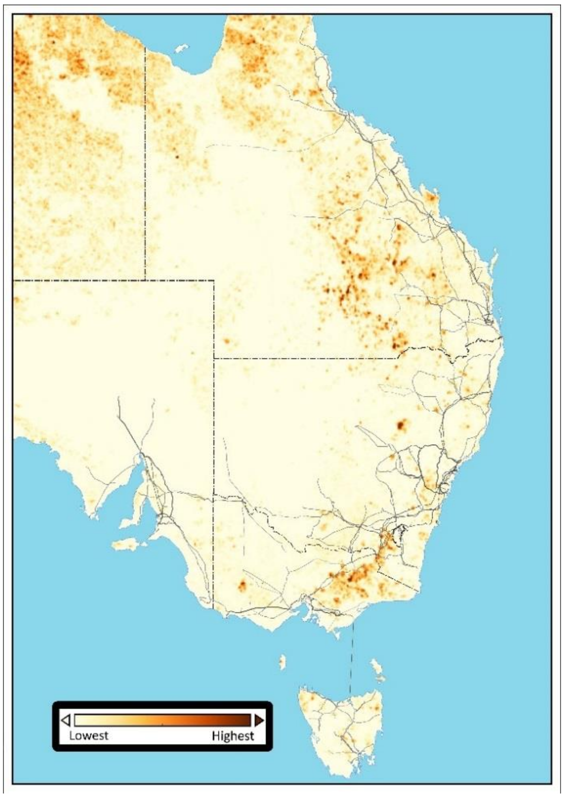


Figure 10 Fire detection between November 2000 and May 2018[A]



A. The data behind this figure was developed from information provided by LANCE FIRMS, operated by the NASA/GSFC/Earth Science Data on NASA's Earthdata website. The data represents Collection 6 Terra and Aqua Moderate Resolution Imaging Spectrometer (MODIS) fire product at 90% confidence.

The *State of the Climate 2016* report by the BOM outlined that in future, southern and eastern Australia are projected to experience more days conducive to fire[27]. Additionally, fire weather conditions have already become more severe, and the fire season prolonged, particularly in many parts of southern and eastern Australia. More extreme heat events are expected to contribute to this fire danger. The lengthened fire season is already having an impact on bushfire mitigation, power system operation, and vegetation management practices, and has potential implications for the management of power transmission network.

The Forest Fire Danger Index (FFDI) captures the ability of a fire to spread. This measure uses temperature, relative humidity, and wind speed as direct inputs into its calculation[28]. An additional input is the drought factor, which indicates the available fuel's readiness to burn. It is possible to project future FFDI given projections of temperature, relative humidity, and wind speed. The Climate Change in Australia website[29] provides a Fire Summary Data set which includes historical threshold Forest Fire Danger Index (FFDI) data for 39 weather stations in Australia and projections based on three climate models. The data counts the average days per year the FFDI category is High, Very High, Extreme, or Catastrophic. For the purposes of this analysis, if a day is not included in any of these categories it is considered a low-risk day. Any day which is categorised into High, Very High, Extreme, or Catastrophic is a high-risk day.

The two figures below show the historical (left) and 2070 projection (right) proportion of days in a year where the FFDI is categorised high (dark purple) or low (pink). For each NTNDP planning zone, the closest weather station was assigned. For example, Moree's station data was assigned to the Northern New South Wales (NNS). In an average year, the FFDI is at least high or greater 4% of the time. This is projected to increase to 81% of the time in 2070. For some zones, like Melbourne (MEL) and Adelaide (ADE), there is a projected decrease.

Figure 11 Historical (left) and 2070 projected (right) annual fire risk by NTNDP zone

Implications for future power system operation and planning

Preparing for bushfires will be an important consideration when planning the future power system. It is a common misconception that fires need to burn down power poles to impact the power system. Flashovers initiated by smoke are the most frequent cause of transmission line outages during bushfires. Operationally, parallel double-circuit lines can be impacted by the same fire, and are managed as a single credible contingency when bushfires are nearby.

As shown in Table 37, bushfires have led to the majority of NEM regional separation events in recent history. Bushfires can lead to disconnection or de-rating the transmission network, potentially constraining the supply of electricity to consumers in significant ways.

[27] BOM. State of the Climate 2016. Available at: http://www.bom.gov.au/state-of-the-climate/State-of-the-Climate-2016.pdf

[28] Climate Change in Australia, Technical Report page 139. Available at: https://www.climatechangeinaustralia.gov.au/media/ccia/2.1.6/cms_page_media/168/CCIA_2015_NRM_TR_Chapter%207.pdf

[29] Climate Change in Australia. Thresholds Calculator. 2018. Available at: https://www.climatechangeinaustralia.gov.au/en/climate-projections/explore-data/data-download/station-data-download/

Table 37 Separation events

Date	Event
28 September 2016	Storms and destructive winds: The South Australia power system experienced frequency collapse and total system black during severe storms and a series of tornadoes with wind speeds in the range of 190 to 260 km/h.
23 February 2015	Bushfire: Trip of the Basslink interconnector and the 220 kV Gordon – Chapel Street No. 2 line due to lightning and fires.
8 February 2009	Bushfire: The Dederang – Shepparton 220 kV line and the Buronga – Balranald 220 kV line tripped during bushfires and lightning in the vicinity. This resulted in the separation of Victoria from New South Wales, because the Dederang – South Morang 330 kV lines, Dederang –Glenrowan 220 kV lines, and Eildon – Thomastown 220 kV line were already out of service due to bushfire-related faults.
16 January 2007	Bushfire: Separation of New South Wales, Victoria, and South Australia due to cascade tripping of transmission lines. The initiating incident was a trip of the Dederang – South Morang 330 kV lines due to bushfires.
5 October 2002 - 2 February 2003	Bushfire: Fires caused 201 outages of TransGrid's 330 kV and 500 kV transmission lines, including 103 trips with auto-reclose and two at the request of the Bushfire service for emergency operations[30].
20 October 2002	Bushfire: Fires caused the trip of Dumaresq – Bulli Creek 330 kV lines, isolating Queensland from New South Wales.
21 April 1993 and 31 January 1996	Bushfire: The Heywood Interconnector tripped between Tailem Bend and Para due to fires in South Australia.

The choice of pathways for critical transmission will be important. Using existing easements for transmission development could have a lower capital cost, but result in a national transmission network that is less able to manage future bushfire risk. Diversification of transmission corridors, particularly for high transfer assets such as interconnectors, could reduce the risk of bushfires limiting transfer capability at key times or of state separation.

As an example, the South Morang to Dederang to Murray transmission lines, located in the direct path between the Snowy Mountains and Melbourne, provide a key power sharing interconnection between Victoria and New South Wales:

- Figure 10 shows there has been high occurrence of bushfires near these lines, due to the forested areas through which the transmission corridor passes.
- Future transmission development between New South Wales and Victoria would benefit from a diverse corridor being established to ensure a resilient transmission network and reduce the chance of cascading events.
- The proposed SnowyLink interconnection would provide diversification of the transmission network between Victoria and New South Wales, further reinforcing the network and reducing the possible impacts of future bushfires on the power system.

B.4 Wind speed

With increasing wind generation in the NEM, wind patterns are expected to become increasingly important to power system planning and will influence investment location for future renewable generation sources.

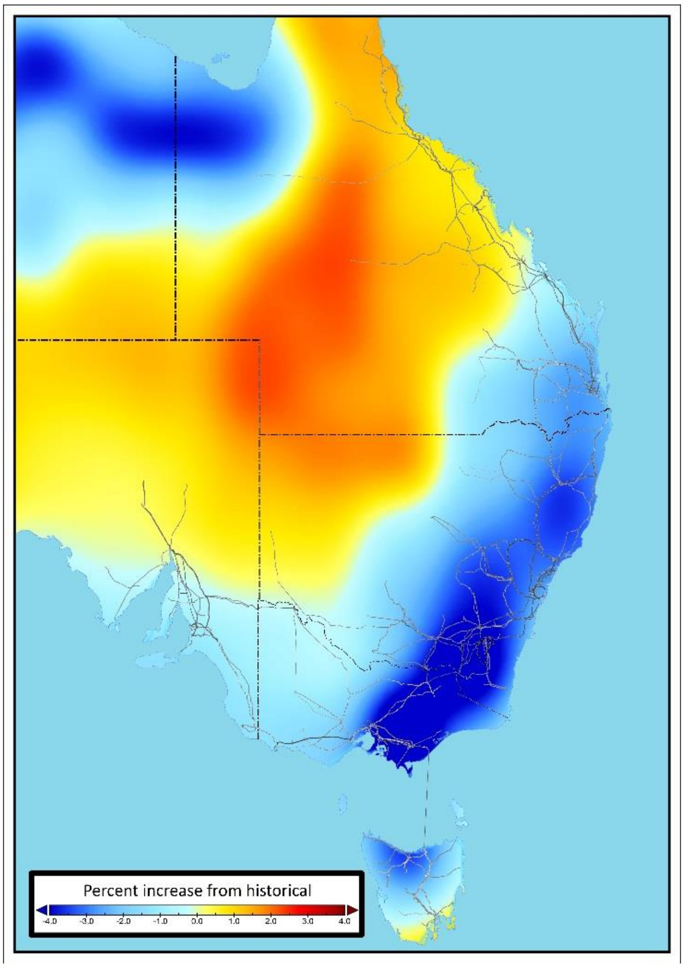
Figure 12 provides an indication of changing average wind speed in eastern Australia from the historical average. The data behind the figure is an average of eight core models available on the Climate Change in Australia website[31].

Eastern coastal regions are expected to see a small relative decrease in average wind speeds while north Queensland is expected to see a small relative increase in average wind speeds. This figure does not illustrate changing patterns of extreme wind gusts, noting considerable uncertainties around projected changes in future extreme wind gusts in Australia. This is due to the relatively small-scale modelling required to represent the physical processes associated with wind gusts, which currently available climate models are not able to do with a high degree of confidence. This is particularly relevant to the modelling of convective systems (including thunderstorms) that can cause extreme wind gusts. AEMO and the BOM are considering collaboration to evolve the modelling to address these emerging power system planning requirements.

[30] TransGrid. Annual Report 2003, available at https://www.opengov.nsw.gov.au/download/11958.

[31] Climate Change in Australia, Map Explorer. 2018. Available at: https://www.climatechangeinaustralia.gov.au/en/climate-projections/explore-data/map-explorer/

Figure 12 Average wind speed change as a percentage of historical average wind speed



Implications for future power system operation and planning

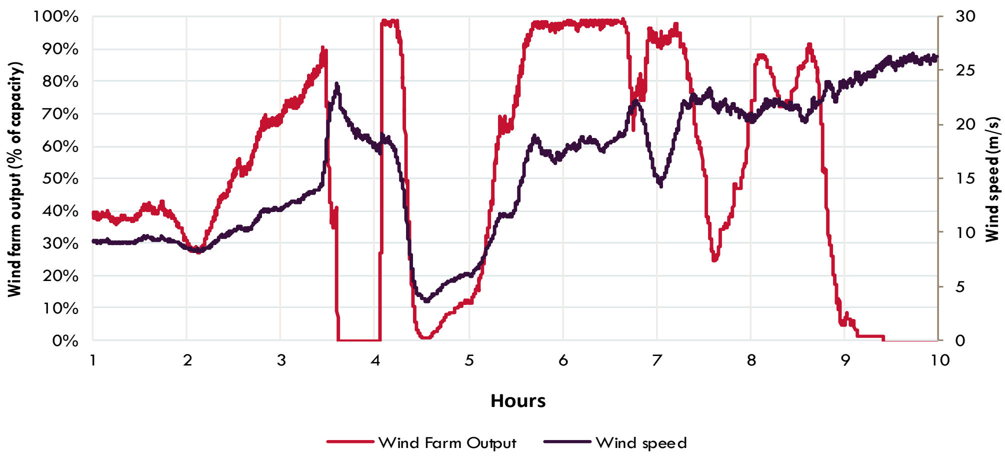
Wind generation

With increasing development of wind generation, wind patterns are becoming increasingly important to power system planning.

While moderate winds increase wind farm output, extreme winds can limit wind farm output. Wind turbines can experience high speed cut-out when they are subject to wind speeds of more than 20 m/s to 32 m/s (dependent on the design). They typically return to service once the wind speed reduces from the cut-out speed by between 1 m/s and 12 m/s.

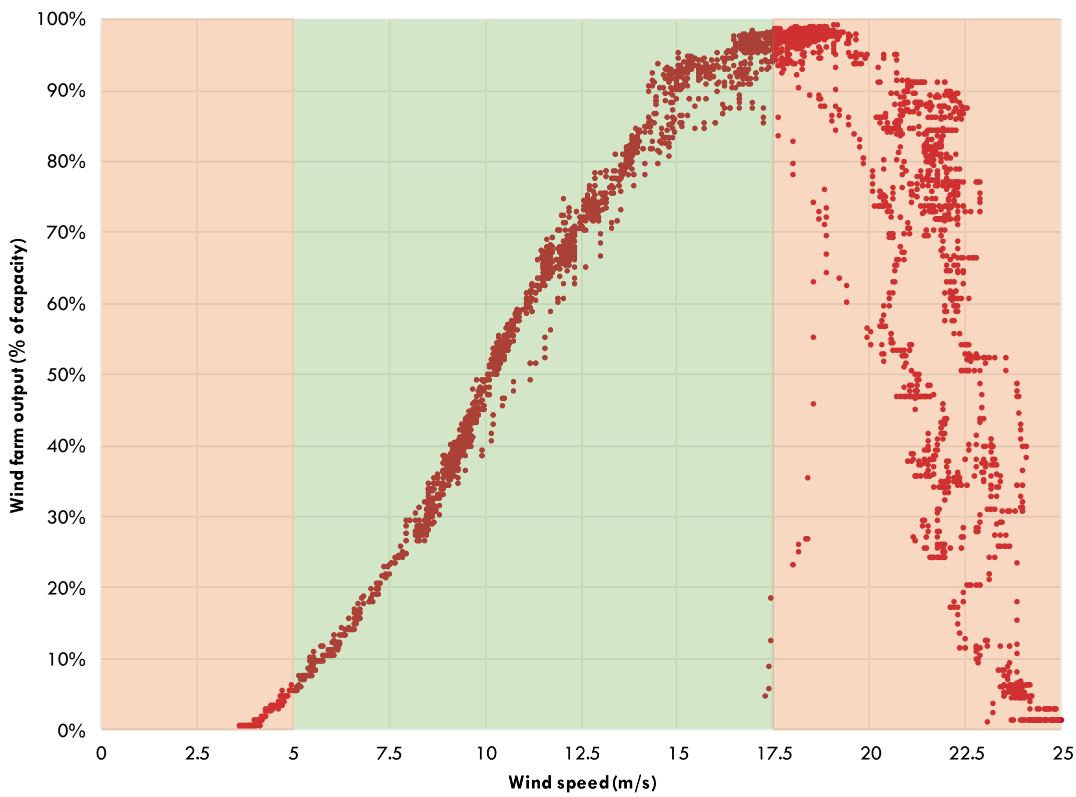
Figure 13 provides an example of how extreme winds can cause output to vary in a wind farm. If a large number of wind farms are clustered in a REZ, potentially experiencing similar wind conditions, this effect can be amplified. This emphasises the need for greater diversity, storage, or access to other sources, to smooth the impact of variations on total dispatch.

Figure 13 Example of high wind speed cut-out and generation ramping during extreme winds



For indicative purposes, Figure 14 below shows the output of a typical NEM wind farm measured by AEMO's Energy Management System (EMS) during a period of turbulent weather under otherwise typical conditions. In this case, wind speed varied between very low (5 m/s) to very high (25m/s). The green area indicates where the wind speed is moderate and the wind farm output is predictable. The red area on the right shows high wind speed and the resultant variability of the wind farm output. This shows how some wind farms, depending on their design, can experience high wind speed cut-out and cut-in multiple times over a nine-hour period.

Figure 14 An example of wind farm cut-out and cut-in speeds



Transmission

Operationally, AEMO considers the heightened risk that high wind speeds pose to nearby transmission lines when wind speeds are forecast to exceed transmission line and tower design ratings. It is important to understand and consider these factors in planning the future power system. This is covered under Australian Standards AS 3995 and AS 7000, where the Standards prescribe a process for determining the importance of each line/tower which in turn determines the overall design.

For example, the transmission easements along the North Queensland coast are more exposed to tropical cyclones when they make landfall. Transmission lines which share easements are more at risk of experiencing coincident trips. In its 2017 Transmission Annual Planning Report (TAPR), Powerlink noted that flood risk associated with Tropical Cyclone Debbie caused collapse and damage to 19 towers on one of the 275 kV single circuit lines between Broadsound and Nebo[32].

When cyclones pose an imminent risk to the power system, AEMO takes operational action to mitigate the impact of transmission line failure (for example, by reducing power transfer between north and central Queensland). The following table provides recent examples of the impacts of cyclones on the transmission network.

Table 38 Recent cyclones that affected the Queensland transmission network

Event	Description
Tropical Cyclone Debbie	On 28 March 2017, Tropical Cyclone Debbie (Category 4) crossed the Queensland coast between Bowen and Proserpine and continued inland in a south-west direction. AEMO reclassified the loss of multiple transmission lines to maintain the power system in a secure operating state (Ross limit). No load was interrupted in the transmission system due to faults on the transmission network, however, in the distribution network, Ergon reported power was cut to 65,000 customers[33].
Tropical Cyclone Marcia	On 20 February 2015, Tropical Cyclone Marcia posed a risk to power system security. In response, AEMO reclassified the loss of multiple transmission lines between Bouldercombe and Nebo as a credible contingency event, and directed Northern Queensland generation to maximum output. As outlined in AEMO's NEM Event report[34], there was no load shedding in central and northern Queensland. This would not have been the case had AEMO not issued these directions and the reclassified lines tripped.
Tropical Cyclone Yasi	On Thursday 3 February 2011, Tropical Cyclone Yasi (Category 5) crossed the north Queensland coast. As a result of damage wrought by the cyclone twelve 132 kV transmission lines tripped out of service, and four 132 kV bulk supply substations and one power station were automatically disconnected from the power system. Restoration of the high voltage transmission network began at 10.49 am on 3 February 2011 and was completed on 11 February 2011. The power system remained in a secure operating state for the duration of the incident[35].

[32] Powerlink. 2017 Transmission Annual Planning Report. Available at: https://www.powerlink.com.au/reports/transmission-annual-planning-report-2017.

[33] Ergon, "Tropical Cyclone Debbie sparks hi-tech response", 10 April, 2017, at https://www.ergon.com.au/about-us/news-hub/talking-energy-blog/technology/tropial-cyclone-debbie-sparks-hi-tech-response.

[34] AEMO, *NEM Event – Directions to Northern Queensland generators during Tropical Cyclone Marcia – 20 February 2015*, published May 2015. Available at https://www.aemo.com.au/media/Files/Other/reports/NEM%20Event%20%20Directions%20to%20Nth%20Queensland%20Gens%20%2020%20February%202015.pdf.

[35] AEMO. *Power System Incident Report: Tropical Cyclone Yasi – 2 and 3 February 2011*. Available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2011/0232-0092-pdf.pdf.

Appendix C. Network Support and Control Ancillary Services (NSCAS)

NSCAS[36] are non-market ancillary services that may be procured by TNSPs (or by AEMO as a last resort) to maintain power system security and reliability, and to maintain or increase the power transfer capability of the transmission network.

There are currently three types of NSCAS:

- **Network Loading Ancillary Service (NLAS)** – maintains power flow in transmission lines within capacity ratings following a credible contingency event; and maintains or increases the power transfer capability of that transmission network, by allowing increased loading on transmission network components.
- **Voltage Control Ancillary Service (VCAS)** – maintains the transmission network within voltage stability limits, and maintains or increases the power transfer capability of that transmission network, by improving voltage control and voltage stability.
- **Transient and Oscillatory Stability Ancillary Service (TOSAS)** – controls power flow into or out of the transmission network, to maintain the transmission network within its transient or oscillatory stability limits, and maintains or increases the power transfer capability of that transmission network, by improving transient or oscillatory stability.

AEMO has undertaken an assessment of system security over the coming five-year period, and has identified no new NSCAS gaps.

C.1 NSCAS gaps for maintaining power system security

The following sections present the outcomes from the 2018 NSCAS assessments.

C.1.1 New South Wales

AEMO has worked with TransGrid to implement new voltage limits, and operational measures to mitigate the need for NSCAS in New South Wales. As a result of this collaboration, no NSCAS gap for maintaining power system security is projected in New South Wales over the five-year outlook period.

C.1.2 Queensland

South East Queensland may experience transmission line overloads or high bus voltages during certain operating conditions. These issues can be managed by line switching. Therefore, no NSCAS gap for maintaining power system security is projected in Queensland over the five-year outlook period.

[36] NSCAS information, procedures, and guidelines are available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Securityand-reliability/Ancillary-services/Network-support-and-control-ancillary-services-procedures-and-guidelines.

C.1.3 South Australia

AEMO identified an NSCAS gap in South Australia for system strength in the 2016 NTNDP[37], and confirmed this gap in subsequent updates in September 2017[38] and October 2017[39].

ElectraNet has elected to treat this NSCAS gap as a 'fault level shortfall' under the transitional arrangements for the Australian Energy Market Commission's (AEMC's) managing power system fault levels rule change determination[40].

In addition to the system strength gap, the South Australian transmission network may experience high voltages during light load conditions. AEMO's assessment has not identified an NSCAS gap over the next five years, as voltages can be sufficiently managed within acceptable limits if:

- Synchronous generation is dispatched in line with AEMO's minimum system strength requirements, as outlined in Section 5.4.2.
- Current operational switching of the 275 kV Magill – East Terrace cable is utilised to manage high voltages during light load conditions continues.
- ElectraNet installs synchronous condensers or two new reactors in the 275 kV network over the next five years, as proposed in their 2017 TAPR[41].

C.1.4 Tasmania

The Tasmanian network can experience low system inertia, and difficulty with voltage control around the George Town area. Currently, system inertia is maintained at secure levels using a constraint equation that manages the Tasmanian generation mix and Basslink transfer levels. Voltage control can be managed using control schemes, voluntary generator dispatch from Hydro Tasmania, or by constraining Basslink transfer levels. TasNetworks installed a 40 MVAr capacitor bank at George Town 110 kV in March 2018. In addition, TasNetworks has a proposal to install +/-50 MVAr STATCOM in Georgetown area driven by market benefits of Basslink export constraints.

With the existing operational measures in place and additional reactive support, no NSCAS gap for maintaining power system security is forecast in Tasmania over the five-year outlook period.

C.1.5 Victoria

Under low demand conditions, over-voltages can occur in Victoria as a result of credible contingencies. Temporary operational measures, such as line switching, have been applied during periods of low demand to maintain voltages within operating limits. AEMO has initiated a Victorian Reactive Power Support Regulatory Investment Test for Transmission (RIT-T) to identify a preferred option to manage voltages in Victoria. Further information can be found in the RIT-T Project Specification Consultation Report (PSCR)[42]. No NSCAS gap for maintaining power system security is forecast to occur in Victoria over the five-year outlook period, while these operational measures of line switching are available.

C.2 NSCAS gaps for maximising market benefits

AEMO has assessed historical binding constraint data, and considers that there are insufficient benefits to NEM consumers from addressing constraints using NSCAS at this time. AEMO will review constraint binding data and the need for NSCAS to maximise market benefits over the coming year.

C.3 Status of NSCAS gaps identified in previous NTNDPs

AEMO procured two VCASs but did not procure any NLAS or TOSAS for the 2017-18 financial year. The table below shows the costs for NSCAS services procured between the 2013-14 and 2017-18 financial years.

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[37] The 2016 National Transmission Network Development Plan: http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NTNDP/2016/Dec/2016-NATIONAL-TRANSMISSION-NETWORK-DEVELOPMENT-PLAN.pdf

[38] Update to the 2016 National Transmission Network Development Plan: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NTNDP/2017/2016-NATIONAL-TRANSMISSION-NETWORK-DEVELOPMENT-PLAN.pdf

[39] Second update to the 2016 National Transmission Network Development Plan: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NTNDP/2017/Second_Update_to_the_2016_NTNDP.pdf

[40] AEMC managing power system fault levels: http://www.aemc.gov.au/Rule-Changes/Managing-power-system-fault-levels

[41] South Australian Transmission Annual Planning Report June 2017: https://www.electranet.com.au/wp-content/uploads/2017/06/2017-Transmission-Annual-Planning-Report.pdf

[42] Victorian Reactive Power Support, May 2018, http://aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2018/Victorian-reactive-power-support-RIT-T-PSCR.pdf

Table 39 NSCAS services and costs from 2014 to 2018

Facility	Benefitting region	NSCAS Service	Quantity (MVAr)	Annual Cost				
				2013-14	2014-15	2015-16	2016-17	2017-18
Combined Murray and Yass substations	NSW	VCAS	800	$3,195,62	$9,896,698	$10,055,572	$10,159,498	$10,375,519
Combined Murray and Tumut power stations	NSW	VCAS	700	$41,301,706	$134,494	$171,797	$147,088	$3,842,236
Total				$44,497,327	$10,031,191	$10,227,368	$10,306,586	$14,217,755

C.3.1 Agreement with TransGrid for reactive support at Murray and Yass substations

AEMO has procured 800 MVAr absorbing VCAS from TransGrid, primarily using new network assets, including reactors at Murray Switching Station and Yass Substation. Provision of full VCAS service under this agreement commenced from 31 March 2014 and will end by 30 June 2019. TransGrid is expected to include the relevant network assets in its regulated asset base, and continue to provide the required voltage absorbing capability as a prescribed transmission service, after the expiry of this agreement.

VCAS costs are based on the availability of TransGrid's NSCAS equipment at a fixed cost per trading interval, regardless of usage.

C.3.2 Agreement for generation support at Murray and Tumut power stations

AEMO had an NSCAS agreement for the provision of VCAS by generation units running as synchronous condensers from 1 July 2013 to 30 June 2018. This service provided both absorbing and supplying reactive power as a bundled reactive capability. AEMO, in collaboration with TransGrid, identified and implemented operational solutions to mitigate the need for this service.

Appendix D. Detailed transmission network development requirements

D.1 Interconnector upgrade details

This section outlines the details of the individual interconnector upgrades which have been identified under the ISP network development plans. Further detail is available in the ISP Assumptions workbook[43].

D.1.1 Staged upgrades between Queensland and New South Wales

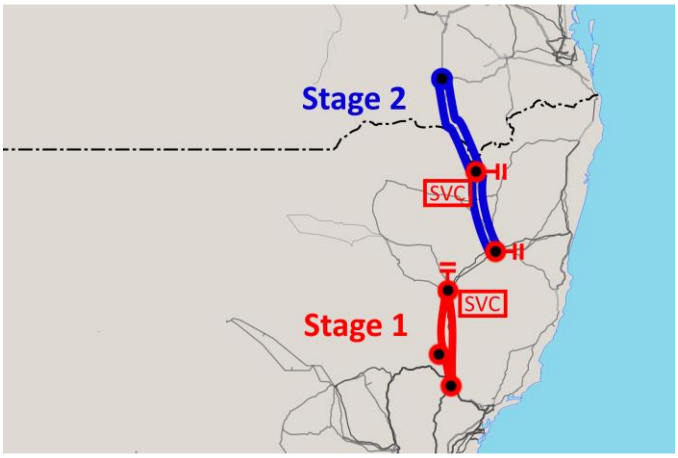
In the ISP, AEMO has recommended:

- A minor upgrade to provide additional transfer capacity to New South Wales from Queensland prior to the closure of Liddell Power Station in 2022.
- A medium to large upgrade of the New South Wales – Queensland interconnector in the early to mid-2020s (depending on planning approvals and construction timelines) to increase transfer capability as generation connects to support the QRET and to improve reliability.

The developments will provide additional capacity for connection of renewable generation in each state, as described in more detail in Appendix B of the ISP.

Figure 15 shows the major components of these upgrades – the minor upgrade is shown in red and the medium upgrade in blue.

Figure 15 New South Wales to Queensland interconnector upgrades



[43] AEMO. *Integrated System Plan Assumptions Workbook*, June 2018, available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan.

Phase 1 – Upgrade the existing corridor

The first stage upgrade being considered for the New South Wales to Queensland interconnector makes use of existing transmission lines by:

- Uprating[44] of Liddell–Muswellbrook 330 kV line.
- Uprating of Muswellbrook–Tamworth 330 kV line.
- Uprating of Liddell–Tamworth 330 kV lines.
- Installing static VAR compensators (SVCs) at Dumaresq and Tamworth substations.
- Installing shunt capacitor banks at Tamworth, Armidale, and Dumaresq substations.

This project is expected to increase the transfer capacity towards New South Wales by 190 MW, and towards Queensland by approximately 460 MW, increasing system flexibility and allowing more efficient sharing of generation resources between these regions. The estimated cost of this upgrade is $142 million. This option is considered a first stage because it can be delivered sooner than the option to establish a new corridor, and is expected to be able to be in service by 2020.

Phase 2 – Medium to large upgrade options

Shortly after the upgrades to the existing corridor, a larger upgrade is projected to be required.

AEMO's modelling suggests that a medium upgrade of the existing New South Wales to Queensland transmission corridor (Option A below) is the most efficient outcome. This outcome is sensitive to a range of inputs, including demand forecasts in New South Wales.

AEMO recommends that Powerlink and TransGrid investigate all options to efficiently augment the New South Wales to Queensland interconnector, including the option of a larger upgrade, the use of HVDC and HVAC options, and the potential for augmentation staging, when seeking regulatory approvals via a RIT-T.

Option A (preferred in ISP modelling). Expanding the existing transmission corridor

The modelled project would:

- Install new Armidale–Dumaresq and Dumaresq–Bulli Creek 330 kV double circuit lines.
- Uprate Liddell–Muswellbrook, Muswellbrook–Tamworth and Liddell–Tamworth 330 kV lines.
- Augment existing substations/switching stations at Armidale, Dumaresq, and Bulli Creek.

This project is expected to increase the transfer capacity towards New South Wales by a further 378 MW.

The estimated cost of this upgrade is $560 million, although it is noted that there are common upgrades required for both of these two stages of upgrades, such as the uprating of the Liddell–Muswellbrook, Muswellbrook–Tamworth and Liddell–Tamworth 330 kV lines. The consecutive upgrades can reduce costs when comparing these two projects in isolation. The timing and potential interaction of these two upgrade options will be studied in more detail in the RIT-T assessment.

This option is considered a second stage because it takes more time to be able to establish a new corridor, and is expected to be able to be implemented by 2023.

Option B. Creating a new transmission corridor

A new 500 kV[45] transmission corridor between New South Wales and Queensland could deliver substantially more transfer capability than upgrading the existing corridor. AEMO recommends Powerlink and TransGrid consider this option when assessing the long-term needs of the network and the capability to connect renewable energy:

- Establish three new 500/330 kV substations west of Dumaresq, west of Armidale, and Gunnedah/Narrabri area.
- Install Bayswater–Gunnedah/Narrabri site–Armidale west–Dumaresq west–Western Downs 500 kV new double circuit line.

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[44] Uprating refers to works required to increase the capacity of existing infrastructure, and could involve a number of items such as conductor re-tensioning, raising the height of specific transmission towers, changes to protection, or replacing sections of transmission lines that have lower rated components.

[45] In the analysis, AEMO examined alternative options for implementation include HVAC and HVDC. Based on current projections of costs for AC versus DC, including the benefits of accessing REZ along the route, the AC options are currently projected to be lower cost. AEMO recommends that Powerlink and TransGrid further examine options for implementation when assessing this development.

- Install new 330 kV single-circuit lines between Gunnedah/Narrabri and Tamworth, Armidale west and Armidale, and Dumaresq west and Dumaresq.
- Augment Dumaresq, Armidale, Tamworth, and Bulli Creek 330 kV substations, and Bayswater 500/330 kV and Western Downs 275 kV substations.

This project is expected to increase the transfer capacity towards New South Wales by a further 1,285 MW, and towards Queensland by approximately 1,640 MW further.

The estimated cost of this upgrade is $2.36 billion. This option is considered an alternative second stage upgrade because it takes more time to be able to establish this new corridor, and has an earliest expected in-service date of 2024.

By providing a diverse route, this option reduces the risk and impact of bushfires leading to separation of the New South Wales and Queensland regions.

Option C. Using back-to-back HVDC converters

Using back-to-back HVDC converters can provide a way to increase capacity between New South Wales and Queensland up to the thermal limits of the existing transmission lines. With a non-synchronous HVDC back-to-back link, the existing network stability limits such as voltage stability, transient stability, and oscillatory stability would be largely eliminated. Control schemes in conjunction with the HVDC controls can also allow for higher thermal limits to be realised.

Although existing transmission lines are used, the use of HVDC converters mean that this is a relatively high-cost option.

The QNI Upgrade Project Assessment Consultation Report March 2014 by Powerlink and TransGrid[46] determined that implementing a back-to-back HVDC to augment the current QNI transfer capacity would:

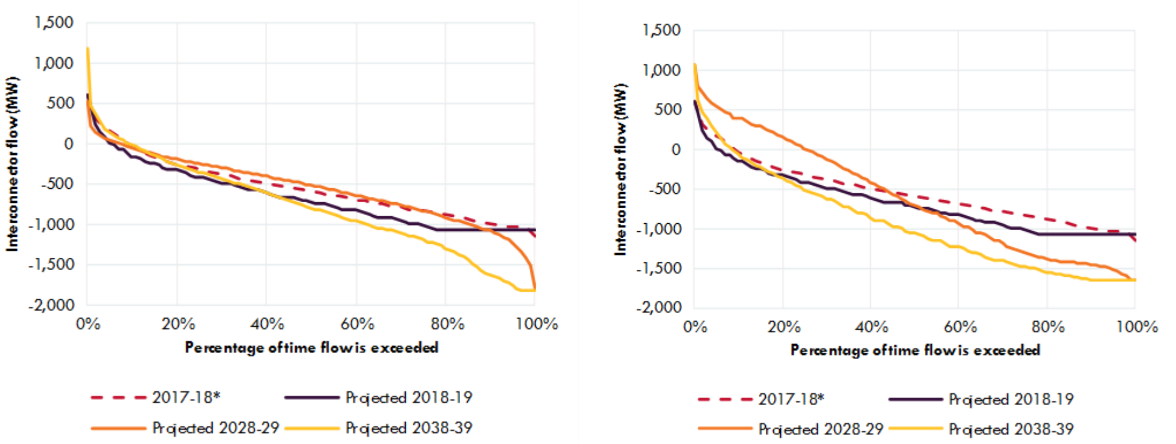
- Cost an estimated $445 million.
- Increase the transfer capacity towards New South Wales by a further 285 MW, and towards Queensland by approximately 730 MW further.

Projected interconnector utilisation

The following figures demonstrate the recent and projected utilisation of the New South Wales to Queensland interconnector:

- Following suggested upgrades to the interconnector in the early and mid-2020s, the interconnector is projected to provide periods of high transfer to New South Wales.
- Average transfers from Queensland to New South Wales are projected to increase as QRET-driven renewable generation connects in Queensland.

Figure 16 Projected utilisation of the New South Wales to Queensland interconnector, Base development plan (left) and Base development plan with storage initiatives (right)



[46] Powerlink. QNI Upgrade Study. Available at https://www.powerlink.com.au/qni-upgrade-study.

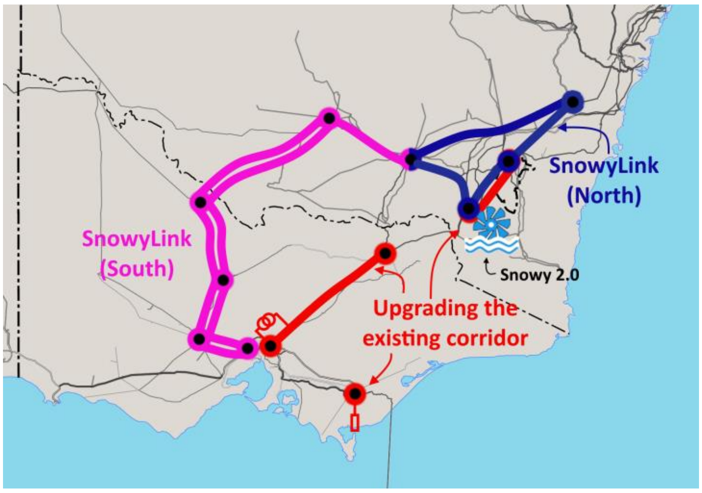
D.1.2 Staged upgrades between Victoria and New South Wales

The Victorian Renewable Energy Target (VRET) is expected to result in connection of up to 3,500 MW of renewable generation in the Victorian region by 2025. This, coupled with the projected reduction of available supply in the New South Wales region following the retirement of Liddell Power Station in 2022, is projected to drive a need for additional Victoria to New South Wales transmission capacity in the short term.

Figure 17 outlines the proposed staged upgrades to the interconnector between Victoria and New South Wales. These upgrades are discussed further in the following sections.

- A minor upgrade of the existing corridor is projected to be economic as soon as it can be developed.
- A new high-capacity transmission link (SnowyLink) would improve energy security for both Victoria and New South Wales, supporting the long-term energy transition and providing additional transmission access to the proposed Snowy 2.0 scheme.

Figure 17 Staged upgrades between Victoria and New South Wales



Stage 1 – Upgrading the existing corridor

The low capacity option to upgrade the existing link could be a standalone solution, or part of a staged upgrade. This option includes the following work:

- Install a second 500/330 kV transformer at South Morang.
- Install a braking resistor[47] at Loy Yang or Hazelwood.
- Uprate the Dederang – South Morang 330 kV lines.
- Uprate the Canberra – Upper Tumut 330 kV line.

This option would increase the Victoria to New South Wales transfer capability by approximately 170 MW towards New South Wales only. The approximate estimated cost of this option is $80 million, with an earliest in-service date of 2020. Alternative to a braking resistor, possible options include battery storage or Flexible Alternating Current Transmission System (FACTS) device to increase transient stability limit.

Stage 2 – Creating a new corridor – SnowyLink

The proposed path (SnowyLink) would create a new corridor for high power transfers between Victoria and New South Wales from Sydenham–Ballarat–Bendigo–Kerang–Darlington Point–Wagga–Bannaby. This option would be most beneficial if large amounts of renewable generation connect in Western Victoria. The SnowyLink option includes the following work:

- Install a Sydenham–Ballarat–Bendigo–Kerang–Darlington Point–Wagga double circuit 500 kV line.
- Install a Wagga–Bannaby–Snowy2.0–Wagga single circuit 500 kV loop.
- Cut-in Lower Tumut – Upper Tumut 330 kV line at connection location of Snowy 2.0, when built.

[47] A braking resistor allows for increase stability limits between Victoria and New South Wales. When switched into service, it effectively slows down accelerating generating units to prevent unstable operation following a network fault.

- Construct 500 kV substations at Ballarat, Bendigo, Kerang, Darlington Point, Wagga, and Snowy 2.0 (or expand existing substations to accommodate 500 kV plant).
- Install six 500/220 kV transformers – two at Ballarat, two at Bendigo, and two at Kerang.
- Install seven 500/330 kV transformers – two at Darlington Point, two at Wagga, and three at Snowy 2.0.
- Install a phase-shifting transformer on the Bannaby – Sydney West 330 kV line.
- Install an additional 330/220 kV 240 MVA transformer at Dederang.
- Install additional reactive plant.

This option would 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 estimated cost of this option is $2.7 billion.

This large upgrade could provide for a range of economic benefits and risk mitigations to be realised:

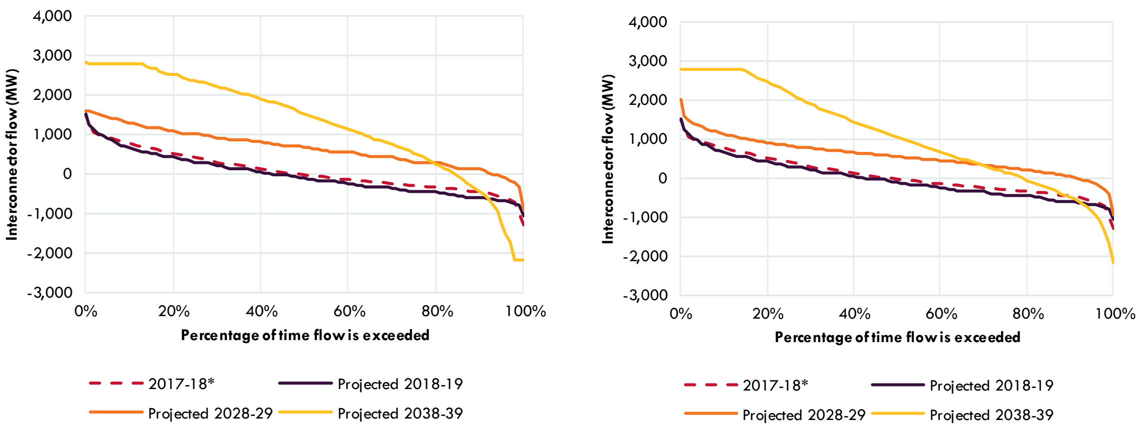
- It is projected to allow for the export of large amounts of renewable generation, installed to meet the VRET, to the New South Wales region.
- It would improve security of supply to both the Victorian and New South Wales regions by allowing for more efficient sharing of diverse generation sources.
- It can be combined with proposed upgrades from South Australia to New South Wales or Victoria (see Section 4.3.4).
- It would allow for strategic projects such as Snowy 2.0, and would improve benefits related to the Battery of the Nation pumped storage initiative.
- By providing a diverse route, it would reduce the risk and impact of bushfires leading to separation of the New South Wales and Victorian regions.
- The higher capacity would provide headroom to be able to minimise impacts of unexpected changes to generation or transmission capacity in the New South Wales, Victorian, and South Australian regions, for example if there was an unexpected failure or closure of a large power station in either region.

Projected interconnector utilisation

Figure 18 demonstrates the recent and projected utilisation of the Victoria to New South Wales interconnector:

- Following suggested upgrades to the interconnector in the early and mid-2020s, the interconnector is projected to provide periods of high transfer to New South Wales.
- After a major upgrade to the interconnector, net transfers from Victoria to New South Wales are projected to increase substantially.
- The peak capacity of the interconnector is projected to be used to improve energy sharing across the NEM.

Figure 18 Projected utilisation of the Victoria to New South Wales interconnector, Base development plan (left) and Base development plan with storage initiatives (right)



* Historic utilisation for 2017-18 does not include June 2018.

The impact of Snowy 2.0

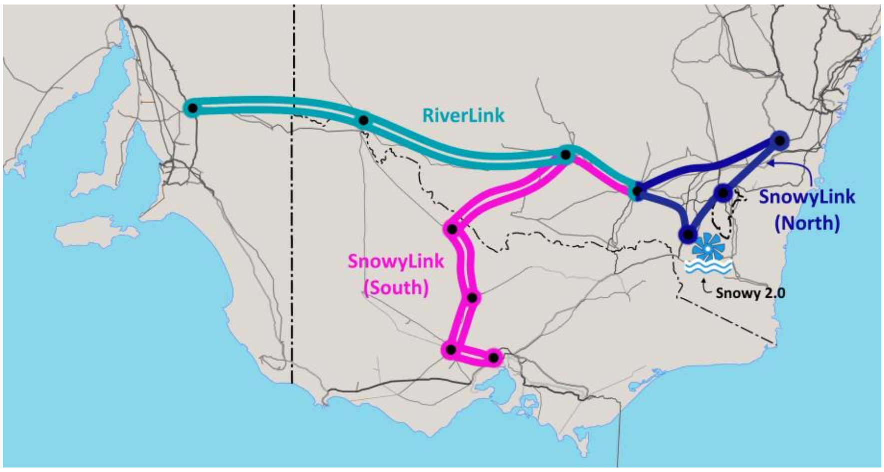
The SnowyLink development provides transmission capacity between Victoria and New South Wales, and to Snowy 2.0. In scenarios with Snowy 2.0 included, modelling shows projected benefits come from providing access to pumped hydro energy storage to both the Victorian and New South Wales regions.

The analysis with Snowy 2.0 in service in 2025 (that is, the Base with storage initiatives scenario) requires associated transmission development in New South Wales between Tumut and Sydney. The analysis also showed that net market benefits would support increased interconnection capacity in the southern sections to Victoria from 2035 (or earlier if Yallourn Power Station retires). As part of the proposed parallel HVAC network augmentations, power system studies show the need to utilise power flow controllers on the Murray–Dederang and Dederang–Wodonga 330 kV lines for increased transfer from Snowy 2.0 to Victoria.

D.1.3 Increased interconnection to South Australia

The proposed Robertstown – Darlington Point path (RiverLink) would create a new corridor for power transfers between South Australia and New South Wales. This option would allow for new capacity between the South Australian and New South Wales regions of up to 750 MW in both directions. The approximate cost of this option is $1.5 billion[48], with an earliest in-service date of 2022. The RiverLink option is currently under assessment by ElectraNet as part of the South Australian Energy Transformation RIT-T[49].

Figure 19 RiverLink and SnowyLink interconnector upgrades



The RiverLink option includes the following work:

- A new Robertstown–Buronga–Darlington Point–Wagga 330 kV double circuit line.
- An additional single circuit Darlington Point–Wagga Wagga 330 kV line.
- Two new 275/330 kV transformers at Robertstown.
- Four new 330 kV phase shift transformers at Buronga.
- A new 330/220 kV transformer at Buronga.
- 50% series compensation between Robertstown and Buronga.
- Reactive compensation.

The analysis shows that RiverLink could realise these projected benefits:

- Greater supply sharing between New South Wales, Victoria, and South Australia.
- With two diverse interconnector paths, improved security of supply to the South Australian region, and a greatly reduced risk of separation and islanding. It is important that this interconnector be designed so that a loss of the existing Heywood interconnector does not result in disconnection of RiverLink, and vice-versa.

48 AEMO's market modelling considered a cost of $1.27 billion for the Riverlink project. Recent information from ElectraNet indicates that the projected cost has increased to $1.5 billion following detailed investigations.

49 See https://www.electranet.com.au/projects/south-australian-energy-transformation/.

- GPG not being required to remain online within the South Australian region for system security. AEMO projects that a new synchronous interconnector to South Australia, in combination with system strength remediation, will remove or significantly alleviate the current requirement to keep large synchronous generators online in South Australia. The power system resilience requirements for the South Australian region are discussed in more detail in Chapter 5 of the ISP.
- Upgrade of networks between Robertstown–Buronga–Darlington Point to 330 kV also allows for increased capacity for new generation to connect in the Riverland and Murray River REZs. Modelling results show a projected increase of over 1,200 MW of generation connected in these REZs with RiverLink, compared to the results of modelling with no interconnector.

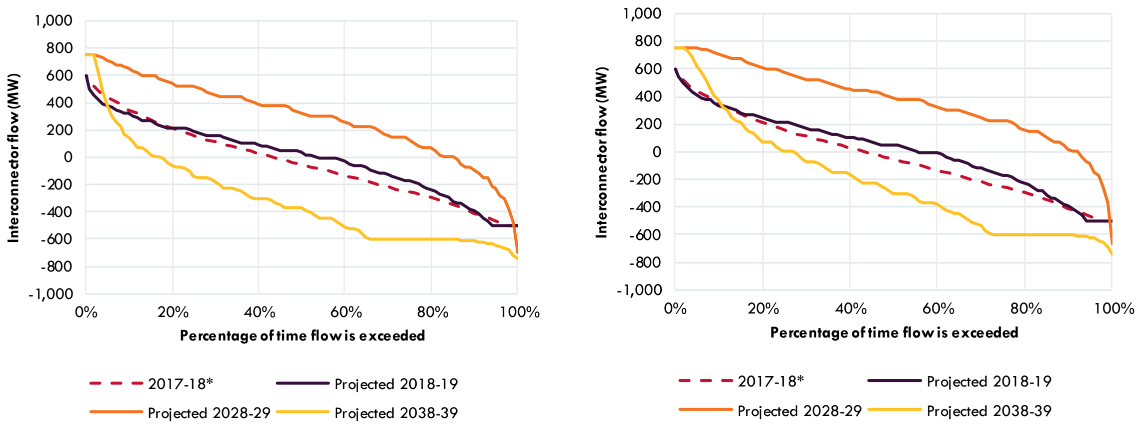
AEMO's analysis shows that the RiverLink option would be justified in both Base cases and all three scenarios (Slow change, Fast change, and High DER). The only case assessed where RiverLink did not show net market benefits by 2025 was under the IRFG sensitivity, where gas prices were assumed to fall by approximately a third and remain much lower than currently projected under most scenarios.

Projected interconnector utilisation

Figure 20 demonstrates recent and projected utilisation of the current Heywood (Victoria to South Australia) Interconnector:

- Following system strength remediation in South Australia in 2020, and the establishment of a new high capacity interconnector (RiverLink) between South Australia and New South Wales in the early 2020s, the Heywood Interconnector is projected to provide additional imports into South Australia as GPG within South Australia is displaced by coal-powered generation and renewable generation.
- In the 2030s, net flows on the Heywood Interconnector are projected to reverse as South Australia becomes a net exporter of energy, driven by development of solar PV and energy storage.

Figure 20 Projected utilisation of the Victoria to South Australia interconnector (Heywood), Neutral (left) and Neutral with storage initiatives (right)

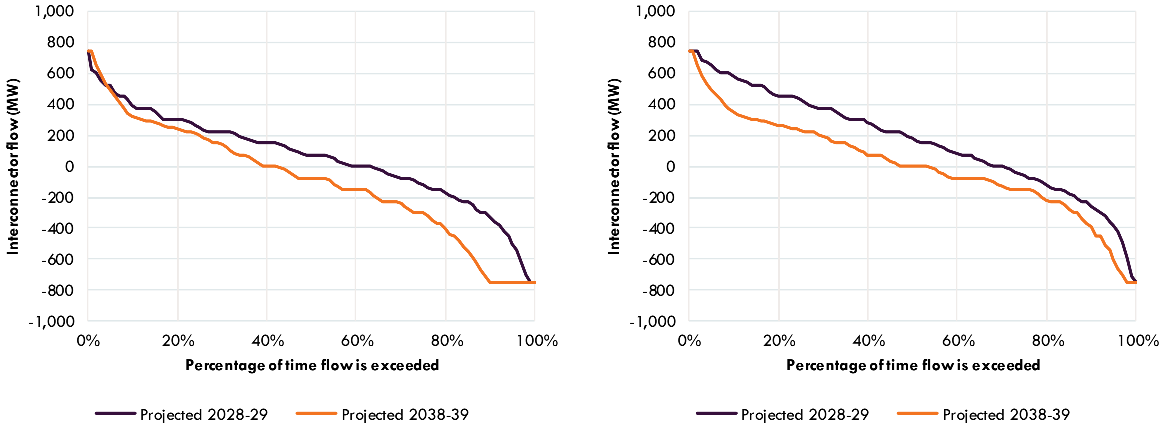


* Historic utilisation for 2017-18 does not include June 2018.

Figure 21 demonstrates the projected utilisation of the RiverLink interconnector:

- The RiverLink interconnector is projected to provide net market benefits primarily by allowing GPG in South Australia, currently required to remain online for power system security, to be displaced with coal-fired and renewable generation from the east coast – as described above.
- The RiverLink project also allows high quality renewable energy in South Australia to be exported.

Figure 21 Projected utilisation of the New South Wales to South Australia interconnector (RiverLink), Neutral (left) and Neutral with storage initiatives (right)

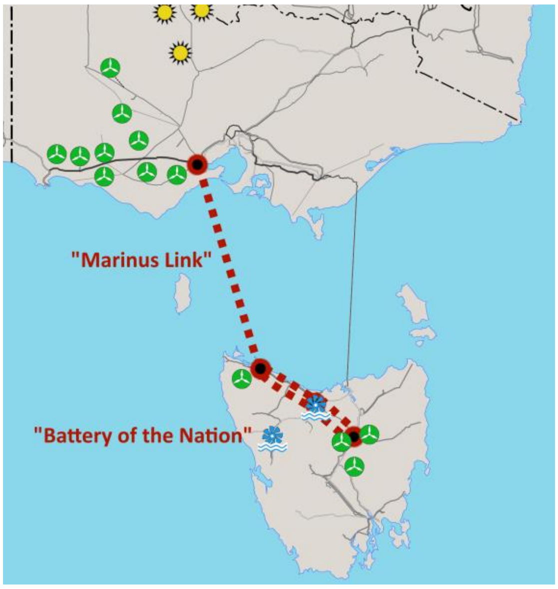


* Historic utilisation for 2017-18 does not include June 2018.

D.1.4 Additional Bass Strait interconnection

Figure 22 shows the interconnector path between Tasmania and Victoria modelled in this ISP. While several paths are being considered in the Battery of the Nation analysis, AEMO has modelled this path primarily due to the location of energy storage projects in Tasmania. For this analysis, AEMO modelled a 700 MW HVDC interconnector between Tasmania and Victoria.

Figure 22 Second Bass Strait interconnector ("MarinusLink")A



A. The dotted line shows indicatively the proposed interconnection, for the purpose of the analysis undertaken for the ISP. The exact route for a second Bass Strait undersea cable will subject to more detailed analysis and commercial considerations.

The analysis projects a significant need for energy storage, particularly from the 2030s and 2040s as coal-fired generation is projected to retire. By 2040, the analysis showed market benefits in over 16 GW of new pumped hydro storage across the NEM. However, the actual location of this amount of storage may be constrained by environmental considerations, and actual location and costs are very uncertain at this stage. AEMO notes that Hydro Tasmania has flagged the feasibility of larger amounts of storage and interconnection capacities (a third, fourth, and fifth Bass Strait Interconnector) in their Battery of the Nation project.

Additional interconnection between Victoria and Tasmania is projected to provide a range of benefits by:

- Providing energy storage to the mainland – a new interconnector is projected to provide network capacity for the development of pumped hydro energy in Tasmania (such as Hydro Tasmania's Battery of the Nation proposal), which could be exported to support the long-term need for energy storage on the mainland.

- Exporting wind energy – with additional transfer capability, Tasmania is projected to see further development of wind energy. The wind resource in Tasmania is very high quality, and provides diversity to mainland wind energy. A combination of wind and energy storage development could see Tasmania become a long-term exporter of firm renewable energy.
- Improved reliability in Tasmania – the development of wind farms, pumped hydro, and the presence of a second interconnector would improve the reliability of supply in Tasmania – including improved resilience to extended cable outages or drought conditions.

The ISP Neutral with storage initiatives scenario includes the Snowy 2.0 pumped hydro scheme, the Battery of the Nation initiative, and network upgrades – SnowyLink and MarinusLink respectively – to efficiently support both projects.

D.2 Co-ordination of the Base development plan with REZ upgrades

The ISP Base development plan has been optimised with requirements for network development to support REZs across the NEM. Table 40 summarises the projected timing of projected network developments to develop REZ capacity beyond existing network limits. The interconnector upgrades that affect REZ capacity are included in the table, and these should be considered together during feasibility studies or a RIT-T.

It should be noted that these timings are outcomes of least-cost modelling, and are indicative, based on key inputs that drive the need for these developments, including timing of coal-fired generation retirements. This modelling did not consider the practical implementation requirements or lead times, which may necessitate work and development starting many years ahead to achieve these timings.

Table 40 REZ network upgrades built out in studies

REZ name	Indicative timing by when transmission developments would need to be complete					Interconnector upgrades that increase REZ capacity
	Neutral	Neutral with storage	Slow	Fast	High DER	
North West NSW	2035	2035	>2040	2029	2037	New South Wales to Queensland
Northern NSW Tablelands	2035	2034	>2040	2026	2036	New South Wales to Queensland
Central NSW Tablelands	>2040	>2040	-	2023	>2040	
Central West NSW	2037	2039	-	2037	>2040	
Southern NSW Tablelands	2036	2036	>2040	2036	2036	SnowyLink
Murray River (NSW)	2035	2035	-	2035	2037	RiverLink
Riverland (NSW)	2033	2032	-	2024	2036	RiverLink
North QLD Clean Energy Hub	-	-	-	2030	-	
North QLD	>2040	>2040	-	>2040	>2040	
Isaac	>2040	>2040	>2040	>2040	>2040	
Fitzroy	>2040	>2040	-	>2040	>2040	
Darling Downs	>2040	>2040	>2040	>2040	>2040	New South Wales to Queensland
South East SA	-	>2040	-	>2040	-	
Riverland (SA)	-	-	-	-	-	RiverLink
Mid North SA	>2040	>2040		>2040	>2040	
Northern SA	>2040	>2040	-	2037	>2040	
Roxby Downs	2037	2040	>2040	2028	>2040	
Eastern Eyre Peninsula	>2040	>2040	-	>2040	>2040	
North West Tasmania	>2040	2035	-	2031	-	MarinusLink

REZ name	Indicative timing by when transmission developments would need to be complete					Interconnector upgrades that increase REZ capacity
	Neutral	Neutral with storage	Slow	Fast	High DER	
Tasmania Midlands	>2040	2037	-	>2040	>2040	
Murray River (VIC)	2024	2024	2024	2024	2024	SnowyLink, RiverLink
Western Victoria	2025	2024	2025	2020	2025	SnowyLink, RiverLink
Moyne	2037	2037	>2040	2032	>2040	

Immediate REZ upgrades

AEMO's ISP analysis projects that, in the near term, developing transmission capacity to support the Western Victoria and Murray River REZs is expected to be economic. Proposed network upgrades to support these two REZs are currently under consultation in the Western Victoria RIT-T[50]. In other areas of the NEM, modelling suggests that it will be more efficient to encourage generators to connect where transmission capacity is available, and then develop purpose-built REZs in preparation for retirement of coal-fired power stations.

Upgrading REZs with interconnectors

The network capacity of the Riverland and Murray River REZs will increase if the RiverLink interconnector upgrade proceeds. This network upgrade is also currently under consultation as part of the South Australian Energy Transformation Regulatory Investment Test[51]. Additional capacity between Buronga and Red Cliffs 220 kV is noted as likely to improve capacity to export generation from the Murray River (Vic) REZ to the upgraded capacity from the RiverLink upgrade.

The North West New South Wales and Northern New South Wales REZ upgrades should be co-ordinated with any upgrades to the Queensland to New South Wales interconnector.

AEMO notes that, to cater for the projected increase in capacity in QNI and generation capacity in the northern New South Wales REZs, additional 330 kV circuits from Armidale through to Bayswater, and Gunnedah through to Wollar and Tamworth, would likely be required.

Long-term REZ development

The ISP is based on a projected reduction of coal-fired generation in New South Wales (due to assumed timing of retirements of coal-fired generation at end of economic life) of 2,000 MW in 2023, 3,320 MW in 2028, and 8,840 MW in 2035-36. This capacity is projected to be replaced with a significant amount of new renewable generation in Northern, Southern, and South West New South Wales, along with storage and network augmentations. Increased imports from Queensland, South Australia and Victoria are projected to supply energy to New South Wales.

The New South Wales central region is a major load centre. The analysis projects that additional transmission network augmentation to supply this region could be justified, with the majority of supply projected to be sourced from across New South Wales through coordinated REZ development, supported by imports other regions if needed. In collaboration with TransGrid, the following additional transmission network requirements have been identified as options to maintain a reliable supply:

- Additional 330 kV lines between Mt Piper and Wallerawang.
- Additional 330 kV line between Wellington and Wollar.
- Additional 500/330 kV transformers at Wollar.
- Two 500 kV additional new circuits between the Snowy/Wagga area and Bannaby.
- Two 500 kV circuits between Bannaby and Kemps Creek.
- Power flow controllers on the Bannaby – Mt Piper 500 kV circuits to increase power transfer capability from Bannaby to Mt Piper.
- Establish a new substation between Kemps Creek and Eraring (cut into Kemps Creek–Eraring 500 kV circuits and Sydney West – Bayswater 330 kV circuits) with two 500/330 kV transformers.

[50] AEMO. Western Victoria Renewable Integration RIT-T, available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Regulatory-investment-tests-for-transmission.

[51] ElectraNet. South Australia Energy Transformation, available at https://www.electranet.com.au/projects/south-australian-energy-transformation/.

D.3 Detailed network development requirements by region

This appendix provides supplementary information on possible transmission development of identified inter-regional development and to accommodate renewable generation in Neutral, Neutral with storage initiatives, Slow change, Fast change, and High DER scenarios. These have developed in collaboration with relevant TNSPs. The identified transmission development, timing, capacity increase and cost estimates are indicative and subject to further review.

Key for indicative timing of transmission development:

Colour	Indicative timing
(blue)	2020-2030
(peach)	2031-2040

D.3.1 New South Wales

Table 41 Projected New South Wales network augmentation requirements

Zone	Network augmentation	Driver for augmentation	Neutral	Neutral with storage	Slow	Fast	High DER	Additional Capacity (MW)	Indicative cost ($M) +/-50%
Northern New South Wales (NNS)	Uprate Liddell-Muswellbrook-Tamworth and Liddell-Tamworth 330 kV lines	Increase transfer between Queensland and New South Wales (QNI Option 3 in ISP Modelling Assumptions workbook[52])	✓	✓	✓	✓	✓	+460/-190	142
	SVCs at Dumaresq and Tamworth substations and shunt cap banks at Tamworth, Armidale and Dumaresq		✓	✓	✓	✓	✓		
	2x330 kV new circuits between Armidale and Bulli Creek	Increase transfer between Queensland and New South Wales (QNI Option 5 in ISP Modelling Assumptions workbook)	✓	✓	✓	✓	✓	+460/-568	525
	Uprate Armidale-Tamworth 330 kV lines (Line 85 & 86)	Increased renewable generation in NNS	✓	✓	✓	✓	✓	300	80
	Establish Uralla Substation (cut-in Armidale-Tamworth 330 kV lines - Line 85 & 86)	Increased renewable generation in NNS	✓	✓	x	✓	✓	1500 (330 kV option) 3400 (500 kV option)	55
	2x330 kV circuits between Armidale and Uralla in NNS	Increased renewable generation in NNS	✓	✓	x	✓	x		
	2x330 kV circuits between Uralla and Bayswater; or 2x500 kV lines between Uralla and Bayswater and, a new 500/330 kV substation at Uralla (with increased renewable generation)	Increased renewable generation in NNS	✓	✓	x	✓	✓		296 (330 kV option) 654 (500 kV option)

[52] AEMO. 2018 Integrated System Plan Modelling Assumptions. Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/ISP-database.

Zone	Network augmentation	Driver for augmentation	Neutral	Neutral with storage	Slow	Fast	High DER	Additional Capacity (MW)	Indicative cost ($M) +/-50%
Central New South Wales (NCEN) & Canberra (CAN)	2x330 kV circuits between Gunnedah and Wollar	Increased renewable generation in NWNSW	✓	✓	x	✓	✓	1500	257
	2x330 kV circuits between Gunnedah and Tamworth (network to pumped storage at New England)	Increased renewable generation in NWNSW	✓	✓	x	✓	✓ (Note 1)	1500	101
	1x 500/330 kV transformer at Wollar (second)	Increased renewable generation in Central	✓	✓	x	✓	x	700	21
	1x330 kV line between Mt Piper and Wallerawang (third)	Increased renewable generation in Central and Central West NSW and flow from Bayswater/Bannaby	✓	✓	x	✓	✓	700	8
	1x330 kV line between Wellington and Wollar	Increased renewable generation in Central and Central West NSW	✓	✓	x	✓	x	1500	450
	1x 500/330 kV transformer at Wollar (third)	Increased renewable generation in Central and Central West NSW	✓	✓	x	✓	x		
	2x330 kV circuits between Central West (new substation) and Wellington	Increased renewable generation in Central West NSW	✓	✓	x	✓	x		
	Uprate the Upper Tumut-Canberra 330 kV line	Increased export from VIC to NSW (VNI Option 1 in ISP Modelling Assumptions workbook)	✓	✓	✓	✓	✓	120	5
	1x500 kV single circuit between Wagga and Bannaby, and 1x500/330 kV transformer at Wagga	Increased renewable generation in SNSW, Murray and Riverland REZs/Snowy 2.0/ SnowyLink	✓	✓	✓	✓	✓	3000	1,150
	Establish a new substation in Snowy (cut-in Upper Tumut - Lower Tumut 330 kV line - #64 and establish a substation for Snowy 2.0 connection) with 500/330 kV transformers		✓	✓	✓	✓	✓		
	1x500 kV line between Snowy 2.0 and Bannaby		✓	✓	✓	✓	✓		
	1x500 kV line between Snowy 2.0 and Wagga		✓	✓	✓	✓	✓		
	2x500 kV circuits between Darlington Point and Wagga (coordinate with RiverLink option)		✓	✓	✓	✓	✓		
	Power flow controller on the Bannaby-Sydney West 330 kV line (Line #39) to limit power flow		✓	✓	✓	✓	✓		
	1x500/330 kV transformer at Bannaby (third)		✓	✓	✓	✓	✓		21

Zone	Network augmentation	Driver for augmentation	Neutral	Neutral with storage	Slow	Fast	High DER	Additional Capacity (MW)	Indicative cost ($M) +/-50%
Southern New South Wales (SNSW)	A double circuit 500 kV line between Wagga and Bannaby	NSW coal-fired generation retirements and increased generation in SNSW, Murray and Riverland REZs and increased import from VIC	✓	✓	x	✓	x	2000	520
	A double circuit 500 kV line between Bannaby and Kemps Creek		✓	✓	✓	✓	✓	2000	190
	Power flow controllers on the Bannaby-Mt Piper 500 kV circuits (Line 5A6 & 5A7) to increase power flow from Bannaby to Mt Piper		✓	✓	✓	✓	✓		200
	Establish new substation between Kemps Creek and Eraring with 2x500/330 kV transformers (cut into Kemps Creek-Eraring 500 kV circuits (5A1 and 5A2) and Sydney West - Bayswater 330 kV circuits (32 and 38))		✓	✓	✓	✓	✓		98
	Uprate Yass-Marulan (Line 4 & 5), Bannaby-Gullen Range (Line 61), Kangaroo Valley-Dapto (Line 18), Dapto-Avon (Line 11), Marulan-Avon (Line 16) and Marulan-Dapto (Line 8) 330 kV lines		✓	✓	✓	✓	✓		10
	2x330 kV circuits between Buronga and Robertstown	Increased transfer between South Australia and New South Wales (RiverLink option in ISP Modelling Assumptions workbook)	✓	✓	✓	✓	✓	1500	1270
	2x330 kV circuits between Buronga and Darlington Point		✓	✓	✓	✓	✓		
	Uprate existing Darlington Point - Wagga 330 kV line		✓	✓	✓	✓	✓		
	Second 330 kV circuit between Darlington Point-Wagga (This circuit can be 500 kV and operated at 330 kV until the timing of SnowyLink 500 kV south in service)		✓	✓	✓	✓	✓		
	1x330/220 kV transformer at Buronga		✓	✓	✓	✓	✓		
	4xPhase shift transformers at Buronga		✓	✓	✓	✓	✓		
	2x330 kV circuits between Buronga and Wagga (or 500 kV if no storage in this area)	Increased renewable generation in Murray and Riverland REZs	✓	✓	x	✓	✓	1400	670

Note 1. A single 330 kV circuit with High DER scenario.

D.3.2 Queensland

Table 42 Projected Queensland network augmentation requirements

Zone	Network Augmentation	Driver for augmentation	Neutral	Neutral with storage	Slow	Fast	High DER	Additional Capacity (MW)	Indicative cost ($M) +/-50%
Central Queensland (CQ)	A 275 kV new double circuit line between Calvale and Larcom Creek	Retirement of Gladstone generation	✓	✓	✓	✓	✓	1200	95
	An additional 275/132 kV transformer at Calliope River (third)		✓	✓	✓	✓	✓		15
	Rebuild the Bouldercombe-Calliope River 275 kV line as Bouldercombe-Larcom Creek-Calliope River 275 kV line with high thermal capacity Rebuild the Calliope River-Larcom Creek-Raglan-Bouldercombe 275 kV line with high thermal capacity	Asset renewal Timing could be brought forward with retirement of Gladstone generation.	✓	✓	✓	✓	✓		Asset Renewal
South West Queensland (SWQ)	2x330 kV new circuits between Armidale and Bulli Creek	QNI Option 5 in ISP Modelling Assumptions workbook	✓	✓	✓	✓	✓	+460/-568	525

D.3.3 South Australia

Table 43 Projected South Australia network augmentation requirements

Zone	Network augmentation	Driver for augmentation	Neutral	Neutral with storage	Slow	Fast	High DER	Additional Capacity (MW)	Indicative cost ($M) +/-50%
Northern South Australia (NSA)	2x330 kV circuits between Buronga-Robertstown	Increase transfer between South Australia and New South Wales (RiverLink option in ISP Modelling Assumptions workbook)	✓	✓	✓	✓	✓	1500	1270 (Note 1)
	2x330/275 kV transformers at Robertstown		✓	✓	✓	✓	✓		
	Second 275 kV circuit between new switching station (on the Davenport -Cultana 275 kV line) and Mt Gunson	Increased renewable generation	✓	✓	x	✓	x	740	62 (Note 2)
	An additional 1x275 kV circuit between Davenport and Robertstown	Increased renewable generation	✓	✓	x	✓	x	1000	250
	An additional 1x275 kV circuit between Davenport and Para	Increased renewable generation	x	x	x	✓	x	1000	365

Note 1. Cost includes total estimated cost of RiverLink option including projects in NSW region.
Note 2. ElectraNet is in the process of installing a 275 kV line between Davenport and Mount Gunson South to supply Prominent Hill. This cost represents additional cost for construction of double circuit line to accommodate a second 275 kV circuit.

D.3.4 Tasmania

Table 44 Projected Tasmania network augmentation requirements

Zone	Network augmentation	Driver for augmentation	Neutral	Neutral with storage	Slow	Fast	High DER	Additional Capacity (MW)	Indicative cost ($M) +/-50%
Tasmania (TAS)	Second VIC-TAS HVDC between Port Latta/Smithton (TAS) and East Geelong (TAS)	Second VIC-TAS IC	x	✓	x	x	x	700/ 1000 (Note 1)	888
	2x220 kV circuits between Port Latta/Smithton and Sheffield	Second VIC-TAS IC and/or Wind generation in NWTAS	x	✓	x	x	x		
	Replace Sheffield-Palmerston 220 kV circuit with a new double circuit 220 kV line	Second VIC-TAS IC and/or Wind generation in NWTAS	x	✓	x	x	x		105
	2x220 kV new circuits between Palmerston and Waddamana	High wind generation in TAS Midlands REZ and pumped hydro generation in Midlands in central high storage scenario	x	✓	x	✓	x	600	70
	Uprating, paralleling and/or re-conducting of existing 220 kV lines between Sheffield and nearby hydro generating stations Additional 220 kV extensions from Sheffield to proposed pumped hydro storage generators	Pumped hydro generation in north-west (Mersey Forth) and connection to Sheffield substation.	x	✓	x	x	x	1500	Station specific and not available

Note 1. VIC-TAS HVDC cable capacity is 700 MW; Network capacity for additional generation is ~1000 MW.

D.3.5 Victoria

Table 45 Projected Victoria network augmentation requirements

Zone	Network augmentation	Driver for augmentation	Neutral	Neutral with storage	Slow	Fast	High DER	Additional Capacity (MW)	Indicative cost ($M) +/-50%
Latrobe Valley (LV)	Braking resister at Loy Yang or Hazelwood 500 kV, battery storage or FACTS device to increase transient stability	Increased export from VIC to NSW (VNI Option 1 in ISP Modelling Assumptions workbook)	✓	✓	✓	✓	✓	+170/-	80 (Note 1)
Melbourne (MEL)	An additional new 500/330 kV transformer at South Morang		✓	✓	✓	✓	✓		
	Uprate the South Morang-Dederang 330 kV lines and series capacitor; Uprate the Upper Tumut-Canberra 330 kV line (NSW)		✓	✓	✓	✓	✓		
	Replace 220 kV circuits between Geelong and East Geelong with high conductor rating	Second VIC-TAS interconnection at East Geelong	x	✓	x	x	x	300	

Zone	Network augmentation	Driver for augmentation	Neutral	Neutral with storage	Slow	Fast	High DER	Additional Capacity (MW)	Indicative cost ($M) +/-50%
Country Victoria (CVIC)	A new 220 kV double circuit line between Geelong and Keilor (replace existing Geelong-Keilor No.1 and No.3 circuits)	Increased renewable generation in Western VIC, Moyne and Murray REZs	✓	✓	✓	✓	✓	250	75
	1x220 kV new circuit between Moorabool and Geelong		✓	✓	✓	✓	✓	800	11
	Upgrade the Sydenham-Keilor 500 kV line to its conductor rating (Increase secondary plant limits)	Increased renewable generation in Western VIC, Moyne and Murray REZs and/or import from NSW	✓	✓	✓	✓	✓	800	0.5
	An additional 500/220 kV transformer at Keilor or Coordinate works associated with asset renewal of existing three 500/220 kV transformers with high rated transformers		✓	✓	✓	✓	✓	800	25
	1x500 kV new line between Moorabool and Mortlake	Increased renewable generation in Moyne REZ	x	x	x	✓	x	2000	240
	An additional 500/220 kV transformer at Moorabool		x	x	x	✓	x	1000	25
	2x220 kV new circuits between Ararat and Ballarat; and 1x220 kV new circuit Ararat-Crowlands-Bulgana	Increased renewable generation in Western VIC REZ	✓	✓	✓	✓	✓	1200	146
	1x220 kV new circuit Bulgana-Horsham-Murra Warra		✓	✓	x	✓	✓		136
	1x220 kV circuit between Horsham and Ballarat (third)		✓	x	x	✓	✓	800	233
	1x220 kV new circuit between Red Cliffs and Buronga; and 1x330/220 additional new transformer at Buronga (second)	Increased renewable generation in Murray REZ (VIC)	✓	✓	✓	✓	✓	225	50
	2x220 kV circuits Red Cliffs-Wemen-Kerang (replace existing line)	Increased renewable generation in Murray and Riverland REZ	✓	✓	x	✓	✓	1200	323
	2x220 kV circuits Red Cliffs-Kerang		x	x	x	✓	x	1200	300

Zone	Network augmentation	Driver for augmentation	Neutral	Neutral with storage	Slow	Fast	High DER	Additional Capacity (MW)	Indicative cost ($M) +/-50%
Northern Victoria (NVIC)	2x500 kV new circuits between Ballarat and Sydenham 2x500/220 kV transformers at Ballarat	Increased renewable generation in Western VIC REZ & staged development of SnowyLink	✓	✓	✓	✓	✓	2500	1,550
	2x500 kV new circuits between Ballarat and Bendigo	Development of SnowyLink and increased renewable generation in Murray REZ	✓	✓	✓	✓	✓		
	2x500 kV new circuits between Kerang and Bendigo		✓	✓	✓	✓	✓		
	2x500 kV new circuits between Kerang and Darlington Point		✓	✓	✓	✓	✓		
	2x500/220 kV transformers at Ballarat, Bendigo and Kerang		✓	✓	✓	✓	✓		
	Power flow controller on the Bendigo-Shepparton 220 kV line to limit power flow on this line to its maximum thermal capacity (if necessary).	To divert generation from Western VIC and Murray VIC REZs to NSW via SnowyLink route.	✓	✓	✓	✓	✓		
	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).	VIC access to increased generation from Snowy generators including Snowy 2.0 via SnowyLink route.	✓	✓	✓	✓	✓		150
	Automatic load shedding control scheme to manage potential overload on the Murray-Dederang 330 kV lines and Eildon-Thomastown 220 kV line	Increased import from NSW to VIC at times of high demand periods coinciding with high ambient temperature	✓	✓	✓	✓	✓	200	Not available

Note 1. Cost estimate of a braking resister is included in the total cost estimate.

Appendix E. ISP consultation feedback

E.1 Overview of consultation process

On 17 December 2017, AEMO published a document entitled *Integrated System Plan Consultation* (Consultation Paper) to provide information about, and invite feedback for, the proposed inaugural ISP for the NEM. AEMO received 65 public submissions from industry, academia, individuals, and small business to its Consultation Paper.

Submissions to the ISP were divided into two stages:

- Stage 1 submissions focused on modelling inputs.
- Stage 2 submissions addressed more general aspects of the ISP.

The consultation phase of stakeholder input to modelling closed on 2 February 2018, and written submissions on other questions and matters related to the ISP closed on 28 February 2018.

AEMO received 31 submissions for Stage 1 and 34 submissions for Stage 2.

The proponents who made submissions in each stage are listed the tables below.

Table 46 Stage 1 submissions

No.	Proponent
1	ACA Low Emissions Technology Ltd
2	AGL
3	AusNet Services
4	Australian Energy Council
5	Australian PV Institute
6	Business SA
7	Chris Mills
8	Climate Rescue of Wagga Inc.
9	Deakin University
10	Dow Chemical
11	Energy Networks Australia
12	Energy Queensland
13	EnergyAustralia
14	Engie
15	Flow Power
16	Fluence Energy
17	Meridian Energy
18	MirusWind
19	Monash University – MEMSI Submission
20	Origin
21	Powerlink

No.	Proponent
22	Renew Estate and Wirsol Energy
23	Rick Willoughby
24	Ricketts Point Power
25	Robert Ongley
26	Sligar and Associates
27	SnowyHydro
28	South Australian Chamber of Mines and Energy
29	TasNetworks
30	TransGrid
31	University of Melbourne – MEI Response

Table 47 Stage 2 submissions

No.	Proponent
32	ACA Low Emissions Technology Ltd
33	Adani
34	AusNet Services
35	Australian Energy Regulator (AER)
36	Central New South Wales Councils
37	Clean Energy Council
38	Clean Energy Finance Corp
39	Deakin University
40	Delta Electricity
41	Denis Cooke and Associates
42	Dennis Lambert
43	ElectraNet
44	Electric Energy Society of Australia
45	Energy Consumers Australia
46	Energy Networks Australia
47	EnergyAustralia
48	Joe Thwaites
49	Maoneng
50	National Wind Farm Commissioner
51	New South Wales Government
52	Origin
53	Powerlink
54	Risen Energy
55	S&C Electric Company
56	Siemens
57	SmartWires
58	SnowyHydro
59	South Australian Council of Social Service
60	Spark Infrastructure
61	TasNetworks

No.	Proponent
62	Tilt Renewables
63	TransGrid
64	University of New South Wales
65	UPC Renewables

In this appendix, section E.2 provides a summary of submissions and E.3 sets out AEMO's response to the issues raised.

E.2 Summary of submissions

Stakeholders were invited to respond to a series of questions and comments as part of the consultation process conducted for this review:

Table 48 ISP consultation questions

Ref	Questions
1.1	• The material questions the ISP seeks to address are in Section 1.3.1 [of the ISP Consultation Paper]. Are there any other questions the ISP should address? • What is the best way to achieve the policy objectives of affordable, reliable, secure power and meeting emissions targets? • In pursuing this pathway: – What are the least-regret generation and transmission developments which are most robust to different futures? – Could large-scale renewable generation in targeted zones provide an efficient solution for future power system development, and what storage and transmission investment would be needed to support such an outcome? – What is the optimal balance between a more interconnected NEM, which can reduce the need for local reserves and take advantage of regional diversity, thereby more efficiently sharing resources and services between regions, and a more regionally independent NEM with each region self-sufficient in system security and reliability? • To what extent could aggregated load shifting and price-responsive load management, made available through investment into distributed energy resources (DER), reduce the need for large-scale generation and transmission development to replace the existing generation fleet as it reaches end of life, while maintaining power system reliability and security? • What is the optimal balance between the lowest-cost pathway and having the optionality to ramp up new development if required by circumstances, such as earlier than expected generator retirements, lower than expected DER uptake/orchestration, or higher than expected development of renewable generators?
1.2	• The scenarios the modelling will use to inform the ISP are outlined in Section 1.4 [of the ISP Consultation Paper]. Recognising the time limitations to produce the first ISP in mid-2018, are these suitable scenarios to address at a high level? Should these be expanded in more detailed analysis following the first high level ISP? • How could the proposed Snowy 2.0 project impact generation and transmission development across the NEM? • How could a greater uptake and orchestration of DER (behind-the-meter generation and storage, demand response, energy efficiency, and load shifting) impact large-scale generation and transmission development? • How could proposed additional Bass Strait interconnection, for instance, driven by the Battery of the Nation project impact generation and transmission development across the NEM if it was built sooner than currently projected?
2.1	What are the key factors which can enable generation and transmission development to be more coordinated in future?
3.1	Does this analysis capture the full range of potential REZs in eastern Australia?
3.2	What other factors should be considered in determining how to narrow down the range of potential REZs to those which should be prioritised for development?
3.3	What are the potential barriers to developing REZs, and how should these be addressed?
4.1	Have the right transmission options been identified for consideration in the ISP?
4.2	How can the coordination of regional transmission planning be improved to implement a strategic long-term outcome?
4.3	What are the biggest challenges to justifying augmentations which align to an over-arching long-term plan? How can these challenges be met?
4.4	Is the existing regulatory framework suitable for implementing the ISP?

The views set out in submissions are summarised below.

E.2.1 Modelling and scenario assessment

The ISP uses scenario modelling to assess how efficient generation and transmission development is under a range of material uncertainties facing the industry in the medium to longer-term. Sensitivities are used to assess how specific drivers could impact the neutral outlook for generation and transmission development. AEMO sought feedback from stakeholders on the scenario-based approach to modelling, including the proposed conceptual sensitivities, and if there were other key questions the ISP should seek to address during its analysis.

Stakeholders were supportive of a scenario-based approach to modelling, that considers developments which are robust under a range of scenarios and can be undertaken through staged implementation.

E.2.2 Additional questions the ISP could address

Consideration was given to whether AEMO had appropriately framed the questions the ISP sought to address relating to strategic long-term NEM infrastructure development. There was general support for the questions and overarching objectives of the ISP articulated in the Consultation Paper.

A number of new or alternative questions were also proposed to provide further context for the ISP, some of which were able to be addressed in this ISP. These included:

- What is the optimal power system design to enable the connection of renewable energy resources, including through inter-regional connections, to deliver affordable, reliable, and secure power in accordance with Australia's emissions targets? (Question from Energy Networks Australia)
- Will the ISP consider interjurisdictional cost-sharing arrangements and how they will work? (Question from BusinessSA)
- Considering current levels of renewable generation in each NEM jurisdiction, particularly intermittent generation and its associated impacts on contract prices for businesses, how should costs associated with future transmission network upgrades under the ISP be allocated? (Question from BusinessSA)
- What are the lead times associated with developing traditional generation, transmission, and distribution, demand side, and energy storage solutions? How does the lead time ongoing, from concept to construction to operation, impact development of an optimal investment set, considering the risks of changing system conditions for assets with longer lead times? (Question from Fluence Energy)
- Do traditional infrastructure planning approaches allow for the dynamic nature of the NEM? (Question from Deakin University)
- What regulatory changes are needed to promote new non-network solutions (e.g., demand response, storage, etc.) and provide a level playfield with conventional transmission investment? (Question from University of Melbourne)

E.2.3 Least-regret generation and transmission investment

There was general approval of AEMO's focus on least-regret generation and transmission investment as a starting point to the staged transmission investment development plan for the power system that the ISP will deliver. Some considered that it would facilitate identification of an economically efficient power system response to the drivers of change in the sourcing of NEM's energy.

The use of a least-regret (and benefits maximising) investment decision assessment framework in the development of the ISP to determine the timing and scale of upgrades was described by some as 'option value'. A proponent submitted that transmission and generation projects that do not meet strict cost-benefit threshold in the present day, but establish the option to support further investments in the power system as required under different future scenarios, may inherently increase the value of an investment.

One proponent supported the concept of least-regret generation and transmission development insofar as it incorporates the full strategic value of those developments.

E.2.4 Scenarios should be wider than original bookends in ISP Consultation Paper

While scenario modelling was supported, and there was general understanding of the time limitation associated with publication of the inaugural ISP in mid-2018, many proponents considered that a wider range of scenarios should be modelled. If additional modelling was not possible in the inaugural ISP, proponents supported the extension and addition of scenarios and sensitivities in later ISPs as it is updated for changes to market conditions, economic factors, and the regulatory environment.

A proponent reflected that it may be more valuable to perform more detailed analysis within each scenario to improve stakeholder confidence in the modelling results, rather than widening the range of scenarios considered.

Distributed energy resources

There was consensus among proponents that AEMO must give careful and comprehensive consideration to the role of distributed energy resources (DER) in delivering lower-cost alternatives to large-scale generation and transmission solutions. Greater sensitivity in the modelling is needed to the impact of DER, including behind-the-meter technologies and technology costs. Proponents agreed that effective application of DER and demand response could provide local supply-demand balancing, reducing peak demand and better aligning demand with variable generation availability, supporting the more effective utilisation of generation and network infrastructure. This approach could potentially relieve the augmentation needs for the transmission network, reducing upstream investment. It was agreed that investment in or management of DER may support an efficient solution to addressing the energy trilemma.

For this reason, most stakeholders noted that DER should be modelled in all scenarios, and some considered that the scenarios should include an appropriate range for uptake of DER, rather than treating DER uptake as a sensitivity. It was noted that the proposal to hold several DER-related variables, such as technology costs and uptake rates, as 'neutral' across all scenarios does not suitably reflect the uncertainty surrounding the role of these technologies in the future energy system.

Another view was that DER uptake should be modelled very conservatively, noting that studies have shown that while there are no barriers to entry for DER, the uptake of these services is modest. Some proponents also suggested that care is needed to ensure the true benefits and limitations of DER to offer system support are recognised.

In their submissions, many stakeholders specifically recommended the inclusion in the modelling of integration for distributed low-cost storage opportunities (for example, pumped hydro, thermal energy storage, or batteries) across the NEM.

It was also suggested by some proponents that high penetration of electrification of transportation should be modelled in the scenarios, given it has the potential to be significant, including in respect to alternatives to fossil fuels.

Retirement of coal-fired generation and the exit of other major loads

As major contributors to the demand profile of the NEM, the retirement of coal-fired generation and the exit of other major loads was raised by several stakeholders as a factor that should be included in the scenarios or the impacts otherwise assessed through sensitivity analysis.

E.2.5 Generation intermittency

Some stakeholders noted that additional modelling of the role required of firming plant in a system with high renewables penetration and generation intermittency is required to ensure the reliability and stability of the national grid. Such modelling must look at granular dispatch over limited periods of time, rather than aggregated results of production on an annual basis.

One view was that wind generation and solar PV generation (without storage) cannot provide a level of firm dispatchable generation and that large-scale storage, by way of pumped hydro, batteries, or other storage technologies, is needed to provide any significant firm capacity to support the shift away from synchronous generation.

E.2.6 Loss factors will have an important influence on REZs

A consideration raised by some stakeholders was the importance of incorporating marginal loss factors (MLFs) in the ISP's co-optimisation process, and forecasting how MLFs may vary into the future. Given loss factors have a relatively large impact on the success of a project, consideration of loss factors would help support the long-term decision-making of generator proponents and would be welcome in the inaugural ISP.

E.2.7 Distribution networks should be considered and modelled

The opinion of a number of proponents was that there was value in considering and modelling distribution networks, rather than focusing primarily at the transmission network level. Distribution networks could support transmission upgrades, play a role in delivering REZs, and enable DER to provide lower-cost solutions. It was noted that there may be region-specific reasons for considering distribution networks. For example, one proponent suggested that large-scale embedded generation on distribution networks is, in many cases but most particularly in Queensland, continuing at a rate and volume greater than that experienced by the corresponding TNSP. There was a view that strategic planning should consider the location of generation connecting to both the transmission and distribution network, given the scale of Australia and the dispersed nature of electricity networks.

E.2.8 Modelling of emissions reduction targets

There were divergent views among some stakeholders about how emissions reduction targets including the Queensland Renewable Energy Target (QRET) and Victorian Renewable Energy Target (VRET) should be modelled. Some proponents supported the full adoption and alignment of scenarios with state-based emissions reductions targets to 2030 and 2025 respectively. Another view was that it would be more appropriate to exclude the QRET and VRET entirely from a scenario or sensitivity, given the uncertainty of these schemes arising from potential changes in state governments or national policy. Another suggested that the QRET and VRET should be specifically excluded from the Neutral scenario only, while an opposing view was to exclude them from the slow change scenario.

E.2.9 Coordination of generation and transmission development

The general consensus among stakeholders was the necessity for coordinated strategic transmission planning to ensure an integrated approach to inter-regional development to deliver the most efficient long-term infrastructure development for customers. It was noted by some stakeholders that the role of the ISP will be to examine national development trends across transmission and generation and guide large scale, co-ordinated transmission planning, contributing towards commercial decision-making for NEM participants.

It was agreed that a coordinated jurisdictional planning process would provide the platform to incentivise the most efficient development, enabling the lowest-cost electricity generation to be connected and dispatched and enhancing energy market competition. It will play an essential role in aligning market signals with long-term system requirements, facilitating future investment and achieving an affordable, reliable, and decarbonised energy supply.

A transparent and consultative planning process in development of the ISP was strongly favoured by stakeholders to ensure robust analysis. Among the views provided, it was also noted the ISP should be complemented by joint planning between AEMO, TNSPs, distribution network service providers and, where applicable, non-network service providers.

E.2.10 Renewable Energy Zones

The Finkel Review identified a gap in public information about the quality of renewable energy resources across the NEM and their suitability for generation development. Recommendation 5.1 asked AEMO to identify and map the most suitable areas across Eastern Australia for renewable generation development.

REZs identified in the Consultation Paper

Stakeholders were generally in support of the ISP mapping the best locations to develop large-scale REZs, and agreed with the REZ candidates identified. There was consensus in the submissions that these zones will promote efficiencies by economies of scale in high resource areas and capture geographic and technological diversity, supporting their inclusion in the first ISP for timely development. A view held by a number of stakeholders was that the benefits of connecting high-quality renewable resources to the electricity market will outweigh the cost of the transmission investment to the zone, where AEMO has confidence that the REZs will be well supported by generators. As noted by some stakeholders, plans to extend existing transmission networks should act as an appropriate market signal to project developers, however, other incentives may also have a role to play in this regard.

Alternative REZs

In addition to the indicative high-scoring REZ candidates that AEMO identified in the Consultation Paper, further prospective REZs were acknowledged by stakeholders as worthy of additional attention.

The Central Victorian wind REZ was identified as a prospective site, with one proponent contending the Central Victorian wind REZ would be one of the first regions to benefit from scale-efficient transmission to foster the exploitation of the region's resources. Other sites which proponents considered exhibited the appropriate mix of favourable characteristics included the North West Surat Basin in Queensland, South-East New South Wales and Australian Capital Territory, Northern New South Wales, Southern New South Wales, and North West Tasmania.

Another view was that small REZ opportunities should be included, such as in the Wide Bay region, North West Minerals Province, and the North Maranoa region of Queensland.

Prioritisation of REZ development

AEMO sought feedback from stakeholders on the factors that should be considered in determining how to narrow down the range of REZs to those which should be prioritised for development.

Transparency

During consultation, a number of stakeholders identified that AEMO's process and criteria for identifying and assessing REZs must be transparent and repeatable. The final selection of REZs will require AEMO to exercise its judgement, having regard to the wide range of factors identified, sensitivity analysis, and stakeholder feedback, and as such it was noted that the ISP should clearly set out the analysis, reasoning, and weighting of variables underpinning AEMO's identification of viable REZs. The stakeholders contended that identifying these drivers will allow the market to better understand the costs and benefits of each option, and will be a key element in their adoption and implementation by stakeholders. Stakeholders also welcome publication of forecasts of the output and constraints on each REZ, to highlight the congestion cost of a recommendation.

One view was that the ISP should not "narrow down" the number of specific REZs, as proposed in the Consultation Paper, but should identify accurately the strengths and weaknesses of each potential zone. Another stakeholder cautioned AEMO against "picking winners" in prioritising REZs without considering the careful commercial decisions that are behind choices experienced developers have made in progressing development opportunities, including environmental parameters, site specific construction, access, local community issues, and locational resource availability.

Diversity of supply

The availability of a diversity of supply within a REZ was raised by a number of stakeholders during the consultation phase, as an important factor in determining how to narrow down a range of potential REZs to those which should be prioritised for development. Diversity can embrace diversity of generation types (including availability of storage to improve firmness of capacity from the REZ) and geographical diversity (such as a dispersed generation network that crosses various climate regions). Understanding how diversity can facilitate a reliable and efficient electricity supply system will inform development of REZs.

One view was that AEMO's initial work on the ISP should focus on understanding the characteristics of all generator types, especially the diversity characteristics of wind and solar PV across the states and territories, and how these can be complemented by technologies that deliver on-demand supply, demand response, and system security services to meet future energy needs. Other energy sources that proponents considered should be available for selection and application in an integrated system could include geo-thermal energy, pumped hydro storage, tidal or wave generation, and high efficiency low emissions (HELE) coal, together with carbon capture and storage. It was proposed by some that AEMO could consider looking into these alternative sources further.

Traditional owner and community support

A number of stakeholders supported increased consultation and engagement, and suggested that engagement with traditional owners and local communities during the planning, development, and implementation phases would be very important to the success of any REZ development.

E.2.11 Transmission options

Identified transmission options

Generally, there was consensus that the correct transmission options had been identified in the Consultation Paper to the ISP, and that these options should be assessed comprehensively.

In addition to the options explored in the Consultation Paper, one view was to propose a "V" shaped transmission trajectory creating a 500 kV backbone through the NEM in Victoria. This was proposed as an efficient utilisation of the Victorian network configuration. Other transmission options which are currently being progressed and should be considered further in the ISP included:

- Increasing interconnection from South Australia to the eastern states.
- Expanding transmission capacity to the Eyre Peninsula.
- The Queensland to New South Wales Interconnector upgrade.

In considering the technologies available, several proponents suggested that there may be benefit in employing HVDC transmission technology in general across the NEM, including for a parallel HVDC network from North Queensland to South East Queensland. Development of the Tasmanian North-West transmission corridor and upgrade of the Sheffield to Palmerston transmission line and the Victoria to New South Wales Interconnector were also discussed as major transmission options that should be identified within the ISP.

Regulatory framework

A major component of the regulatory process for incremental development of generation and transmission over time is the Regulatory Investment Test for Transmission (RIT-T). The RIT-T process identifies and analyses credible network and non-network options to address an identified investment need. Consistent with the Consultation Paper, stakeholders considered whether the appropriate avenue for assessment of ISP prioritised projects is through the RIT-T process. There was a consistent theme in many of the submissions that the RIT-T for approval of regulated network investments would need to evolve to implement the ISP and deliver the significant transformational change required in the NEM. There were a range of views as to the direction of the regulatory framework's evolution.

Many proponents considered that the current framework is a barrier to the development of REZs proposed by the ISP. Specifically, stakeholders considered that the RIT-T process in its current form is not suited to scrutinising large, strategic and coordinated investment decisions such as ISP generation and transmission development.

A few stakeholders reflected that a key issue with the current RIT-T process is the widely-discussed “chicken and egg” dilemma, whereby investment in generation is currently required to lead transmission investment, yet proposed generators cannot ensure financial viability for a new project unless transmission connection is assured. It is therefore highly likely that new proposed generators may continue to face project delays as transmission investment continues to lag behind the need. It was argued by some that this market-led approach to generation planning is unlikely to deliver the most reliable and lowest cost outcome to consumers.

Other more specific limitations of the RIT-T process raised during consultation by both generators and TNSPs included:

- **Inter-regional impacts** – the RIT-T inadequately considers the joint benefits of coordinated augmentations, such as a more interconnected NEM, because the RIT-T has a single-asset focus.
- **Time delays** – dispute processes and debate over modelling and assumptions used in the RIT-T assessment lengthens lead times for transmission investment, and increases uncertainty over whether the transmission investment required to connect REZs will pass the RIT-T process.
- **Strategic benefits** – the RIT-T offers limited consideration of strategic benefits valued by consumers.
- **Option value** – historically, applications of the RIT-T have not given enough consideration to the option value of future network developments – outcomes tend to favour incremental and small-scale investments, which can be more expensive for consumers in the long run.

Stakeholders considered that a clear strategic pathway is needed to identify, prioritise, and stage generation and transmission development to implement the ISP. As transmission projects contemplated by the ISP will be responding to the unprecedented changes in generation and the potential benefits of increased interconnection, many stakeholders were of the view that the RIT-T will not be capable of providing the certainty required in a timely manner to assess strategic transmission developments as it is currently applied, nor will it necessarily capture the economy-wide benefits that will be delivered by transmission projects identified in the ISP. They contended that ISP strategic projects should not need to be justified through the RIT-T process, and instead a more effective regulatory framework that provides for strategically planned transmission to lead the development of generation may be necessary, rather than responding to demand growth.

By contrast, some stakeholders considered that investment in transmission assets must remain governed by the RIT-T process, even for delivery of priority ISP projects. The rigorous and transparent RIT-T process and cost benefit analysis was noted by these stakeholders as a robust and appropriate mechanism to assess transmission network investments, with the ISP to progress as an extension of the RIT-T and not a substitute RIT-T process. A prevailing view was that the RIT-T remains of particular importance to provide regulatory scrutiny in the long-term interests of consumers with respect to projects for which electricity consumers pay.

Evolution of regulatory framework

Some stakeholders contended that the RIT-T still has a place in the regulatory framework in ensuring that consumers do not pay for transmission over-investment, provided the regulatory framework evolves to enable more appropriate assessment for strategic energy infrastructure. Various views were articulated about how the regulatory framework could evolve to better advance the objectives of the ISP.

Suggestions included the following:

- Amendment of the RIT-T process:
  - The RIT-T could be amended to capture broader benefits in the analysis that might not have previously been included in the process. Alternatively, a further view expressed was that a more streamlined RIT-T process could be adopted by using an identified REZ as an independent and central input into a RIT-T or 'base case'. Some stakeholders suggested that these inputs should be in the form of a "committed" generation estimate, providing an independent and external set of data assumptions to be used in RIT-T applications.
- An alternative investment test to the RIT-T for strategic transmission projects:
  - An alternative model to the RIT-T could be established for when the RIT-T does not deliver, considering a broader range of economic benefits outside the electricity market (for example the impact of lower wholesale gas and electricity prices on other sectors).
- Update the RIT-T Application Guidelines:
  - AER's RIT-T Application Guidelines could be updated to include instructions explaining how TNSPs should apply the RIT-T to projects identified by the ISP. It was further suggested that this would reduce uncertainty, the potential for duplicating analysis and consequently the scope for disputes and delay.
- Ministerial direction to deliver the ISP.
- Establishing a 'conditional RIT-T' to encourage generators to commit to development in the proposed energy zone.

E.3 AEMO response to stakeholder feedback

The following table provides a summary of the stakeholder feedback received in response to the Consultation Paper, and includes AEMO's response to the feedback.

Table 49 Stakeholder feedback and responses

Comment	Proposed by	Submission Quote	AEMO's response
Development of the ISP by AEMO is supported	All (excluding ACA Low Emissions Technology Ltd)	*"Energy Networks Australia supports the ISP, which should provide the first step towards a genuinely strategic approach to coordinated generation and network planning for the NEM."* – ENA	Most consultation submissions strongly supported the development of an ISP and the delivery of a strategic approach to generation and transmission planning for the NEM. There was one divergent view on this, submitting that AEMO's Integrated "System" Plan was an unwarranted extension of the recommended Integrated "Grid" Plan. AEMO considers the system wide approach to be consistent with the intention of the Finkel recommendation.
Scenarios			
A wider range of scenarios should be modelled	AusNet Services, Energy Networks Australia, Meridian Energy, TasNetworks	*"We are concerned that these scenarios are described as 'bookend scenarios' when it is feasible to imagine community demand for scenarios with faster (and indeed slower) rates of change."* – Meridian Energy	AEMO expanded the scenarios to investigate a higher penetration of DER, and included sensitivities to investigate a greater role for gas, and unexpected retirement of coal-fired power stations. The scenarios captured a broad mix of reasonable futures that were used to test the resilience and robustness of future network and non-network solutions.
Bookend scenarios should be based on rate of technology change	Australian PV Institute	*"The rationale behind the choice of settings in the three scenarios (Neutral, Slow change and Fast change) is unclear. If the scenarios are based on the rate of technology change…"* - Australian PV Institute	AEMO designed the scenarios around the rate of evolution of the system (i.e. how quickly or slowly the existing grid needs to evolve). The scenarios are not designed around the rate of technology change. AEMO has included a range of scenarios that consider faster and slower transformational change.
Scenarios and sensitivities should include Bass Link and Snowy 2.0	AusNet Services, Engie, SnowyHydro	*"The consultation paper identifies specific sensitivities that will be considered. We appreciate that each of these are uncertainties, however both the need for Basslink, and the priority value of the Snowy Mountains resources for pumped storage, should appear in the prioritisation of projects arising from the modelling."* – AusNet Services	The ISP included a scenario with the proposed Snowy 2.0 and Tasmanian 'Battery of the Nation' projects. AEMO notes that significant work is underway on these two major storage initiatives, and this work will provide valuable new information to the market. AEMO will continue to work with the government and owners to review these projects and their role in the NEM, and update future modelling to include the latest information regarding the costs and benefits of these proposals.
Modelling should consider impact of early coal fired generation retirement and other major loads exiting the market	AusNet Services, Energy Networks Australia, EnergyAustralia, TasNetworks, TransGrid, SnowyHydro	*"The potential for early closure of existing thermal units is an additional input that should be expanded upon."* – EnergyAustralia	AEMO has included modelling to evaluate the risks of early unplanned retirements of coal-fired power stations and other relevant changes. AEMO intends to do further work to expand upon this analysis in future ISPs. Major load retirements are embedded within the core scenarios. The scenarios also capture DER, increasing levels of battery aggregation, EV, and different amounts of industrial load retirements across fast change, slow change, and neutral scenarios.
Modelling should include a very low-cost renewables scenario	MirusWind	*"The modelling needs to include an additional very low-cost renewables scenario which would reflect more rapid changes than we currently consider reasonable."* – MirusWind.	The ISP covers a broad range of technology costs trajectories in the scenarios. These costs are varied across the neutral, slow and fast scenarios.

Comment	Proposed by	Submission Quote	AEMO's response
Extension and addition of scenarios and sensitivities should occur as the ISP is updated and market conditions change	AusNet Services, Energy Networks Australia, Energy Consumers Australia, Meridian Energy, TasNetworks	*"Conceptually, TasNetworks supports the use of a base-case and two bookend scenarios as a starting point for analysis within the ISP. TasNetworks also supports the extension and addition of scenarios and sensitivities as the ISP is updated and market conditions, economic factors and the regulatory environment changes."* – TasNetworks	AEMO's consultation and collaboration with the industry will continue with subsequent ISPs and their scenarios to account for the changes to market conditions. AEMO will continue to widely consult on scenarios ahead of future ISP's, as it has done for previous NTNDPs.
Higher strong rooftop PV scenario should be considered	Australian Energy Regulator, Clean Energy Finance Corp, Australian PV Institute	*"We recommend a higher Strong rooftop PV scenario, if not in the main bookend scenarios then in the sensitivity analysis"* – Australian PV Institute	A wide range of DER uptake assumptions were considered in this ISP across the range of scenarios and sensitivities, to assess how this would affect the identified investment needs and development pathways. AEMO also included a scenario focussed specifically on very high DER penetration to determine how this would affect the identified investment needs and development pathways. In this High DER scenario, rooftop PV uptake was considered Strong.
Modelling should consider the role of distributed energy resources (DER) in delivering lower cost alternatives to large-scale generation and transmission solutions	AusNet Services, Australian Energy Regulator, Clean Energy Finance Corp, ElectraNet, Electric Energy Society of Australia, Energy Networks Australia, Energy Queensland, Fluence Energy, Flow Power, NSW Government, Powerlink, Ricketts Point Power, Risen Energy, S&C Electric Company, TasNetworks, TransGrid, University of Melbourne	*"Investment in or management of distributed energy resources within the distribution network or at a customer premise level may be the most efficient solution to addressing the energy trilemma"* – Energy Queensland	
Scenarios should include an appropriate range for the uptake of DER, rather than treating DER uptake as a sensitivity	AusNet Services, Australian Energy Regulator, ElectraNet, EnergyAustralia, Energy Queensland, Energy Networks Australia, Ricketts Point Power, S&C Electric Company, TasNetworks, TransGrid	*"TransGrid supports AEMO testing a range of DER and demand-response scenarios in the development of the Integrated System Plan, and in cases where these technologies offer a cost-effective alternative, they should be included in the Plan."* – TransGrid	
Uptake of DER should be modelled very conservatively	SnowyHydro	*"The uptake of aggregated load shifting and price-responsive load management should be modelled very conservatively. Many studies conducted by the AEMC, and the Australian Energy Council (AEC) have shown that there are no barriers to entry for these services, yet the uptake of this services is very modest (at around 250MW across the NEM). We speculate that this is due to the fact that businesses and consumers value the economic utility that comes from the consumption of electricity more highly than the economic value they receive from providing these demand side participation services."* – SnowyHydro	
'Slow change' scenario should be changed to include strong uptake of solar PV, distributed batteries and energy efficiency	Ricketts Point Power, TransGrid	*"TransGrid recommends that the 'slow change' scenario be changed to include strong uptake of solar PV, distributed batteries and energy efficiency (resulting in less need for large-scale generation and transmission development)"* - TransGrid	AEMO's scenarios reflected a range of "internally consistent" demand settings. Whilst other scenarios and settings can be constructed, AEMO considers that the core ones provided a reasonable range of demand outcomes to sufficiently test the generation and transmissions requirements of the grid. Strong uptake of solar PV and energy efficiency in a weak economic environment was considered internally inconsistent with the scenario theme.

Comment	Proposed by	Submission Quote	AEMO's response
'Fast change' scenario should be changed to include weak uptake of DER and energy efficiency	TransGrid	*"…the 'fast change' scenario [should] be changed to include weak uptake of DER and energy efficiency (resulting in greater need for large-scale generation and transmission development)."* - TransGrid	The Fast change scenario includes stronger emission reduction aspirations and strong economic growth, both driving higher electricity prices. Weak energy efficiency in this environment was consider inconsistent with the theme of the scenario, as typically energy efficiency can play an effective role in reducing emissions, and the strong economic growth provides business with confidence to invest in energy efficient solutions.
'Fast change' scenario should be modified to rapid cost reduction on grid scale battery storage costs	Fluence Energy	*"Given the broader objective of book-ending scenarios, we strongly suggest that the "Fast Change" scenario as described in Table 1 (see below) be modified to "Rapid Cost Reductions" on Grid scale battery storage costs."* – Fluence Energy	Based on this feedback, AEMO changed its assumptions in the Fast change scenario to include more rapid cost reductions for grid-scale storage.
Assumptions in relation to storage should be variable	Engie	*"The three scenarios documented in the ISP have a common set of assumptions to all scenarios in the following categories:* *-Battery storage (Neutral)* *-Grid scale storage costs (Neutral cost reductions)* *-Small scale PV and distributed battery storage (Neutral cost reductions)* *… the variability of these assumptions needs to be captured by the scenarios to assess the potential impacts on the system and costs."* – Engie	AEMO believes that the ISP covers a reasonable range of customer storage within the scenarios. AEMO's intent has been to capture a broad range of effects from battery storage on the system. The scenarios capture high and low amounts of customer storage, and fast, slow and neutral have different levels. AEMO acknowledges that storage uptake, level of storage, costs and technologies are still uncertain and will continue to review this in future ISPs.
Consider electrification of transportation penetration in modelling	Electric Energy Society of Australia, Energy Queensland, Engie, Origin	*"The AEMO Integrated System Plan needs to evaluate… changing consumption patterns especially the likely disruption from the impact of the pending electric vehicles."* – Electric Energy Society of Australia.	The ISP captures a range of EV uptake scenarios.
Modelling should include a 1.5 degrees Celsius scenario which aligns with Paris agreement emissions commitment	Climate Rescue of Wagga Inc.	*"We encourage AEMO to include a scenario that models more ambition, aiming toward limiting temperature rise to 1.5 degrees Celsius as per the Paris Agreement signatories' commitment…"* -Climate Rescue of Wagga Inc.	The scenarios in the ISP were each modelled under federal and state policy directives current at time of modelling. Specifically, the model is constrained to meet the Commonwealth emissions target to 2030, and presumes the adoption of the National Energy Guarantee as a mechanism to support efficient investment. Modelling incorporated the Large-scale Renewable Energy Target (LRET), Victoria Renewable Energy Target (VRET) and Queensland Renewable Energy Target (QRET) in all scenarios. In the strong scenario, more ambitious emission reduction aspirations were explored.
Fast change scenario should include the VRET	AusNet Services	*"In the scenarios table the contribution of the VRET is consistent for slow and fast change scenarios, but this is a reduction from the neutral scenario. Inclusion consistent with the government commitment would be more realistic for the fast change scenario."* – AusNet Services	
Exclude the QRET and VRET from a scenario or sensitivity	EnergyAustralia, TasNetworks, TransGrid	*"TasNetworks considers that a scenario or sensitivity that excludes the QRET or VRET schemes altogether would be appropriate in the ISP."* – TasNetworks	
Higher policy outcome should be forecast in fast change scenario than RET	UPC Renewables	*"The Renewable Energy Target is not sufficient government policy to frame the "Fast Change" scenario – a higher policy outcome should be forecast, e.g. 50% renewable by 2030."* – UPC Renewables	
Scenarios should include a component allowing for unexpected political requirements	Sligar and Associates	*"The… scenarios should have a component allowing for unexpected political requirements together with some form of back casting to identify potential discontinuities not identified by forward directed scenarios."* Sligar and Associates	

Comment	Proposed by	Submission Quote	AEMO's response
Scenarios should be tightened to align with the full QRET and VRET	Energy Queensland, Energy Networks Australia	*"At least one of AEMO's scenarios should include the full adoption of the QRET and VRET targets to 2030 and 2025 respectively, in accordance with the commitments made by the Queensland and Victorian State Governments."* – Energy Networks Australia	
PV cost for 2017-18 should be lower	Australian PV Institute	*"The PV build cost is too high for 2017-18. According to Solar Choice it is currently about $1.30/W for up to 10kW, about $1.15/W for 10kW to 100kW.1 Based on our industry experience the installed cost of Large-scale PV is currently about $1.40/W. We recommend the use of lower starting points then the same rate of decline."* – Australian PV Institute	AEMO acknowledges that projections of future costs of many technologies (not just solar) are continuing to change with technological advances. AEMO considers the cost projections used in this ISP are reasonable for this assessment. The ISP's technology cost assumptions reflect the investigations and projections by CSIRO in 2017. AEMO will continue to re-evaluate projected technology costs in each future ISP.
Modelling			
The best way to achieve policy objectives is through technology neutrality	ACA Low Emissions Technology Ltd	*"The current Integrated System Plan consultation document does not have power generation technology neutrality as a guiding principle or assumption."* – ACA Low Emissions Technology Ltd	The mix of generation technologies in the ISP covers a broad spectrum of renewable and thermal technologies – including coal-fired generation. In its analysis, AEMO has been careful to maintain a strictly technology-neutral position, with modelling based on costs rather than prioritisation of technologies. No risk premiums were assigned to any technologies
Modelling should be done at a time interval and granularity that reflects the realities of grid balancing	ACA Low Emissions Technology Ltd, Delta Electricity, SA Council of Social Services	*"A key consideration in the modelling should be modelling at a time interval/granularity that reflects the realities of grid balancing."* – ACA Low Emissions Technology Ltd	AEMO considers the ISP's long and short-term market modelling (outlined in the ISP methodology paper) captures the spectrum of energy market challenges including intermittency and power system security. This approach includes the analysis of services required to provide frequency control (e.g. inertia, frequency control ancillary services).
Additional modelling of the role required of firming plant in a system with high renewables penetration is required	Delta Electricity	*"New investment in renewables will increasingly incur additional costs, even as the technologies themselves get cheaper. The most obvious additional cost is the need for sources of backup generation for reliability purposes that leads to a virtual doubling of installed generation capacity to meet load."* – Delta Electricity	AEMO's modelling for the ISP assesses the need for storage and thermal generation. AEMO also notes the ISP will be incorporated as a scenario in the August 2018 Electricity Statement of Opportunities (ESOO), which will provide a broader perspective on reliability.
Generation intermittency should be modelled in depth	Denis Cooke & Associates, Electric Energy Society of Australia, Origin	*"Any meaningful analysis of generator requirements must be based on minimum and maximum diversified output, firm capacities and not average outputs or nameplate ratings."* – Members of the Electric Energy Society of Australia	For this ISP, AEMO engaged with independent experts to understand the renewable resource for each REZ and then made significant improvements to the market modelling methodology to enable more detailed investigation of intermittency and diversity of generators with increased model granularity. AEMO continues to develop improvements to its modelling and analysis, to better reflect the changing dynamics and uncertainties in the NEM.
Solutions to generation intermittency include diversity of supply and storage technologies	Australian Energy Regulator, Clean Energy Finance Corp, SnowyHydro	*"Without adequate large-scale energy storage the effectiveness of these renewable energy zones would be greatly diminished… A more even distribution of renewables across the NEM would perhaps even increase the locational diversity benefits of renewable energy."* – Snowy Hydro	AEMO's modelling included storage technologies and a collection of possible storage technologies, both deep and shallow, developed from a regional perspective. Further work to understand the costs and benefits of different types and depths of storage is ongoing. The ISP modelling approach considered the value of technology and geographic diversity in optimising a portfolio of renewables.

Comment	Proposed by	Submission Quote	AEMO's response
Wind and solar PV generation (without storage) cannot provide a level of firm dispatchable generation	Denis Cooke & Associates, Electric Energy Society of Australia	*"The intermittency of solar PV means that little reliance can be placed on the output to provide any firm capacity across the NEM at the very time it could be most needed to meet peak demands. Diversity assists in providing some degree of predictability of output but only to a limited extent."* – Members of the Electric Energy Society of Australia	AEMO's analysis showed that wind and solar provided some level of firm capacity (while noting this is less than conventional generation) and that the provision of energy storage would support energy security in scenarios with a high penetration of intermittent generation.
Focus should be on identifying least-regret (option value) generation and transmission investment	AusNet Services, Energy Networks Australia, Engie, SnowyHydro, TasNetworks, TransGrid	*"We support the least-regret approach proposed by AEMO and for this to apply to both generation and transmission. This will facilitate identification of an economically efficient power system response to the drivers of change in the sourcing of the NEM's energy."* – AusNet Services	AEMO's approach was to identify least-cost investment decisions that delivered positive net market benefits that were robust to the range of futures studied.
Include integration for distributed low-cost storage opportunities (e.g. pumped hydro, thermal energy storage & batteries) in modelling	Energy Queensland, Fluence Energy, Origin	*"A critical component for consideration in developing the scenarios is the forecast uptake of rooftop solar PV and other distributed energy resource technologies (such as battery energy storage systems and electric vehicles)."* - Energy Queensland	The ISP provides an integrated plan for development of generation, transmission and storage. In the ISP, storage technologies have been considered at both a utility scale (least cost) and residential scale (assumed uptake of battery scenarios). AEMO considers the range of storage technologies in the ISP are at an appropriate and economically efficient level.
Distribution networks should be considered and modelled	Energy Networks Australia, Energy Queensland, NSW Government, Risen Energy	*"It is recommended that ISP would benefit from including distribution networks as part of its scope."* - Energy Queensland	AEMO considers the impacts and planning of distribution networks is important. From an ISP perspective, AEMO has found there is uncertainty at the granular level of modelling of distribution networks (i.e. precisely where localised pockets of growth will occur). AEMO will continue to work with network planners on how to address this uncertainty in future ISPs.
Loss factors will impact development of REZs	Energy Queensland, Powerlink, Renew Estate & Wirsol	*"Incorporating MLFs into the ISP's co-optimisation process and forecasting how MLFs may vary into the future would help to support the long-term decision making of generator proponents.* *If impractical to include in the co-optimisation process in this first ISP, then reporting on the resulting MLFs will be informative."* - Powerlink	AEMO has added analysis on the impacts on transmission losses on REZs in this ISP.
Modelling should consider the cost of 'doing nothing'	UPC Renewables	*"We consider that the paper and the modelling need to consider the cost of doing nothing particularly in the context of "least-regret" decisions."*- UPC Renewables	In identifying the benefits of various transmission futures, AEMO has compared against a relevant 'do nothing' outcome without new transmission interconnection.
Modelling should include the impact of prolonged wind and solar droughts	SnowyHydro	*"However, our concern with these zones which may only contain wind and solar generation is the impact of prolonged wind and solar droughts."* - SnowyHydro	In this ISP, the modelling of solar and wind droughts has been captured within the traces of the generation and demand profiles. AEMO also recognises the importance of building climate risk resilience into future investment plans and these impacts will be further considered as part of future ISPs.
Gas reliability as a transition fuel should be considered	Dow Chemical, TasNetworks	*"Natural gas is an ideal transition fuel and provides an efficient basis for dispatchable power that can support the balanced increase in renewable energy."* – Dow Chemical	AEMO uses an integrated gas and electricity model. The modelling is a technology neutral, least cost approach to determine the optimal developments to meet reliability. The outcomes from this modelling show the projected future investments needed in GPG relative to other generation technologies, and projected future roles, based on the inputs. AEMO additionally investigated an increased role for gas with a sensitivity where gas price projections were roughly 30% lower than the $8-10/GJ range currently being observed.

Comment	Proposed by	Submission Quote	AEMO's response
Modelling should consider how the cost impact for customers will be distributed across regions	Business SA, Renew Estate and Wirsol	*"Business SA concurs with … the need to ensure transparency about how the costs and benefits of the REZ are shared across the NEM."* – Business SA	AEMO's focus for its 2018 ISP is to determine the least cost development plan to deliver reliable and secure supply, not how these costs should be distributed across regions.
AEMO should provide more information on how its modelling works	Energy Consumers Australia, Origin	*"Origin would welcome further detail and transparency on the methodology that will be employed when ranking the REZs."* - Origin.	AEMO has published the modelling methodology used in this ISP and provided further information about REZ selection criteria in Appendix A of this ISP.
Renewable Energy Zones			
ISP should focus on diversity in energy source and geographic location	ACA Low Emissions Technology Ltd, AusNet Services, Clean Energy Finance Corp, Deakin University, Electric Energy Society of Australia, Energy Queensland, NSW Government, Powerlink, TransGrid	*"Geographic diversity can be a cost-effective method of firming for intermittent generation from wind and solar if different time zones and weather patterns can be captured."* – TransGrid	Renewable energy resources for wind and solar technologies have been assessed across each of the identified renewable energy zones, to determine scale of the resource on an hourly basis, as well as the correlation of each resource to each other, and consumption, to best determine the most appropriate generation mix. The ISP modelling approach considers the value of technology and geographic diversity in optimising a portfolio of generation, storage and transmission.
Tidal or wave generation opportunities should be considered	S&C Electric Company, TasNetworks Meridian,	*"Tidal or wave generation is not considered nor is coastal pumped hydro energy storage, accepting that both are not yet common."* – S&C Electric Company	Information on the sources of AEMO's generation cost information can be found in the Modelling Assumptions book published on AEMO's website.
Energy sources considered should include high efficiency low emissions (HELE) coal together with carbon capture and storage.	ACA Low Emissions Technology Ltd	*"In regard to scenarios being modelled, the key contextual setting for this would be to ensure the broadest range of technology solutions were available for selection and application in an integrated system. This would include low emissions dispatchable power generation technologies such HELE coal and subsequently with carbon capture and storage, and gas with carbon capture and storage."* – ACA Low Emissions Technology Ltd	The ISP's modelling approach has been technology neutral, considering a wide range of possible energy technologies based on resource costs and operational considerations, including HELE along existing coal-fired technology, with GPG, renewables, solar thermal, battery, pumped hydro storage, and DER. The ISP's technology cost assumptions reflect the investigations and projections by CSIRO in 2017.
Selection criteria for REZ prioritisation should be transparent	Australian Energy Regulator, Energy Networks Australia, EnergyAustralia, Meridian Energy, Origin, TasNetworks, TransGrid	*"TasNetworks recognises that the final selection of REZs will require AEMO to exercise its judgement and will involve trade-offs amongst factors. TasNetworks considers that the clarity and transparency of this process is critical [and] supports a project prioritisation framework for REZ projects.* *TasNetworks considers that the publication of national assumptions book that underpins such a framework, including the reasons for departure from any standard assumptions, would also be beneficial."* – TasNetworks	AEMO has published the Modelling Assumptions book on its website and provided further information about REZ selection criteria in Appendix A of this ISP.
Community and indigenous support and engagement will be critical to successful REZ development	AusNet Services, Clean Energy Council, Energy Networks Australia, TransGrid, UPC Renewables, National Wind Farm Commissioner, Maoneng, S&C Electric Company, TasNetworks, Meridian Energy	*"We note the importance of ensuring that any potential impacts to rural and regional communities are considered and that effective community consultation is promoted in developing any proposals and modelling related to the ISP."* – Office of the National Wind Farm Commissioner	AEMO will in 2019 publish a list of potential priority projects that governments could support to deliver recommendation 5.2 of the Finkel report. There will be a need for governments and developers to engage with traditional owners and local communities to refine future proposals that consider the impacts of both new transmission and generation infrastructure.

Comment	Proposed by	Submission Quote	AEMO's response
Extent of generator interest in prospective REZs will be a factor for consideration	AusNet Services, Energy Networks Australia, TransGrid	*"Information regarding the extent of generator interest in prospective REZs should also be considered in the final REZ selection."* – Energy Networks Australia	The location of near-term generation investment envisaged in the ISP was cross-checked against current development activity. Generator and market interest has a role in the future of REZ development. The AEMC (together with other ESB members) is considering regulatory reforms to ensure that generation and transmission investment are coordinated.
REZ locations have been appropriately identified	ElectraNet, Powerlink, NSW Government, SnowyHydro, TasNetworks	*"TasNetworks considers that the Tasmanian REZs identified in the ISP are appropriate at this time."* – TasNetworks *"The development of Energy Zones in NSW, where appropriate and cost effective, would support an orderly transition to a modern energy system."* – NSW Government	AEMO notes the stakeholder support for the REZ locations.
Connecting renewable generation where transmission already exists should be favoured	Powerlink, Risen Energy, SnowyHydro, AusNet Services, TransGrid	*"[Priority factors for potential REZs] - Proximity to existing transmission network"* – AusNet Services	Coordinated and strategic development of REZ and transmission are identified in this ISP. The ISP considers the benefits associated with promoting development of renewables in areas where the network is strong and aligned with future transmission pathways.
REZs should be co-located with existing or future major industry or emerging economic opportunities	Energy Queensland, Central NSW Councils	*"[The following factors should also be considered:]* *-The potential for REZs to be co-located with existing of future major industry or emerging economic opportunities (for example, energy intensive operations such as mining, minerals processing or manufacturing), so that the infrastructure can promote economic development and deliver community benefits in regional areas."* – Energy Queensland	The ISP has provided a plan for optimal development of REZ, considering a wide range of factors relevant to coordinated and staged strategic development of the REZ and the associated network. Wider economic benefits have only been summarily considered in this inaugural ISP.
A factor in REZ location will be proximity to load centres	SnowyHydro, Energy Queensland, Risen Energy, TransGrid, AusNet Services, National Wind Farm Commissioner, Clean Energy Council	*"[Each potential energy zone in the NEM should be assessed against the following criteria:]* *-Proximity to load centres to minimise transmission connection distances and losses."* – TransGrid	The nature of the transmission network and the power flow of the transmission network (transmission capacity and transmission losses) are an important aspect of AEMO's considerations of REZ developments.
Lower cost alternatives to REZs should also be considered	Australian Energy Regulator, Electric Energy Society of Australia	*"We also note that, after carefully considering these factors, and taking into account the Finkel review finding that it may be many years until network investment occurs to connect particular REZs… that, the optimal number of REZs to prioritise for development, at this stage, might be zero. That is, it may well be that after taking a NEM-wide perspective on strategic infrastructure development, a more distributed grid delivers a higher system-wide net benefit than a more centralised grid based around REZs."* – Australian Energy Regulator.	Under the Finkel recommendation 5.1, AEMO has been requested to develop an integrated grid plan to facilitate the efficient development and connection of renewable energy zones (REZs). The ISP has assessed the potential for development of large-scale renewable generation in zones together with transmission requirements, with the objective of developing least cost plans for continued reliability. A high DER scenario was also included, and a range storage and rooftop PV was considered across the scenarios used in the analysis. The modelling results suggest that there is a role for large-scale REZs, even under the high DER scenario. The REZs that are supported by the ISP modelling tend to be located along shared transmission paths and near load centres.
Integration of REZ resources will depend on total power system cost	AusNet Services, TransGrid, Risen Energy	*"Clearly total power system cost for integration of the REZ resources… is a priority."* – AusNet Services	The objective in the modelling used for the analysis in developing the ISP is least overall cost, considering the whole power system.

Comment	Proposed by	Submission Quote	AEMO's response
Transmission development			
Appropriate transmission options have been identified for consideration in the ISP	Meridian Energy, ElectraNet, S&C Electric Company	*"Within the constraints of existing knowledge and currently expected market developments the options identified appear appropriate."* – Meridian Energy	AEMO notes the feedback from stakeholders.
Additional interconnection options should be considered	AusNet Services	*"An alternative comprehensive development option, together with staging of the development which reflects a 'no regrets' approach that AEMO would like to employ and achieves the above objectives.* *The new and augmented transmission routes in this 'V' option create a 500kV backbone through the NEM, and responds to credible or committed developments"* – AusNet Services	AEMO has considered AusNet Services' network augmentation proposal, and recommends the long-term need for a similar outcome that utilises different transmission corridors.
Transmission options have not considered how to minimise grid costs	ACA Low Emissions Technology Ltd	*"The options have not considered how to minimise additional grid costs while ensuring a highly reliable grid and achieving future emissions targets."* – ACA Low Emissions Technology Ltd	The base development plan has been compared against an alternate plan where no additional interconnection is built. The ISP outcomes identify where transmission augmentation will realise positive net economic benefits. This approach is consistent with the current regulatory framework for transmission development and the NEO. AEMO welcomes views and suggestions on alternative transmission options.
HVDC transmission technology should be considered	Siemens, University of New South Wales, Powerlink	*"For Australia, we think that there are many benefits to employing HVDC transmission technology."* - Siemens	The ISP considered multiple HVDC options to increase interconnection between regions (for example: South Australia to Queensland, and Tasmania to Victoria). If a project progresses to RIT-T stage, AEMO recommends local TNSPs should consider both AC and HVDC options.
Bass Link 2 transmission option should be prioritised	TasNetworks, UPC Renewables, Robert Ongley	*"TasNetworks considers the inclusion of additional Bass Strait interconnection as an identified transmission option within the ISP is appropriate."* – TasNetworks	In this ISP, the Snowy 2.0 and Battery of the Nation projects have been included in an additional scenario. Additional interconnection between the island and the Mainland is considered as an option in all scenarios.
Working groups between NSPs will improve coordination of regional transmission planning	Energy Queensland, Origin	*"Origin believes that a next step in this process could be for AEMO to facilitate working groups between generation and transmission businesses to examine the identified REZs."* - Origin	In preparing the 2018 ISP, AEMO consulted regularly with NSPs, and established joint working groups (e.g. Executive Joint Planning Committee, Joint Planning Committee, Market Modelling Working Group, Regulatory Working Group, Forecasting Reference Group, Planning Reference Group, and multiple Expert Panels). AEMO's consultation and collaboration with the industry will continue to build towards the 2019 ISP, which will identify priority projects in each NEM region that governments can support if the market is unable to deliver appropriate investment. Following the publication of the ISP AEMO will hold a technical workshop to give stakeholders the opportunity to better understand the underlying methodology and assumptions.
Drivers of energy infrastructure development			

Comment	Proposed by	Submission Quote	AEMO's response
System strength, system security and system resilience should be planned well ahead	AusNet Services, Denis Cooke & Associates, EnergyAustralia, Energy Queensland, NSW Government, Siemens, Tilt Renewables, TransGrid, University of New South Wales, UPC Renewables	*"We note that the ISP needs to present possible options that are not simply least cost; they must also seek to meet reliability or system security requirements."* – Energy Australia *"Long term planning with appropriate consideration for the future needs and capabilities of the transmission system, plays a major role in identifying which approach is the best credible option to achieve the policy objectives of affordability, reliability, security and robustness."* – University of New South Wales	Power system strength, security and resilience are inextricably linked. This ISP has considered these system needs through the development of different component plans that each contribute towards the goal of efficiently future proofing Australia's energy systems.
Drivers of new generation build will continue to be wholesale market price signals and settings that are exposed to investment risk rather than transmission investment	AGL, Energy Networks Australia	*"The drivers of new generation build will continue to be wholesale market price signals and settings that are exposed to investment risk."* – AGL	The ISP modelling assesses the overall efficiency of the generation mix required to meet consumption needs of the market, including consideration on the transmission networks. Generation expansion is developed based on efficient economic theory such that where a new generation development can improve total system efficiency – i.e. lowers total system costs – the generation is developed. Revenue sufficiency of existing and new generation has not been considered. Instead, it is assumed that effective market and regulatory arrangements exist to encourage efficient, competitive investment/disinvestment.
Regulatory considerations			
AEMO's planning approach needs to be guided by the framework in the current NER	Australian Energy Council	*"AEMO's planning approach needs to be guided by the framework in the current National Electricity Rules."* – Australian Energy Council	The ISPs primary focus is to balance reliability, security, and cost considerations, in accordance with the NEO, in the context of government policies on emissions. The analysis and modelling undertaken in the ISP conforms with the requirements in the National Electricity Rules. The ISP holistically evaluates Australia's energy future by developing a coordinated plan for development of transmission, generation, and demand-based resources, and DER in an integrated manner. Included in this plan is the optimal coordinated staging and design of generation and associated transmission developments. As part of the ISP's development, AEMO recognises there is a need to routinely review regulatory and market frameworks to ensure that the energy transformation occurs at lowest possible cost to consumers whilst meeting community expectations with respect to security and reliability.
Investment in transmission assets must remain governed by the RIT-T	ACA Low Emissions Technology Ltd, Australian Energy Regulator, AGL, Delta Electricity, Electric Energy Society of Australia, Energy Networks Australia, Meridian Energy	*"The current RIT-T process should determine the allowable investment in transmission and help ensure that transmission investment levels are appropriate under a range of future scenarios."* – Delta Electricity *"In regards to transmission networks, ACALET contents that, in order to ensure lowest cost outcomes for electricity consumers, the existing regulatory process for new transmission (RIT-T) should be maintained."* – ACA Low Emissions Technology Ltd.	
Coordination of transmission and generation development planning is supported	AusNet Services, Australian Energy Regulator, Clean Energy Council, Clean Energy Finance Corp, ElectraNet, Energy Networks Australia, Joe Thwaites, MirusWind, NSW Government, Origin, Powerlink, Siemens, South Australian Chamber of Mines and Energy, Tilt Renewables, TransGrid, University of New South Wales, UPC Renewables	*"The ISP in of itself will play a helpful role in facilitating coordination of regional transmission planning."* – Australian Energy Regulator *"The Government supports the development of an Integrated System Plan to provide a coherent NEM-wide assessment of the optimal development of generation and transmission, which can be taken as the 'base case' for the assessment of transmission infrastructure to connect Energy Zones."* – NSW Government	

Comment	Proposed by	Submission Quote	AEMO's response
The RIT-T in its current form will not deliver the future transmission investments required	AusNet Services, Clean Energy Council, Energy Networks Australia, NSW Government, Spark Infrastructure, S&C Electric Company, TasNetworks, TransGrid, UPC Renewables	*"The existing RIT-T is not a suitable tool for assessing long-term, strategic transmission connections. A clear implementation pathway is required for priority Integrated System Plan projects to be delivered in a timely manner."* – TransGrid *"However, current RIT-T arrangements may be insufficient to deliver the specific investment in transmission extensions needed to develop Energy Zones in time to meet future shortfalls in generation supply."* – NSW Government	As part of the ISP's development, AEMO recognises there is a need to review regulatory and market frameworks to ensure that the energy transformation occurs at lowest possible cost to consumers whilst meeting community expectations with respect to security and reliability. AEMO is collaborating with ESB members and other stakeholders to enhance regulatory and market frameworks including via the AER's review of the RIT-T Application Guidelines.[53] Among other things, these reviews will consider the role of the ISP in bringing about timely strategic planning for the power system as a whole. These projects are being coordinated by the ESB within the broader context of the ESB's review of transmission planning and interconnection.
The RIT-T should not be required for ISP strategic projects	SnowyHydro, UPC Renewables	*"There are a number of issues that make the RIT-T unsuitable for assessing the economic value of highly strategic transmission investment.* *There needs to be consideration of an approvals process for highly strategic transmission investment through the regulated transmission funding process which is both timely and avoid of gaming opportunities from Stakeholders who are incentivised to delay the relevant investment."* – SnowyHydro	
Prospective REZ identified by AEMO should have "committed" status for RIT-T purposes	ElectraNet, NSW Government, Risen Energy, TasNetworks, TransGrid	*"…the ISP could assist the RIT-T process by more clearly defining the identified need.* *A natural extension of this would be for the ISP to provide sufficiently prospective or developed REZs with "committed" status for RIT-T purposes."* – ElectraNet	
AER's RIT-T Application Guidelines should be amended for RIT-T applications associated with REZs	, Energy Networks Australia, NSW Government, TransGrid	*"To achieve the overall purpose of the ISP to deliver the transformational change at lower cost through coordination of generation and transmission investment, amendments to the RIT-T or an alternative cost benefit assessment including all relevant consumer benefits may need to be considered for these projects."* –Energy Networks Australia	
RIT-T process should be streamlined	Energy Networks Australia, NSW Government, Spark Infrastructure, TasNetworks, TransGrid	*"The RIT-T process should be streamlined for applications for the Energy Zones identified in the Integrated System Plan to reduce potential delays and duplication and improve investment certainty."* NSW Government	
RIT-T process should be amended or alternative model proposed	Clean Energy Council, Energy Networks Australia, Risen Energy, Spark Infrastructure, TransGrid	*"It is not suggested for the RIT-T to be abolished. However, an alternative model should be established for when the RIT-T does not deliver, as is the current experience."* – Clean Energy Council	
RIT-T does not sufficiently take into account interregional effects	Australian Energy Regulator, Energy Networks Australia, UPC Renewables	*"While individual TNSPs often conduct investment tests in each region as a cost-benefit analysis called the RIT-T, TNSPs are required to consider inter-regional effects as part of this framework. It is possible that, in practise, inter-regional costs and benefits are insufficiently considered and RIT-T proponents insufficiently coordinate their efforts with other market participants to understand broader costs and benefits."* – Australian Energy Regulator	

[53] AER. Review of the application guidelines for the regulatory investment tests for transmission and distribution. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/review-of-the-application-guidelines-for-the-regulatory-investment-tests-for-transmission-and-distribution

Comment	Proposed by	Submission Quote	AEMO's response
Existing regulatory framework is not suitable for implementing the ISP and is a barrier to REZs	AusNet Services, Central NSW Councils, Deakin University, Energy Queensland, Energy Networks Australia, NSW Government, Risen Energy, Sligar and Associates, TasNetworks, TransGrid	*"Other challenges include the inflexibility of the regulatory framework creating challenges for, among other things, renewable energy procurement."* Central NSW Councils	As part of the ISP's development, AEMO recognises there is a need to review regulatory and market frameworks to ensure that the energy transformation occurs at lowest possible cost to consumers whilst meeting community expectations with respect to security and reliability. AEMO is collaborating with Energy Security Board (ESB) members and other stakeholders to enhance regulatory and market frameworks including via the AEMC's review of the Coordination of Generation and Transmission Investment.[54] Among other things, these reviews will consider the role of the ISP in bringing about timely strategic planning for the power system as a whole. These projects are being coordinated by the ESB within the broader context of the ESB's review of transmission planning and interconnection.
The ISP needs to carry some regulatory weight	S&C Electric Company	*"The ISP needs to be more than "nice to have", it needs to carry some regulatory weight to ensure that transmission development occurs in a coordinated way."* – S&C Electric Company	
Transmission investment should lead generation investment	AusNet Services, TransGrid, Clean Energy Council, Sligar and Associates, Energy Networks Australia, Origin	*"To exploit the most valuable resource intensive areas, a more effective regulatory framework that provides for transmission to lead the development of generation is necessary."* – AusNet Services	
Existing regulatory framework is suitable for implementing the ISP	Australian Energy Regulator, Meridian Energy	*"As such we are of the view that the ISP and the RIT-T process will work effectively in combination to provide an appropriate level of planning and regulatory scrutiny in the long-term interest of consumers."* – Australian Energy Regulator	
ISP should identify any limitations to its implementation	Origin	*"The ISP could include a discussion on… any limitations of how the plan could be effectively used to inform efficient investment given the factors described… [high level of policy uncertainty, the inherent coordination issues when building large connection assets and increasing levels of decentralisation in the NEM]."*- Origin.	

[54] AEMC. Coordination of generation and transmission investment. Available at: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi.

Appendix F. ISP methodology

To understand how the power system can be expected to develop and recommend a strategy for the future development of the grid, AEMO has conducted extensive market modelling and cost-benefit analysis.

Modelling the increasingly complex energy ecosystem requires new, innovative techniques. For this ISP, the traditional NTNDP market modelling approach has been significantly improved, to:

1. Reflect the gas and electricity system co-dependencies.
2. Understand future investment risks as the market continues to evolve.
3. Capture the value of geographic and technical generation diversity.
4. Adequately represent the operating characteristics of storage.
5. Incorporate REZ development opportunities.
6. Enable decision-making in the presence of uncertainty.
7. Understand the system security and reliability implications of any potential grid development plan.
8. Highlight the value of building a resilient plan.

This has required AEMO to adopt a multi-staged modelling approach, as discussed in Section 2.6 of the ISP, with each stage helping to build a more complete analysis of the strengths and weaknesses of various future grid development options. As such, the ISP has evolved over the course of the analysis, as deeper insights were developed and common investment options were consistently shown to be attractive.

This Appendix provides further details of the market and network modelling employed as part of this multi-staged approach. AEMO's broader market modelling methodologies are described in detail in the *Market Modelling Methodology*[55] report.

F.1 Input sources

The input costs and related parameters used were consulted with stakeholders and the actual numbers used have been separately published in the ISP Assumptions Workbook[56].

Input data originates from many sources, both externally and from AEMO's own analysis of Australia's gas and electricity markets. A summary of these sources which, in totality, comprise AEMO's ISP Database[57] (formerly the NTNDP Database) is provided in Table 50 below.

Table 50 Summary of information sources

Information	Source
Committed and proposed transmission augmentations	Annual Planning Reports Project Summary workbook. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database.
Demand side participation	AEMO internal study, based on industry engagement, available in the ISP Assumptions Workbook. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/ISP-Database. AEMO Demand Side Participation estimates. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Electricity-Forecasting-Insights/2018-Electricity-Forecasting-Insights/Demand-Side-Participation.

[55] AEMO. Market Modelling Methodology report, available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/ISP-Database

[56] AEMO. ISP Assumptions Workbook, available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/ISP-Database

[57] Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/ISP-Database

Information	Source
Emissions intensity factors	Based on external consultation study performed by ACIL Allen – Emission Factors Assumptions Update[58], published in ISP Assumptions Workbook. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/ISP-Database.
Existing and new gas production, storage and transmission infrastructure	GSOO Inputs. Available at https://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.
Gas and coal prices	Prices are derived by AEMO based on wholesale gas and coal price forecasts produced by Core Energy and Wood Mackenzie. These wholesale prices reflect the underlying market conditions assumed in each of the forecast scenarios. AEMO has adjusted these external forecasts in the near term to reflect recent observations of wholesale prices. The price forecasts are available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/ISP-Database.
Gas production and transmission costs	GSOO Inputs. Available at https://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.
Gas reserves	GSOO Inputs. Available at https://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.
Generation inventory	Generation Information Page. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.
Generator performance parameters	Based on external consultation study performed by ACIL Allen – Fuel and Technology Cost Review[59], published in ISP Assumptions Workbook. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/ISP-Database.
Marginal loss factors and proportioning factors	Loss Factors and Regional Boundaries. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Loss-factor-and-regional-boundaries.
Minimum capacity reserve levels	AEMO internal study, published in ISP Assumptions Workbook. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/ISP-Database.
New generation technology costs	Primarily from CSIRO – Electricity Generation Technology Cost Projections: 2017-2050. Other assumptions as published in ISP Assumptions Workbook. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/ISP-Database.
Projections of demand for LNG export	GSOO Inputs based on engagement directly with LNG producers and external consultation with Lewis Grey Advisory[60]. Available at https://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.
Regional electricity energy and maximum demand forecasts and gas demand forecasts	National *Electricity Forecasting Report, March 2017 Update.* Available at http://forecasting.aemo.com.au/. National Gas Forecasts, published in GSOO. Available at https://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities and http://forecasting.aemo.com.au/.
Reliability Standard	Reliability Standards (AEMC). Available at https://www.aemc.gov.au/our-work/developing-electricity-guidelines-and-standards.
Renewable energy targets	Clean Energy Regulator Available at http://www.cleanenergyregulator.gov.au/RET/. Implementation of GreenPower, ACT 100% renewables, QRET and VRET targets as described in ISP Assumptions Workbook. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/ISP-Database.
Significant constraint equations	AEMO internal development. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/ISP-Database.

[58] Available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NTNDP/2016/Data_Sources/ACIL-ALLEN---AEMO-Emissions-Factors-20160511.pdf.

[59] Available at https://www.aemo.com.au/-/media/Files/XLS/Fuel_and_Technology_Cost_Review_Data_ACIL_Allen.xlsx.

[60] Available at https://www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/GSOO/2018/Projections-of-Gas-and-Electricity-Used-in-LNG-2017-Final-Report-19--12-17.pdf.

Information	Source
Wind contribution to peak demand	Generation information page. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information. South Australian Advisory Functions. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions. DNV-GL – Multi-Criteria Scoring for Identification of Renewable Energy Zones. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/ISP-Database.

F.2 Integrated energy modelling

The ISP Model sought to find the optimal mix of gas and electricity infrastructure investment and operation which meets the future power system needs at lowest cost for consumers across the NEM. Each scenario was examined through several stages of modelling to devise an initial plan for each respective scenario, then an overall plan was formulated which was explored across all scenarios to determine the net benefits for each individual scenario.

The integrated energy modelling approach requires extensive computation as the ISP Model considers a broad set of investment choices in generation, transmission, and storage across regions and zones, through the plan timeframe.

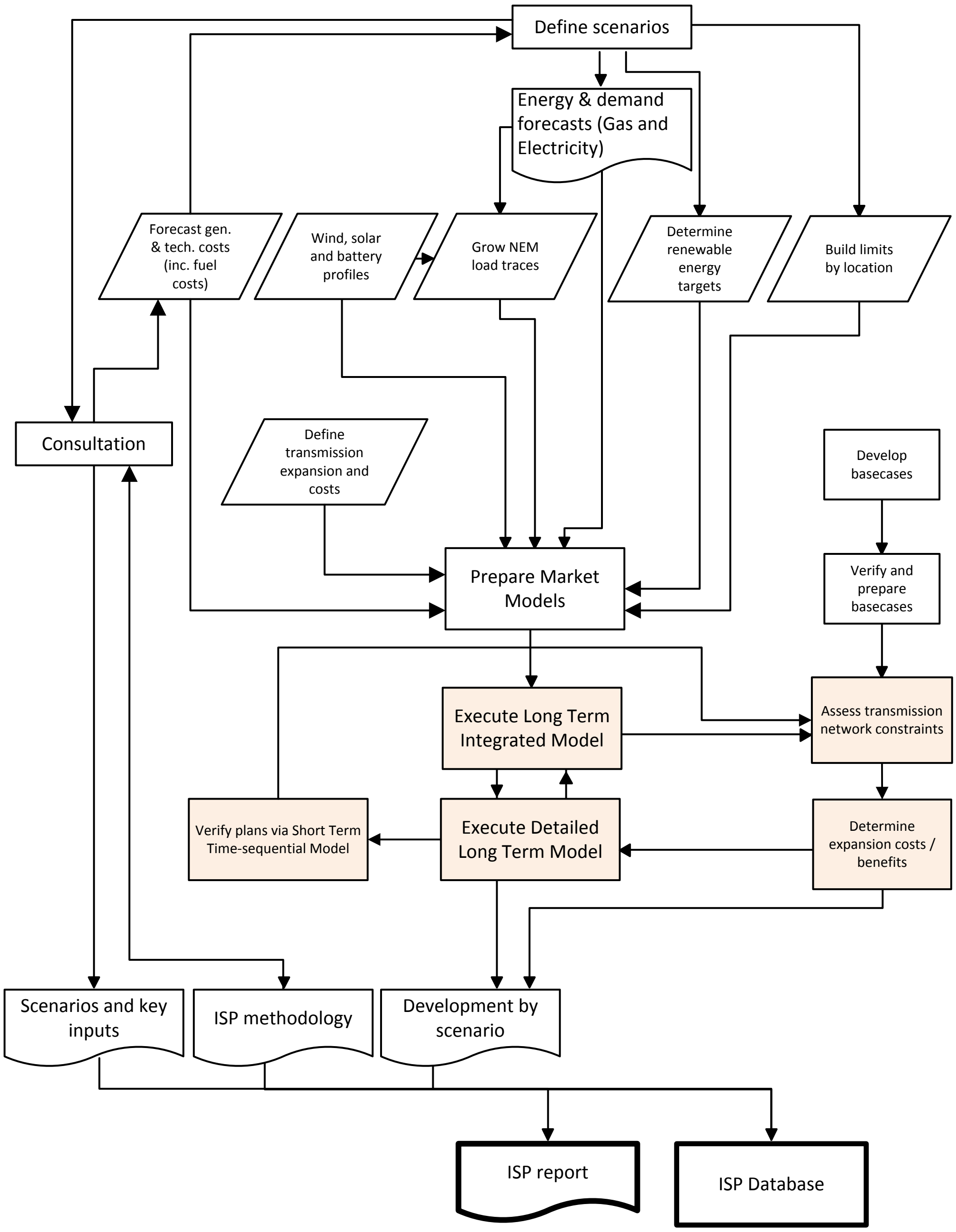
AEMO developed and maintained four planning optimisation models for the ISP. The range of models was selected to exploit certain advantages and strengths that come from varying modelling approaches. Consideration of computational effort and solution robustness was balanced at each stage to allow for the efficient development of the respective transmission and generation development outlooks.

The four key models and their respective purpose are outlined below:

- **Long-term Integrated model (IM)** – this PLEXOS® long-term co-optimised model considered the interdependencies between gas and electricity markets to determine optimal thermal generation investments, retirements and interconnection investment plans for each ISP scenario described, over the longest time horizon (to 2050).
- **Detailed Long-term (DLT) model** – this PLEXOS® long-term optimisation model looked at the electricity system in isolation and optimised new generation investments using transmission developments and other long-lived thermal generation developments of the IM. The DLT model was also key in validating timing and cost-effectiveness of transmission investments pathways identified by the IM model.
- **Short-term (ST) time-sequential model** – this PLEXOS® short-term dispatch model looked to validate the results of the DLT model by optimising hourly generation dispatch subject to power system limitations and network constraints.
- **Network development outlook model** – this PSS®E (Power System Simulation/Engineering) model examined the transmission network in detail with interconnector upgrades, new generation planting, storage and retirement of coal generators. Network augmentation options were identified and incorporated into the ST time-sequential model to validate the generation and transmission development outlook.

These models complement one another and were used in a sequential and iterative fashion to deliver a range of expansion plans for all scenarios described in the 2018 ISP.

Figure 23 2018 ISP process flow



F.2.1 Long-term Integrated model (IM model)

This PLEXOS® long-term co-optimised model considered the interdependencies between gas and electricity markets to determine optimal thermal generation investments, retirements, and interconnection investment plans for each ISP scenario.

This IM model took a broad-brushed approach, spanning a planning horizon to 2050 to understand the implications that investment decisions made now have on the power system of the future. This longer planning horizon was used to allow investment decisions to be made in the context of the environmental ambitions assumed by 2050, although the last 10 years of the analysis were not passed through to subsequent modelling phases, so any potential end effects that may influence model outcomes were removed.

It also took account of the needs of the gas industry, and the influence that gas availability may have on the operation of GPG, although it does so with relatively coarse time blocks.

For each scenario, key outputs from this IM model included:

- Identification of any early coal-fired generation retirements.

- Timing, size, and preferred route for new interconnection.
- Timing, size, and location for any new GPG expected to be relatively heavily utilised.
- Trends in future gas prices, based on gas field development.

Formulation

The IM model was formulated as a linear programming problem with the objective function minimising the net present value of total system costs over the simulated horizon, subject to constraints, such as the technical operating limitations of generation, transmission network capabilities, environmental targets, and technology costs. These constraints are outlined below.

The IM model solved the planning horizon in one optimisation step (that is, from now to 2050), ensuring capacity expansion and generation production is optimal with respect to the entire study period.

Given the scale of such a mathematical programming problem, the IM model reduced the temporal detail of the simulation. This means some of the finer intraday details that may influence choice of REZ could not be captured in this first step.

To make the problem tractable, expansion decisions were based on linear optimisation, sometimes resulting in partial interconnection upgrades, generation investments, and/or retirements. Where partial outcomes were obtained, heuristics were used to resolve these decisions into realisable project sizes in subsequent stages, rounding to the nearest assumed project size. In some instances, this involved re-running the model with and without the interconnector, to test which outcome yielded the lower total system costs.

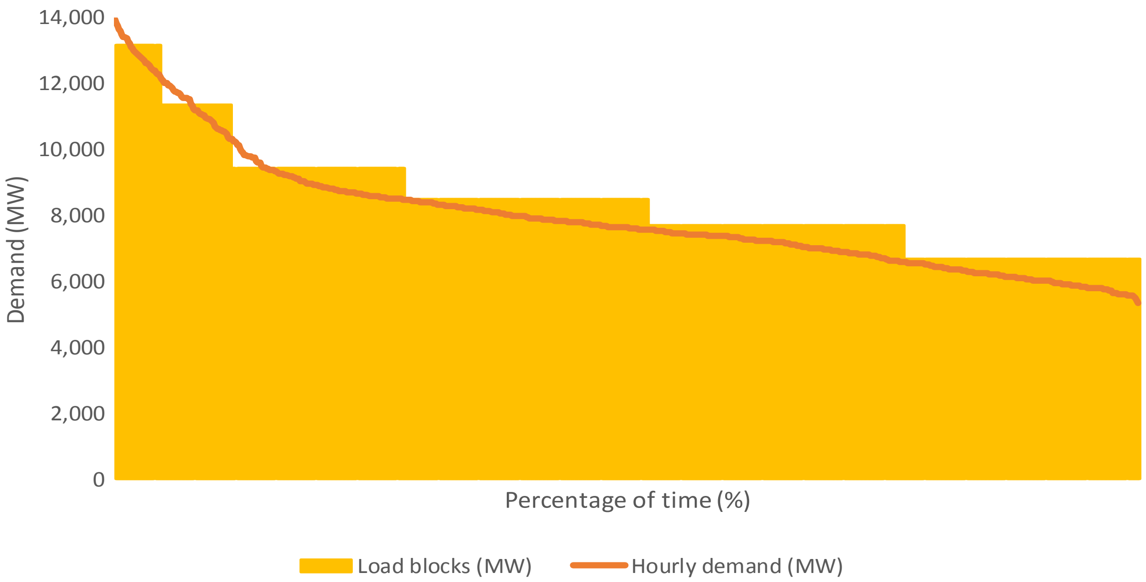
Demand approximation

To forecast the consumption patterns of the NEM, AEMO developed load traces that target its forecast annual (seasonal) maximum demand, annual minimum demand, and annual energy consumption trends over the long term. However, annual targets do not provide sufficient perspective on the needs of the consumer and the requirements of the power system to generate energy. AEMO used the 2013-14 reference year to develop hourly measures of consumption on a regional basis, maintaining the underlying consumption patterns associated with weather events that occurred in that year. Generation resource profiles for variable renewable resources were also then taken from measurements during the 2013-14 reference year, to ensure consistency of supply and demand and preservation of any correlations due to weather. The developed hourly representation of consumption was a consistent input to all models, although less granular approximations of this data were used in some stages to manage model performance.

For the IM model, the hourly demand traces were approximated using a Load Duration Curve (LDC) approach. Monthly LDCs containing six simulation periods each (blocks) were chosen to represent the horizon. The number of periods simulated was therefore reduced to: number of months × blocks × number of years.

Under the LDC approach, the input hourly load trace for each year simulated was first cut into months, then each month was fitted with an LDC, which was sliced into six blocks (see Figure 24). The slicing method used the least-square approach, which produced a more accurate fit by applying a bias towards peak and off-peak periods.

Figure 24 Six load block approximation of a monthly hourly demand



Both the IM model and the DLT also used an operational demand trace as the starting point, which is already 'net' of rooftop PV generation, such that the expansion model targets the consumption needs from energy generated and transmitted from the grid.

Retirement candidates

The IM model allowed for existing generators to retire before the end of their technical life if the early retirement minimises total system costs. The main factors that may drive economic retirements in the IM model are demand reductions, emission constraints, and fast development of renewable energy, which typically have lower operating costs. The model also considered options to refurbish coal-fired generation as an alternative to retirement.

Generation build limits

The IM model considered a wide range of build options for generation and storage technologies, listed in the Assumptions Workbook. Build limits associated with generation investments were incorporated to reflect maximum development levels for generation technologies on at least a regional basis, considering resource and transmission access, and lead times for development.

REZ build limits

In total, 34 potential REZs have been devised across the NEM and the characteristics of the resources in those zones determined. The planning process then sought to determine which mix of plant from which REZs is the optimum, taking into account the diversity of those resources, their costs, and any storage required for balancing supply and demand.

High level network studies were undertaken to identify limits on the amount of additional generation which can be accommodated within the existing network. The limits represent existing transmission access, and these limits can change either due to:

- Interconnector developments which can improve transmission access to REZs, or
- Explicit transmission developments that increase, at an appropriate cost, transmission access between the NEM transmission network and the REZ.

Through power system analysis, REZ build limits and opportunities to relax these limits were assessed by:

- Determining the amount of additional generation which can be added within the existing transmission network capability.
- Determining the amount of additional generation which can be added with inter-regional network upgrade options.
- Identifying network expansion to connect REZs to the major transmission network and amount of generation which can be accommodated.
- Estimating the cost of transmission network expansion to connect REZs, and converting the cost estimate to an annualised cost per MW equivalent.

The cost per MW for each REZ was then applied within both the IM and DLT models, as a simple linear penalty cost imposed on development of REZs beyond existing transmission connection capabilities.

In this way, each REZ may provide 'free' connection capacity up to existing assumed transmission capabilities. The IM model traded off the cost of building more intra-regional transmission to access additional capacity in excess of these limits against building new (potentially lower quality) generation in locations where spare transmission capacity exists.

Integrated gas-electricity co-optimisation

The IM model co-optimised development of electricity generation and transmission and gas production and pipelines to meet the future energy needs of consumers of both the NEM and eastern and south-eastern gas markets. It co-optimised development of energy infrastructure, considering the costs and benefits of development of either augmentation option. For example, development of GPG can be located near to existing transmission (potentially requiring gas pipeline expansion), or near to existing pipelines (potentially requiring electricity transmission expansion).

This is an important step in the ISP process, as build decisions that affect the operation of GPG need to be cognisant of the broader energy impacts, associated gas system costs, increases in gas demand, and corresponding effects on gas prices for GPG.

Transmission builds

AEMO has worked closely with TNSPs to establish a range of potentially attractive network upgrades and new interconnectors for inclusion in the infrastructure co-optimisation. Many of these transmission projects have previously been identified by jurisdictional planning bodies in their annual planning reports (APRs), long-term planning documents and submissions to the ISP consultation, and include options to build links through new transmission corridors. The upgrade options are focused on both increasing transfers between regions and accessing REZs. The cost and performance characteristics of all these options has been determined and preliminary constraint equations developed.

Interconnector options differ in terms of lead time, investment costs, route, and transfer capabilities. The model selected projects for inclusion in future network development based on their ability to reduce total system costs. Further to the least-cost criteria, the model also considered constraints capturing mutual exclusivity logic, which prevented some projects being built concurrently or sequentially, depending on the specifics of the augmentation. These assumptions were developed in consultation with the relevant TNSPs.

Other network limitations

The IM model incorporated a simple representation of the forward and reverse[61] transfer capability of interconnectors based on estimates of transfer limits between regions at times of peak demand. These are static limits that set the maximum flow allowable in the model. Operational interconnector limits change in response to a significant number of real-time variables that are impractical to consider in long-term models. In the ST time-sequential model, interconnector limits were represented through constraint equations, which set interconnector limits based on system conditions.

Emission constraints

The ISP must operate within the context of a range of government policies that apply both nationally and in the states in developing these plans. The choice of investments in generation, storage, and transmission is influenced by these polices, as is the mix between distributed and utility-scale solutions. AEMO adopts a consistent process across all its major reports to include existing government policies within its modelling. AEMO has therefore incorporated the Commonwealth Government's policy on emissions reductions in the cases analysed, as well as the Victorian and Queensland Governments' renewable energy policies. One scenario to test the impact of a faster reduction in emissions has also been included.

The least-cost solution was determined, subject to meeting these emission constraints and renewable energy targets.

Inter-temporal energy constraints

Inter-temporal energy constraints limit the generation production from some generation facilities. For example, annual rain flow dictates hydroelectric generation. The IM model avoided long-term draw-down of water storages and maintained overall water levels year to year by ensuring the water storage end level was the same as the initial level each year.

For some generators, these inter-temporal energy limits may be represented by an annual operation limit, rather than explicitly modelling the management of energy storages if this is impractical, given the impact these more detailed limits may have on model simulation performance.

This is further explained in AEMO's market modelling methodology document[62].

The Snowy 2.0 and Battery of the Nation project options were each represented as 'closed' pumped hydro systems according to the schematic depicted in Figure 25.

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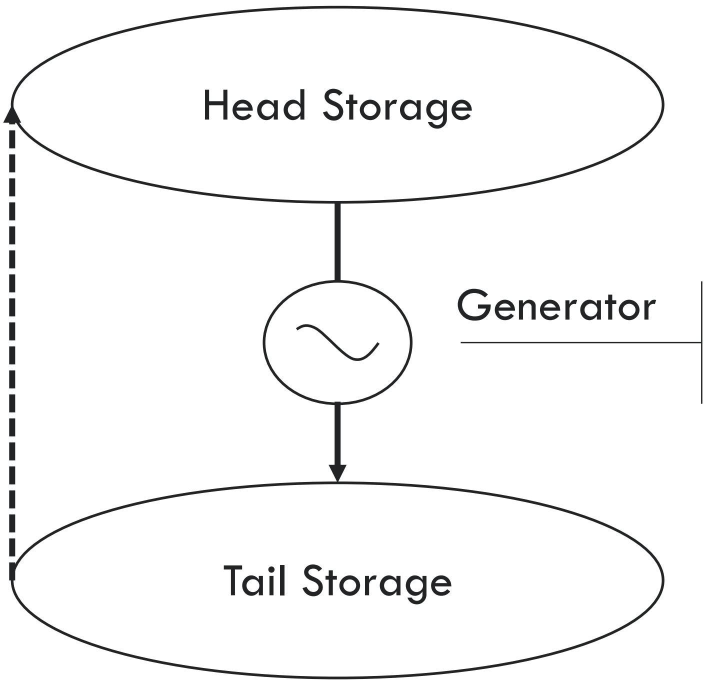
[61] Each interconnector has a conventional 'forward' direction. For example, on Basslink positive or forward direction flow is from Tasmania to Victoria.

[62] Available at http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NTNDP/2016/Dec/Market-Modelling-Methodology-And-Input-Assumptions.pdf.

Figure 25 Pumped storage modelling components



Each scheme encompasses an upper reservoir, a pumped hydro generator and a lower reservoir. Operation was managed such that water was recycled between reservoirs, considering the maximum power available to generate electricity and to pump water between reservoirs, capturing pump efficiency and reflecting initial water availability. No natural inflows were explicitly modelled in this year's ISP, so only the initial water volume is available to be used within the closed system. Head and tail reservoir of the 2,000 MW Snowy 2.0 and 1,500 MW Battery of the Nation projects were sized to deliver storage capacities of approximately 168 hours and 24 hours respectively.

Reliability constraints

Inherent in the ISP is the assumption that the enduring policy certainty contemplated by the National Energy Guarantee supports efficient, technology-neutral investment decisions that achieve targeted emissions levels while maintaining system reliability. The reliability standard, set by the National Electricity Rules, specifies that a region's maximum expected unserved energy (USE) should not exceed 0.002% of energy consumption per year.

Due to the lack of granularity in the IM model, it is not possible to get an accurate, probabilistic assessment of the USE level in any given year. Instead, minimum capacity reserve levels for each region were used as a proxy, before more detailed assessments of supply adequacy were simulated in future modelling stages with more granular models. These minimum capacity reserve levels were generally set equal to the size of the largest generating unit (although may be adjusted over time if the time-sequential modelling indicates that more firm capacity needs to be built in a region to avoid reliability standard breaches). The IM model ensures that sufficient firm capacity is installed/maintained within each region, or imported from neighbouring regions, to meet these minimum capacity reserve levels.

Key reserve modelling inputs included:

- Minimum capacity reserve levels (in the first instance, set to the size of the largest generating unit in the region).
- Maximum inter-regional reserve sharing (based on notional interconnector transfer capabilities).
- Firm capacities (discounted for wind farms and solar farms to reflect the intermittent nature of these technologies).

IM modelling limitations

Given the size of the mathematical optimisation problem associated with the LT model, problem complexity needed to be simplified to make runtime manageable:

- Monthly LDC – under the LDC approach, all system constraints were applied, except for unit commitment and other inter-temporal constraints that imply a chronological relationship between individual intervals. Since chronology is not maintained within a month, storages can only be balanced at a monthly level. Non-chronological modelling also reduced the model's ability to fully appreciate renewables' intermittency and geographical diversity between sources.

- Linear programming – this limited the ability of the IM to identify the timing of appropriate sized transmission pathways, as fractions of an interconnector may be built over several years. It was not a binary decision to build all or nothing in a year. Viability of mutual exclusivity logics and multiband REZ constraints was also affected by the lack of integers in the problem formulation.

These limitations were improved or addressed by the DLT, which was used to further develop the transmission plan and optimal generation developments considering the effect of key economic drivers of each modelled scenario.

Despite these limitations, this first step was critical to ensure the gas and electricity co-dependencies were captured and that future stranded asset risks are considered when making investment decisions in the near term.

F.2.2 Detailed long-term model (DLT)

The IM model guided the ISP process with respect to timing and size of any interconnector upgrades or new builds, and large thermal investment or economic retirements. However, partial builds or retirements were allowed, as discussed above. The DLT refined these build decisions by effectively assessing the value to the power system with and without these investments, to gain a greater understanding of the net market benefits under alternative augmentation outlooks. Interconnector options that had not been selected in any of the IM simulations were discarded at this stage in the analysis.

The DLT placed greater emphasis on the value of geographic and technological generation and fuel diversity to determine the most economically efficient locations for REZs and the optimal mix of wind, solar, storage, and peaking plants associated with alternative augmentation outlooks. To do this, the DLT utilised finer chronological resolution to capture diurnal and geographic renewable energy variability, and the operation of storage solutions to complement this variable renewable energy.

Due to computational limitations, the finer chronological resolution in this DLT came at the expense of the planning horizon. The 20-year plan period was broken into four steps of five years. Therefore, in any step, generation expansion decisions were made with only up to five years' foresight. Given assumed continued cost reductions of renewable energy technologies and storage technologies, allowing the model to invest in these technologies based on limited future foresight is not likely to result in significant regret cost (unlike build decisions for larger thermal plant, which may be exposed to volume risk as emission constraints become more constraining over time). The five-year planning step is therefore considered an acceptable trade-off for this second optimisation, to better assess the mix of generation technologies and locations that minimises total system costs, including the cost of transmission access and the need for balancing services such as storage.

Certain interconnection options and combinations of options were consistently identified across all scenarios in the DLT as part of the least-cost solution to address the power system needs. Interconnector investment decisions common to most, if not all, scenarios formed the basis for developing a number of "candidate plans". These candidate plans represented a suite of interconnector upgrades and new transmission developments that varied with respect to timing, route, and size. In some candidate plans, some interconnector options were delayed indefinitely.

The DLT model was then used to evaluate the candidate plans in more detail, testing performance under each scenario. The portfolio of energy resources, storage and REZ developments was re-optimised for each scenario and candidate plan, assuming that generation and storage investment decisions would be influenced by future grid expansion.

The outcome for each scenario and candidate plan is a 'least resource cost' solution, constrained to meet all reliability, security, and emissions constraints. To assess net market benefits in each scenario, the investment and production costs for each candidate plan were compared against a counterfactual where no new interconnection investment was assumed. The candidate plan that consistently yielded the highest net market benefits across the scenarios was selected as the Base development plan for the ISP. This plan comprised a portfolio of energy resources and transmission (including REZ developments) for each scenario.

Steps taken to transition from IM to DLT

For each scenario modelled in the IM, the steps taken to integrate the DLT with the IM were specific to the decision made in the IM. These are outlined in the following sections.

Interconnector augmentations

Given the linear limitation of the IM expansion plan, all augmentations that were installed by at least 50% of the notional interconnector size by the end of the planning horizon were tested by the DLT model. These options were manually committed in the DLT and tested against counterfactual simulations that did not include their development, to identify whether the augmentation delivered a lower overall system cost. Counterfactual simulations were performed in all cases to demonstrate the ability of each solution to deliver savings in total system costs. Sensitivities on augmentations timing were also undertaken to identify the optimal timing with respect to system costs as well as implications on the development of the generation mix as outlined by the DLT, given the increased granularity of the model. These counter-factual tests and investigations were conducted before the finalisation of the candidate plans.

Retirements

IM linearity also led to partial early retirements under some scenarios, requiring the adoption of rounding methods to determine whether and when a generator was to be considered retired (if an economic retirement was identified by the IM). As for interconnector augmentations, any retirement of at least 50% of a unit by the end of the horizon was validated (as a whole unit retirement) by the DLT model.

Thermal generation investments

Any thermal generation developments with high expected utilisation (such as new coal plant or CCGTs) were optimised by the IM and incorporated into the DLT model. For partial new entrants identified by the IM model, generators that exceeded 50% of the standard unit size of a particular technology type were included in the DLT modelling.

REZ build limits

The REZ build limits fed into the DLT under each scenario were similar to those used in the IM model, but were increased in cases where an interconnection pathway identified in the candidate plan passed through the REZ, essentially opening up access to more renewable generation. These limits, in the form of constraints, established an upper bound to the total amount of generation capacity that could be developed in each area. Soft constraints continued to be applied to capture the cost of intraregional augmentation necessary to develop REZs beyond the existing transmission capacity limits.

Formulation

The DLT Model was formulated as a linear programming problem, with the objective function minimising the net present value of total system costs over the simulated horizon, subject to the same range of constraints as discussed in the IM Model. The DLT is a stand-alone electricity optimisation model which mirrors the IM's assumptions, constraints, and logics, but differs significantly in the way the mathematical problem is optimised.

The DLT model is a chronological optimisation which has greater resolution relative to the IM model, but still groups some contiguous hourly periods together into blocks where load levels are similar. This technique allowed increased granularity to preserve the original chronology of demand time series, ensuring a greater reflection of renewable intermittency, storage balancing requirements and capabilities, and other inter-temporal constraints which require a chronological relationship between simulation intervals.

Computational feasibility was maintained by solving the problem in multiple steps of five years. The decision set was also reduced, compared to the IM Model, with interconnector augmentations/new builds and high-utilisation thermal generation builds/retirements excluded from the optimisation.

Demand approximation

For the DLT model, the hourly demand traces were approximated using eight chronological load blocks within each day of the simulation horizon, dramatically increasing the model's granularity when compared to the IM Model. These load blocks were created using a weighted least-square fit method which performed an optimisation that minimised the sum of squared errors (that is, the square of the difference between the hourly demand fed into the model and the step function approximation). The weighted least square approach has the advantage of fitting the step function more tightly to the original demand time series – allocating more blocks to higher load periods and less to periods of low demand. The duration of each block can therefore vary depending on how the underlying intervals are grouped together.

Figure 26 provides an example of eight load blocks approximating the forecast hourly underlying demand of New South Wales for a sample day in 2018-19. The methodology produced a load block 'trace' that varies to reasonably fit the hourly demand profile. More load blocks are reserved to shoulder and peak periods as a result of the weighted least-squares approach, whereas off-peak hours are generally represented by fewer and thus longer blocks.

Figure 26 Load blocks vs chronological load

Preserving chronology is important in the DLT given the diurnal nature of solar generation, and tends to result in selection of a mix of renewable resources that is more diverse than the IM Model. This is because the increased granularity increases the ability of the model to take account of resource intermittency and value geographic and technological diversity. The operation of energy storage is also able to be more realistically captured, particularly for shallow storages.

Constraints

The DLT also captured the impact of the same reliability, inter-temporal energy, emissions and network constraints applied in the IM model.

Limitations

Given the size of the mathematical optimisation problem associated with the DLT model, the following simplifications were necessary:

- **Horizon** – to manage the overall problem size, and incorporate sufficient granularity and a chronological approach, a multi-step solve was necessary to ensure problem tractability. The DLT optimised the horizon in five-year steps, thus with reduced foresight into future years when making build decisions. Given assumed continued cost reductions of renewable energy technologies and storage technologies, allowing the model to invest in these technologies based on limited future foresight is not expected to have a material impact on the least-cost solution.
- **Granularity** – the use of eight blocks per day was a close approximation to the full chronological load trace, however it still left a certain degree of approximation and thus the potential risk of smoothing some renewable intermittency. When testing more granular chronologies, eight blocks per day was found to give a reasonable trade-off between problem tractability and level of detail captured. The choice of load blocks affects load, wind, and solar representations.
- **Intra-regional developments** – the penalties of the REZ build limit soft constraints reflected a reasonable augmentation to connect each REZ back to the transmission backbone. The costs were customised for each REZ. However, assumptions on costs need to consider likely transmission development options, which in turn depend on the amount of desired access. High transmission access would warrant a different solution to low transmission access. The conversion of appropriate-sized augmentations for an assumed capacity build to a $/MW penalty factor may result in some suboptimal outcomes if significantly different to the assumed development range. This resulted in some amount of iteration to refine either the REZ limit or the penalty factor in response to build decisions in prior iterations.

F.2.3 Short-term time-sequential model (ST model)

The purpose of the ST model was to verify whether or not the candidate plans and associated new energy resources met the reliability and system security requirements of the power system in each scenario. This involved hourly modelling of snapshot years in the planning horizon to examine the supply-demand balance and overall power system dispatch, using detailed transmission constraint sets, and considering unit commitment and strategic bidding behaviour to assess system inertia and fuel offtake that impacts upstream industries such as gas.

To achieve this, the ST model took into consideration hourly profiles of renewable generation and demand, and detailed network capabilities through the development and application of thermal and stability constraint equations representing the existing and planned transmission network. Network constraints were adjusted or revoked where necessary, taking into consideration the transmission network plan.

The ST model was used to provide insights on:

- Feasibility of the DLT model results when considering inter-regional and intra-regional network transfer capacities and limitations.
- Emerging network limitations that could lead to reliability issues or sub-optimal generation dispatch.
- Planned and unplanned generation outage conditions increasing power system reliability risks.
- Inertia level based on unit commitment status.
- Generation mix and fuel offtake that impacts upstream industries such as gas.

For quality assurance purposes, the ST model annual results were compared against the DLT annual outcomes to ensure there are no noticeable differences that may invalidate the investment choices made in the DLT. Comparisons included:

- Verifying that emissions outcomes were consistent between the two models.
- Comparing annual generation production levels across all technology types, to ensure that variable renewable energy resources are not overly constrained due to network limitations that are not captured in the DLT.

Sensitivity analysis was also performed in this step to test the resilience of the plan to, for example, sudden, unannounced closures of coal-fired power stations.

Formulation

The ST model was formulated as a Mixed Integer Programming problem and optimised electricity dispatch at an hourly resolution. The ST model was solved in daily steps (with day-ahead foresight) to produce optimal unit commitment decisions.

Unit commitment optimisation determined which generating units to switch on, and for how long, and influenced fuel consumption (such as gas demand) as well as the level of inertia on the system at any point in time. In addition to dispatch cost, this optimisation also included the generator units' assumed start-up cost, minimum uptime, and minimum stable level. There may be periods when it is optimal to keep generators on at low generation levels, even when making a loss, to avoid the cost of restarting later. AEMO used the 'rounded relaxation' method in PLEXOS® for unit commitment decisions.

A game-theoretic bidding algorithm was incorporated into the objective function, subject to a variety of constraints such as generators' technical capabilities and portfolio composition.

The results of the ST model were validated in the network development outlook model to ensure consistency between the identified REZ intra-regional network augmentations from the DLT and the capabilities of the existing network infrastructure. These insights were referred back to the DLT model in an iterative process to refine the development outlook.

Simulation phases

The ST model was comprised of three interdependent phases, seamlessly run in sequence within PLEXOS®. Designed to better model medium-term to short-term market and power system operation, these phases are:

- **PASA** – allocated generator units' planned maintenance schedule across the year, while maximising plant availability during periods of high demand. The resulting maintenance outage schedule was passed on to both the medium-term schedule and short-term schedule, and reduced the likelihood of planned maintenance to coincide with times of tight supply-demand balance (as system operators would attempt to deliver in the real power system as much as practical).
- **Medium-term schedule** – scheduled generation for generators affected by inter-temporal constraints over a yearly look-ahead period. This included energy limited plant, such as hydroelectric power stations (having annual, seasonal, or monthly limitations), and storage solutions (having hourly or daily energy limitation). A resulting daily energy target was then passed on to the short-term schedule to guide the hourly dispatch.
- **Short-term schedule** – solved for the hourly generation dispatch, one day at a time, to meet consumption while observing power system constraints and chronology of demand and variable generation. This phase used a Monte

Carlo mathematical approach to capture the impact of generator forced outages on market outcomes. The ISP was modelled using a limited number of Monte Carlo iterations, far fewer than would be appropriate for a reliability assessment such as that which is performed for the *Electricity Statement of Opportunities* (ESOO), given the breadth of modelling required across multiple scenarios and sensitivities.

The Nash Cournot bidding model

AEMO used the Nash-Cournot algorithm within PLEXOS® to model strategic behaviour of market participants. This game-theoretic bidding model allowed each generator to strategically adjust the volume they offer to the market such that each portfolio's profit is maximised. Unit commitment decisions were also made, trading off the cost of restarting against the risk of running at a loss for short periods of time if staying on line. This model provides a more realistic approximation of generator dispatch and unit commitment than a short run marginal cost (SRMC) model, which assumes all available generation capacities are offered in the market at each unit's SRMC.

The use of this approach to generator bidding in the ST models increased the reasonable dispatch of the generation mix, particularly the balanced operation of thermal generators, including coal-fired generation and GPG. The improved outcomes allow a more reasonable assessment of fuel usage and inertia available in the system and prediction of the likelihood of frequency stability concerns in the future.

Network limitations

The DLT generation expansion plan was tested in the time-sequential model by using constraint equations that modelled system limits for different system configurations and inter-regional augmentations.

In general, the following constraint equations were used in ISP studies:

- **Thermal** – for managing the power flow on a transmission element so that it does not exceed a rating (either continuous or short-term) under normal conditions or following a credible contingency.
- **Voltage stability** – for managing transmission voltages so that they remain at acceptable levels after a credible contingency.
- **Transient stability** – for managing continued synchronism of all generators on the power system following a credible contingency.
- **Oscillatory stability** – for managing damping of power system oscillations following a credible contingency.
- **Rate of change of frequency (RoCoF) constraints** – for managing the rate of change of frequency following a credible contingency.

The methodology for formulating these constraints is described in detail in AEMO's Constraint Formulation Guidelines[63]. The effects of committed projects and additional network augmentations were implemented as modifications to the network constraint equations that control network power flow.

Inter-regional loss model

In the ST model, transmission losses on inter-regional transfers were modelled using the loss factor equations defined in the List of Regional Boundaries and Marginal Loss Factors report[64]. For most interconnectors, these are defined as a function of regional load and flow.

AEMO uses proportioning factors to assign losses on interconnectors to regions. Operationally, this is used to determine settlement surplus. In market modelling, proportioning factors are used to allocate losses to demand in each region. Proportioning factors are derived from marginal loss factors, as described in AEMO's Market Modelling Methodology report and ISP Assumptions Workbook.[65] Proportioning factors are given in the annual List of Regional Boundaries and Marginal Loss Factors report[66]. For this ISP, the model applied the same proportioning factors to new interconnector developments as are calculated for the existing interconnectors between the same regions[67].

Limitations

The ST simulations were used to validate and verify the appropriateness of the investment decisions made in previous steps of the approach. To do this, analysis was performed on snapshot years (one year in every five years of the

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[63] AEMO. Constraint Formulation Guidelines. Available: http://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/Constraint_Formulation_Guidelines_v10_1.pdf.

[64] AEMO. Loss Factors and Regional Boundaries. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Loss-factor-and-regional-boundaries

[65] AEMO, Market Modelling Methodology and ISP Assumptions Workbook are available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/ISP-Database

[66] AEMO. Regions and Marginal Loss Factors: FY 2017-18. Available: https//aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Loss_Factors_and_Regional_Boundaries/2017/Marginal-Loss-Factors-for-the-2017-18-Financial-Year.pdf

[67] Connection between New South Wales and South Australia via Riverlink assumed a proportioning factor of 0.5

planning horizon, or when a major network augmentation was introduced) with only a single Monte Carlo random generator forced outage pattern and a single historical weather year (2013-14). The simulations therefore should not be considered a robust reliability assessment, and indications of reliability-driven market benefits should not be relied on. Market benefits assessment for a RIT-T for example should examine the benefits of interconnection or non-network solutions with greater consideration of reliability related risks and weather uncertainties.

A further limitation of the model is limited to look-ahead capability. Hydro release and storage charge and discharge decisions are fully optimised by the short-term schedule in PLEXOS®. These decisions require sufficient foresight of the short term to optimally operate these assets. In this modelling, a single day look-ahead was used. For shallow storages, this assumption is not anticipated to materially impact optimal operation, however deeper storages will require greater look-ahead to optimally manage storage volumes, and is something that will be investigated further in the year ahead.

F.2.4 Network development outlook model

The network development outlook model is a power system PSS®E derived model that represents the physical transmission network and all the main transmission elements including individual generating units, transmission lines, transformers, reactive power plant, and loads. Details from the sub-transmission and distribution networks were simplified in this model.

The purpose of this model is to assess power system security of the DLT solution, and assess any emerging network limitations.

Transmission system adequacy was assessed by performing load flow analysis, which assessed power flow between locations where energy is generated and where it is consumed. The transmission network was modelled with continuous rating for studies with all normally in-service plant intact and contingency ratings for studies with potential outage of a single network element or generating unit.

A range of system conditions were studied to identify network constraints and develop network augmentations to deliver generation to the load centre. This included modelling to access high renewable generation from REZs. The following process was applied to identify network constraints and possible solutions:

- In system normal operation with all plant in service, the network was assumed to be able to operate beyond N-1 capacity. To manage overloads immediately following a contingency, renewable generation in a REZ was assumed to be run back by a control scheme to keep the transmission elements within their ratings.
- Where possible, generation within REZs was relocated to remove network constraints.
- Storage solutions were located nearer to solar generation that experienced higher network curtailment, to smooth the use of the transmission system, where available.
- If run-back schemes, relocation, or storage of generation could not address an overload, an appropriate intra-regional transmission system augmentation was chosen to address the overload directly. These were captured within the network constraint equations.

F.3 Renewable Energy Zones

AEMO considered a range of requirements for the selection of REZs. This section presents the methodology applied to determine resource quality, potential wind and solar generation capacity, transmission investment to develop REZs, projected network losses, and diversity of renewable generation within the region and across REZs.

F.3.1 Resource quality

AEMO engaged consultants DNV-GL to provide information on the resource quality for potential REZs. Wind resource quality assessment was based on mesoscale wind flow modelling at a height of 150 m above ground level (typical wind turbine height), while Global Horizontal Irradiance (GHI) and Direct Normal Irradiance (DNI) data from the Bureau of Meteorology (BOM) were used to assess solar resource quality.

AEMO identified wind speeds and solar GHI values inside each of the REZs. This data was used to determine grading of resource quality. For wind generators, the 10% Probability of Exceedance (POE) resource was taken to determine the relative REZ quality, since 50% POE (median) values did not produce enough differentiation between all the different regions. For solar 50% POE values of GHI was taken to determine the grade. The 50% POE GHI values produced sufficient variation between all the REZs to give a meaningful relative grade for solar generation. Table 51 presents grading applied to differentiate REZs based on quality of resources.

Table 51 Grading for quality of resource

Grading	Wind speed (m/s), 10% POE within REZ	Solar GHI (kw/m*) annual average, 50%POE within REZ
A	≥ 8.4	≥ 2000
B	≥ 7.2	≥ 1900
C	≥ 6.6	≥ 1800
D	≥ 6.0	≥ 1700
E	< 6.0	< 1700

* AEMO. http://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Loss_Factors_and_Regional_Boundaries/2017/Forward-Looking-Loss-Factor-Methodology-v70.pdf.

F.3.2 Network capacity and transmission investment

High level network studies were undertaken to identify additional generation which can be accommodated within the existing network. In addition, interconnector expansion options were assessed to identify additional generation that may be enabled by interconnectors developed near or through REZs. The following steps were undertaken:

- Amount of additional generation which can be added within the existing transmission network capability.
- Amount of additional generation which can be added with inter-regional network upgrade options.
- Network expansion to connect REZs to the major transmission network and amount of generation which can be accommodated:
  - Cost estimate of transmission network expansion to connect REZs.
  - Conversion of the cost estimate to a cost per MW for each REZs.

The cost per MW for each REZ was then applied within the ISP market modelling, within the IM and DLT models, as a simple linear cost for development of REZs beyond existing transmission connection capabilities. In this way, each REZ may provide 'free' connection capacity up to existing assumed transmission capabilities. The market model can then expand intra-regional connections to improve transmission access to REZs if the cost of that access is outweighed by the benefits associated with the increased renewable generation that it enables.

F.3.3 Projected network losses

Projected network losses were determined based on the methodology described in AEMO's Forward-Looking Transmission Loss Factors[68]. In particular:

- A complete year of 2017 historical data has been used as a reference.
- Generators representing the REZ were added at connection points.
- Future wind and solar generation and load traces, which were developed PLEXOS® market simulations, were applied.
- Marginal loss factors (MLFs) were calculated for those connection points representing the REZ.

A grading method was used to categorise the average value of current MLF at connection points inside REZs (initial loss factor) and sensitivity of MLFs to additional generation inside REZs (Loss factor robustness). The measure used is the additional generation (MW) that can be added before the MLF drops by 0.05. 0 presents grading applied to differentiate REZs based on loss factors.

[68] AEMO. Methodology for Calculating Forward-Looking Transmission Loss Factors. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Loss-factor-and-regional-boundaries.

Table 52 Grading for loss factors

Grading	Initial loss factor	Loss factor robustness
A	≥ 1.00	≥ 1000
B	≥ 0.95	≥ 750
C	≥ 0.90	≥ 500
D	≥ 0.85	≥ 250
E	≥ 0.80	< 250
F	< 0.80	None

F.3.4 Diversity of renewable generation and demand

Diversity describes whether the REZ resources are available at the same time as each of the other REZs or at different times, using a statistical correlation factor. A low correlation gives a better score. Correlation was determined between the generators in one REZ to generators in each one of the other REZs using a statistical correlation factor to assist in the grading exercise.

Correlation between renewable resource of a REZ and regional demand was also determined. For demand, a positive correlation meaning generation in REZ is more likely to match the demand within the jurisdictional boundary.

One-year REZ generator trace and three different years (2017-18, 2029-30, and 2039-40) of regional demand traces were applied to determine correlation. Table 53 presents grading applied to differentiate REZs based on resource diversity.

Table 53 Grading for resource diversity

Grading	Resource Diversity	Demand matching
A	≤ 0.1	≥ 0.30
B	≤ 0.2	≥ 0.15
C	≤ 0.3	≥ 0.0
D	≤ 0.4	≥ -0.15
E	≤ 0.5	≥ -0.30
F	> 0.5	< -0.30

F.4 System strength assessment – weighted short circuit ratio

Power electronic converters are designed to operate with a minimum short circuit ratio (SCR), below which they can exhibit various forms of instability including:

- Steady-state voltage collapse.
- Inability to ride through a credible fault.

Generators that are connected to the grid via power electronic converters include wind turbine generators, solar inverters, and static VAr compensators. High Voltage Direct Current (HVDC) interconnectors like Basslink also require a minimum SCR to operate properly. SCRs were generally calculated as the ratio of total fault current (in MVA) over MW capacity of generation. When multiple generators utilising power electronic converters are expected to be connected in close proximity, a weighted short circuit ratio (WSCR) calculation was carried out, as described below:

$$WSCR = \frac{\sum_{i}^{N} S_{SCMVAi} * P_{RMWi}}{(\sum_{i}^{N} P_{RMWi})^2}$$

Where S_{SCMVAi} = The fault contribution in MVA of the studied bus

P_{RMWi} = P_{max} of all nearby power electronic converter generators

In reality, the WSCR at a given location will fluctuate depending on generator output, but AEMO has assumed that all power electronic converter generators are at maximum output to obtain a more conservative result. Results also assume no system strength mitigation measures have been taken. The AEMO studies, in Section 5.4.3 of the ISP, categorised system strength based on the maximum capacity of non-synchronous generation that can be connected to a given bus, before the WSCR at that bus reduces to 3.5. The 2018 ISP reports on the expected trend in WSCR of all regions, based on the Neutral scenario.

F.5 NSCAS Assessment

Network Support and Control Ancillary Services (NSCAS) are a non-market ancillary service that may be procured by AEMO or TNSPs to maintain power system security and reliability, and to maintain or increase the power transfer capability of the transmission network.

NSCAS requirements are assessed based on a Quantity Procedure[69] which was developed in consultation with NEM market participants.

A high-level overview of the steps taken to assess NSCAS gaps is given below:

- Review recent operational experiences to manage system security.
- Prepare load flow study cases considering both maximum and minimum regional demand, and only committed generation or transmission network changes, for a five-year outlook horizon.
- Identify potential reactive power shortfalls.
- Identify potential over voltages.
- Identify potential thermal overloads.
- Identify binding constraints[70] that have a market impact of over $50,000 annually, and identify if procuring NSCAS will result in a net market benefit.

[69] AEMO. Network support and control ancillary services procedures and guidelines, available at http://www.aemo.com.au/Electricity/National- Electricity-Market-NEM/Security-and-reliability/Ancillary-services/Network-support-and-control-ancillary-services-procedures-and-guidelines.

[70] Excluding any constraints associated with frequency control ancillary services.

Glossary

This document uses many terms that have meanings defined in the National Electricity Rules (NER). The NER meanings are adopted unless otherwise specified.

Term	Definition
active power	Also known as electrical power. A measure of the instantaneous rate at which electrical energy is consumed, generated or transmitted. In large electric power systems, it is measured in megawatts (MW) or 1,000,000 watts.
annual planning report	An annual report providing forecasts of gas or electricity (or both) supply, capacity, and demand, and other planning information.
augmentation	The process of upgrading the capacity or service potential of a transmission (or a distribution) pipeline.
capacity for reliability	The allocated installed capacity required to meet a region's minimum reserve level (MRL). When met, sufficient supplies are available to the region to meet the Reliability Standard. Capacity for reliability = 10% probability of exceedance (POE) scheduled and semi-scheduled maximum demand + minimum reserve level – committed demand-side participation.
capacity limited	A generating unit whose power output is limited.
committed project	Committed transmission projects include new transmission developments below $5 million that are published in the TNSPs' Annual Planning Reports, or those over $5 million that have completed a Regulatory Investment Test. Committed generation projects include all new generation developments that meet all five criteria specified by AEMO for a committed project.
connection point (electricity)	The agreed point of supply established between network service provider(s) and another registered participant, non-registered customer or franchise customer.
constraint equation	The mathematical expression of a physical system limitation or requirement that must be considered by the central dispatch algorithm when determining the optimum economic dispatch outcome. See also network constraint equation.
contingency	An event affecting the power system that is likely to involve an electricity generating unit's or transmission element's failure or removal from service.
consumer	A person or organisation who engages in the activity of purchasing electricity supplied through a transmission or distribution system to a connection point.
credible contingency	Any outage that is reasonably likely to occur. Examples include the outage of a single electricity transmission line, transformer, generating unit, or reactive plant, through one or two phase faults.
customer	See consumer.
demand	See electricity demand.
distributed energy resources (DER)	Distributed energy resources (DER) can refer to a range of resources behind consumers' electricity meter which produce electricity or actively manage consumer demand. A growing number of Australian energy consumers are using DER, such as solar rooftop systems, battery storage devices, and demand response/management resources such as hot water systems, pool pumps, smart appliances and air conditioning control.
distribution network	A network which is not a transmission network.
electrical energy	Energy can be calculated as the average electrical power over a time period, multiplied by the length of the time period. Measured on a sent-out basis, it includes energy consumed by the consumer load, and distribution and transmission losses. In large electric power systems, electrical energy is measured in gigawatt hours (GWh) or 1,000 megawatt hours (MWh).

Term	Definition
electrical power	Electrical power is a measure of the instantaneous rate at which electrical energy is consumed, generated or transmitted. In large electric power systems, it is measured in megawatts (MW) or 1,000,000 watts. Also known as active power.
electricity demand	The electrical power requirement met by generating units. The Electricity Statement of Opportunities (ESOO) reports demand on a generator-terminal basis, which includes: • The electrical power consumed by the consumer load. • Distribution and transmission losses. • Power station transformer losses and auxiliary loads. • The ESOO reports demand as half-hourly averages.
energy	See electrical energy.
gas-powered generation (GPG)	Gas-fired power stations convert the heat energy from the combustion of natural gas into electricity. There are two main types of power stations used to convert natural gas into electricity – open cycle gas turbine (OCGT) and combined cycle gas turbine (CCGT).
generating system	A system comprising one or more generating units that includes auxiliary or reactive plant that is located on the generator's side of the connection point.
generating unit	The actual generator of electricity and all the related equipment essential to its functioning as a single entity.
generation	The production of electrical power by converting another form of energy in a generating unit.
generation capacity	The amount (in megawatts (MW)) of electricity that a generating unit can produce under nominated conditions. The capacity of a generating unit may vary due to a range of factors. For example, the capacity of many thermal generating units is higher in winter than in summer.
generation expansion plan	A plan developed using a special algorithm that models the extent of new entry generation development based on certain economic assumptions.
generator	A person who engages in the activity of owning, controlling or operating a generating system that is connected to, or who otherwise supplies electricity to, a transmission or distribution system and who is registered by AEMO as a generator under Chapter 2 (of the NER) and, for the purposes of Chapter 5 (of the NER), the term includes a person who is required to, or intends to register in that capacity.
inertia	Produced by synchronous generators, inertia dampens the impact of changes in power system frequency, resulting in a more stable system. Power systems with low inertia experience faster changes in system frequency following a disturbance, such as the trip of a generator.
installed capacity	Refers to generating capacity (in megawatts (MW)) in the following context: • A single generating unit. • A number of generating units of a particular type or in a particular area. • All of the generating units in a region.
interconnector	A transmission line or group of transmission lines that connects the transmission networks in adjacent regions.
interconnector flow	The quantity of electricity in MW being transmitted by an interconnector.
Large-scale Renewable Energy Target (LRET)	A federal government target that 33,000 GWh of large-scale generation must come from renewable energy sources by 2020.
limitation (electricity)	Any limitation on the operation of the transmission system that will give rise to unserved energy (USE) or to generation re-dispatch costs.
load	A connection point or defined set of connection points at which electrical power is delivered to a person or to another network, or the amount of electrical power delivered at a defined instant at a connection pint, or aggregated over a defined set of connection points.
maximum demand	The highest amount of electrical power delivered, or forecast to be delivered, over a defined period (day, week, month, season, or year) either at a connection point, or simultaneously at a defined set of connection points.
National Electricity Law	The National Electricity Law (NEL) is a schedule to the National Electricity (South Australia) Act 1996, which is applied in other participating jurisdictions by application acts. The NEL sets out some of the key high-level elements of the electricity regulatory framework, such as the functions and powers of NEM institutions, including AEMO, the AEMC, and the AER.
National Electricity Market (NEM)	The wholesale exchange of electricity operated by AEMO under the NER.

Term	Definition
National Electricity Rules (NER)	The National Electricity Rules (NER) describes the day-to-day operations of the NEM and the framework for network regulations. See also National Electricity Law.
national transmission grid	See national transmission flow paths.
National Transmission Planner	AEMO acting in the performance of National Transmission Planner functions.
National Transmission Planner (NTP) functions	Functions described in section 49(2) of the National Electricity Law.
network	The apparatus, equipment, plant and buildings used to convey, and control the conveyance of, electricity to consumers (whether wholesale or retail) excluding any connection assets. In relation to a network service provider, a network owned, operated or controlled by that network service provider.
network capability	The capability of the network or part of the network to transfer electricity from one location to another.
network congestion	When a transmission network cannot accommodate the dispatch of the least-cost combination of available generation to meet demand.
network constraint equation	A constraint equation deriving from a network limit equation. Network constraint equations mathematically describe transmission network technical capabilities in a form suitable for consideration in the central dispatch process. See also 'constraint equation'.
network limit	Defines the power system's secure operating range. Network limits also take into account equipment/network element ratings.
network limitation	Network limitation describes network limits that cause frequently binding network constraint equations, and can represent major sources of network congestion. See also network congestion.
network service	Transmission service or distribution service associated with the conveyance, and controlling the conveyance, of electricity through the network.
network service provider (NSP)	A person who engages in the activity of owning, controlling or operating a transmission or distribution system and who is registered by AEMO as a network service provider under Chapter 2 (of the NER).
non-credible contingency	Any outage for which the probability of occurrence is considered very low. For example, the coincident outages of many transmission lines and transformers, for different reasons, in different parts of the electricity transmission network.
non-network option	An option intended to relieve a limitation without modifying or installing network elements. Typically, non-network options involved demand-side participation (including post contingent load relief) and new generation on the load side for the limitation.
power	See 'electrical power'.
power station	In relation to a generator, a facility in which any of that generator's generating units are located.
power system	The National Electricity Market's (NEM) entire electricity infrastructure (including associated generation, transmission, and distribution networks) for the supply of electricity, operated as an integrated arrangement.
power system reliability	The ability of the power system to supply adequate power to satisfy customer demand, allowing for credible generation and transmission network contingencies.
power system security	The safe scheduling, operation, and control of the power system on a continuous basis in accordance with the principles set out in clause 4.2.6 (of the NER).
reactive energy	A measure, in VAr-hour (VArh), of the alternating exchange of stored energy in inductors and capacitors, which is the time-integral of the product of voltage and the out-of-phase component of current flow across a connection point.
reactive power	The rate at which reactive energy is transferred. Reactive power, which is different to active power, is a necessary component of alternating current electricity. In large power systems it is measured in MVAr (1,000,000 volt-amperes reactive). It is predominantly consumed in the creation of magnetic fields in motors and transformers and produced by plant such as: • Alternating current generators. • Capacitors, including the capacitive effect of parallel transmission wires. • Synchronous condensers. Management of reactive power is necessary to ensure network voltage levels remains within required limits, which is in turn essential for maintaining power system security and reliability.

Term	Definition
region	An area determined by the AEMC in accordance with Chapter 2A (of the NER), being an area served by a particular part of the transmission network containing one or more major load centres of generation centres or both.
Regulatory Investment Test for Transmission (RIT-T)	The test developed and published by the AER in accordance with clause 5.6.5B, including amendments. The test is to identify the most cost-effect option for supplying electricity to a particular part of the network. It may compare a range of alternative projects, including, but not limited to, new generation capacity, new or expanded interconnection capability, and transmission network augmentation within a region, or a combination of these.
reliability	The probability that plant, equipment, a system, or a device, will perform adequately for the period of time intended, under the operating conditions encountered. Also, the expression of a recognised degree of confidence in the certainty of an event or action occurring when expected.
rooftop photovoltaic (PV)	Includes both residential and commercial photovoltaic installations that are typically installed on consumers' rooftops.
scenario	A consistent set of assumptions used to develop forecasts of demand, transmission, and supply.
scheduling	The process of scheduling nominations and increment/decrement offers, which AEMO is required to carry out in accordance with the NGR, for the purpose of balancing gas flows in the transmission system and maintaining the security of the transmission system.
security	Security of supply is a measure of the power system's capacity to continue operating within defined technical limits even in the event of the disconnection of a major power system element such as an interconnector or large generator.
substation	A facility at which two or more lines are switched for operational purposes. May include one or more transformers so that some connected lines operate at different nominal voltages to others.
supply	The delivery of electricity.
transmission network	A network within any participating jurisdiction operating at nominal voltages of 220 kV and above plus: • Any part of a network operating at nominal voltages between 66 kV and 220 kV that operates in parallel to and provides support to the higher voltage transmission network. • Any part of a network operating at nominal voltages between 66 kV and 220 kV is deemed by the Australian Energy Regulator (AER) to be part of the transmission network.