SECOND TASMANIAN INTERCONNECTOR

REPORT FOR THE TASMANIAN ENERGY TASKFORCE

January 2017
IMPORTANT NOTICE

Purpose
AEMO has prepared this document to provide input into the Tasmanian Taskforce’s report into the feasibility of a second Bass Strait interconnector. It reflects market and power system modelling and analysis based on information available to AEMO as at 14 October 2016, unless another date is specified.

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EXECUTIVE SUMMARY

AEMO has produced this report at the request of the Department of the Environment and Energy, to support the Tasmanian Energy Taskforce (the Taskforce) in its feasibility study into whether a second Tasmanian interconnector could improve Tasmania’s energy security and facilitate renewable energy investment. It summarises AEMO’s market and power system modelling and analysis, conducted to provide input into the Taskforce’s final report.

As the national transmission planner, AEMO has taken a strategic approach to this assessment, focusing on efficient development across the National Electricity Market (NEM) in the long-term interests of consumers. This includes consideration of how the NEM is likely to evolve in the future and what effects a second Tasmanian interconnector, or other interconnectors, would have on this evolution and power system operation.

AEMO has assessed:

- The market benefits of a second interconnector between Tasmania and Victoria.
- The network augmentations and other power system changes required to facilitate the concurrent development of a second interconnector and substantial additional wind generation in Tasmania.
- The potential benefits of further interconnector developments between Victoria and South Australia, and the concurrent development of a second Bass Strait interconnector.

The analyses in this report identify the costs and market benefits associated with increased interconnection at a high level, and should not be interpreted as satisfying the requirements of a complete regulatory investment test for transmission (RIT-T) process.

AEMO’s key observations

- **Assuming neutral economic growth, a second interconnector with Tasmania is projected to deliver gross market benefits of $361 million over the next 20 years to 2035–36 by:**
  - Delivering $85 million savings in fuel and variable operating and maintenance costs, due to production from hydro and wind generation in Tasmania primarily displacing higher-cost natural gas generation in the mainland NEM.
  - Facilitating the gradual development of additional renewable generation in Tasmania (mainly wind) to support supply changes in the mainland ($6 million in reduced environmental scheme costs).
  - Deferring the need for gas-powered generation (GPG) investments in the mainland NEM ($134 million market benefits).
  - Reducing reliance on voluntary demand curtailment and involuntary load shedding ($87 million market benefits).
  - Delivering $48 million of market benefits (including reliability benefits) in the event that the Basslink interconnector was out of service for an entire year.

- **Over the same period, the annualised cost of the second Bass Strait interconnector is estimated to be around $341 million.¹ With projected net market benefits of just $20 million, further analysis would be required to justify this investment in the long-term interest of consumers.

- **Greater interconnection delivers synergies.** Projected net market benefits of a second Bass Strait interconnector increase if an additional South Australian interconnector is built first. This is mainly because the development of more interconnection uses the diversity of renewable generation across the regions more effectively. It reduces the need for higher-cost gas

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¹ Total cost is estimated to be about $940 million, with an economic life of 50 years and weighted average cost of capital of 8.76%. Assuming a 7% social discount rate, the $341 million cost represents the net present value (NPV) of annualised costs for the period to 2035–36, with the interconnector operational from July 2025.
generation by allowing renewable generation in one region to complement the intermittency of renewable generation in another region.

- **The market benefits of a second Bass Strait interconnector are not robust.** The interconnector is only economically justified in scenarios where it delivers capital deferral benefits in addition to fuel cost savings. If future operational demand is low, or emerging technologies such as utility-scale batteries become widespread, the ability for the interconnector to defer new generation builds diminishes.

- **Building additional renewable generation in Tasmania may lead to oversupply.** Building new renewable generation in Tasmania (1,200 megawatts (MW) of wind), timed to coincide with commissioning of the second Bass Strait interconnector, would not increase projected market benefits. New renewable generation is projected to be developed in Victoria to meet the proposed Victorian Renewable Energy Target (VRET)\(^2\), in which case any additional generation from Tasmania would lead to oversupply in the southern regions (Victoria, Tasmania, and South Australia). This would either drive further generation withdrawals or require stronger interconnection between Victoria and New South Wales.

- **Additional power system security support is not needed in Victoria.** While a second Bass Strait Interconnector may provide power system security benefits such as frequency control ancillary services (FCAS), these support services are adequately provided by existing generators in Tasmania and Victoria.

- **Low system strength and inertia may need to be addressed in Tasmania.** With increased interconnection and greater penetration of renewable generation, Tasmania's hydro generators will be able to operate more flexibly. Therefore, under certain conditions, there may be fewer hydro units online to provide system inertia and system strength in Tasmania. This could be addressed by using existing hydro and GPG operating as synchronous condensers, or implementing new network or non-network solutions such as new synchronous condensers, fast frequency services from wind generation, and battery storage.

- **Network investment will be needed in Tasmania.** A second interconnector would require a new 220 kilovolt (kV) double circuit transmission line from Sheffield to Smithton (in Tasmania) and connection to the existing 220 kV Victorian transmission network at Tyabb (in Victoria), all of which has been included in the projected cost of the interconnector. There are no other material differences in intra-regional transmission network augmentation needs across the NEM, with or without a second Bass Strait interconnector.

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**Modelling scenarios**

AEMO has modelled additional interconnection and wind generation, as requested by the Taskforce, using three scenarios, Neutral, Low Grid Demand, and ‘45% Emissions Reduction’. These scenarios are same as those being modelled for AEMO’s annual *National Transmission Network Development Plan (NTNDP)*\(^3\), which provides an independent, strategic view of the efficient development of the NEM transmission grid over a 20-year planning horizon.

Both economic growth scenarios assume the COP21 emission reduction commitment and the VRET are achieved. The ‘45% Emissions Reduction’ scenario assumes that greenhouse gas emissions in the electricity sector are reduced by 45% below 2005 levels by 2030.

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A number of case studies have been considered for all three scenarios, with each giving insight into the potential value provided by a particular interconnector development.

Over the 20-year modelling horizon, significant change to the NEM generation mix is expected as various policies at state and federal level encourage increased uptake of renewable generation. This is while demand is forecast to remain relatively flat. The magnitude of the changing supply mix differs between the three scenarios, due to differences in demand outlooks:

- The Neutral scenario produces an evolving supply mix, with increased wind and solar projects offsetting retirements of coal generators, particularly in New South Wales and Victoria. GPG augments renewable capacity to maintain system reliability in this scenario.
- The 45% Emissions Reduction scenario projects an accelerated NEM evolution, with more synchronous generation withdrawals and greater renewable generation penetration.
- The Low Grid Demand scenario projects a more rapid retirement of coal capacity on economic grounds, as electricity consumption reduces from current levels. Reduced opportunities are projected to exist for long-term renewable developments compared to the neutral scenario, although some GPG would still be required to replace lost firm capacity from retired coal-fired generation.

Under all three scenarios, there are projected net market benefits associated with increased capability of the existing VIC–NSW and QNI interconnectors in the 2020s ($123 million for the Neutral scenario, $86 million for the Low Grid Demand scenario, and $281 million for the 45% Emissions Reduction scenario). These augmentation options are included in all analyses including the ‘Base case’ in this report.

Results and insights

The sections below discuss the results of AEMO’s analysis, across:

- The projected effects of interconnection development under the Neutral, Low Grid Demand, and 45% Emission Reduction scenarios.
- An assessment of requirements for transmission augmentation in Tasmania, as well as any material changes to the mainland transmission network, with and without a second Bass Strait interconnector.
- Potential system security issues in Tasmania or Victoria associated with the case studies.

Projected effects of alternate interconnection development options

Neutral scenario

This table summarises some critical points to note under Neutral scenario case studies, relative to the case where there are no interconnector upgrades.

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4 Alternating current interconnector between Queensland and New South Wales.
Table 1 Case study insights for the Neutral scenario, relative to no interconnector upgrades

<table>
<thead>
<tr>
<th>Case study</th>
<th>NPV of gross market benefits to 2035–36</th>
<th>NPV of annualised cost to 2035–36</th>
<th>Net Market Benefit</th>
<th>Incremental net market benefit (compared to Base case)</th>
<th>Key insights</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base case</td>
<td>$170 M</td>
<td>$47 M</td>
<td>$123 M</td>
<td>-</td>
<td>• The upgrades to QNI and VIC–NSW interconnectors provide net market benefits primarily through fuel cost savings.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>• These augmentations supplement New South Wales’ supply as existing generation withdraws.</td>
</tr>
<tr>
<td>Second Bass Strait interconnector +</td>
<td>$531 M</td>
<td>$387 M</td>
<td>$143 M</td>
<td>$20 M</td>
<td>• This interconnector development is projected to provide capital deferral benefits and reduce the need for voluntary demand curtailment.</td>
</tr>
<tr>
<td>Base case upgrades</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>• It will deliver modest fuel cost savings, given greater flexibility to operate Tasmanian hydro generation to offset high-cost plant at peak times on the mainland.</td>
</tr>
<tr>
<td>Additional South Australian Interconnector + Base case upgrades</td>
<td>$595 M</td>
<td>$335 M</td>
<td>$260 M</td>
<td>$136 M</td>
<td>• This interconnector development is projected to deliver fuel cost savings, given greater ability to renewable resources in South Australia at times when GPG would otherwise be required. It will also deliver system security benefits by reducing the risk of a widespread black system in South Australia, following the unanticipated loss of generation within the region.</td>
</tr>
<tr>
<td>Second Bass Strait interconnector and</td>
<td>$978 M</td>
<td>$676 M</td>
<td>$302 M</td>
<td>$179 M</td>
<td>• The development of both interconnectors provides the most benefits, as the increased geographic diversification of resources has a compounding effect, resulting in the lowest fuel costs of any case studied.</td>
</tr>
<tr>
<td>South Australian link + Base case upgrades</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>• This case study leads to an increase in South Australia wind production, increased flexibility in Tasmanian hydro production, and capital deferral.</td>
</tr>
<tr>
<td>Second Bass Strait interconnector +</td>
<td>$377 M</td>
<td>$387 M</td>
<td>-$11 M</td>
<td>-$134 M</td>
<td>• The development of the interconnector and wind in Tasmania delivers modest fuel cost savings, with greater capacity for Tasmanian renewables (hydro and wind) to meet load on the mainland.</td>
</tr>
<tr>
<td>plus accelerated development of wind</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>• The case comes at a higher overall build cost however (for both generation capacity and the interconnector itself) than the Base case, as the case both hastens and increases overall renewable build in Tasmania.</td>
</tr>
<tr>
<td>generation in Tasmania + Base case</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>upgrades</td>
<td></td>
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<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

The analysis indicates that synergies are achieved through greater interconnection, highlighting the importance of a national, strategic coordinated approach to planning. The combined net market benefits of both an additional South Australian interconnector and the second Bass Strait interconnector are likely to be greater than the sum of their separate effects. The development of more interconnection uses the diversity of renewable generation across the regions more effectively. It reduces the need for higher–cost gas generation by allowing renewable generation in one region to back up renewable generation in another region.

This analysis includes an estimate of the market benefits associated with:

- More efficient generation dispatch resulting in fuel cost savings.
- Changes in potential Large-scale Renewable Energy Target (LRET) penalty costs.
• Capital cost savings due to deferred investments.
• Reduced maintenance costs.
• Maintaining connection with the mainland in the event of a prolonged (year-long) loss of Basslink.

It does not include any potential benefits related to competition, or any potential change in ancillary service costs. To assess these type of benefits, more detailed assessment would be necessary, and is out of scope for this review.

45% Emissions Reduction scenario

The projected value of a second Bass Strait interconnector is lower in the 45% Emissions Reduction scenario. Despite delivering greater fuel cost savings in this scenario, due to an accelerated retirement of brown coal generation, the interconnection provides minimal capital deferral benefits. Increased uptake of large-scale battery storage in all cases dampens the benefit of the additional capacity access provided via the interconnector.

Assuming the interconnector was operational by 2025–26, the net present value (NPV) of gross market benefits to 2035–36 is projected to be about $284 million, compared to the projected annualised cost of the interconnector over the 10-year period of $341 million.

Similar to the Neutral scenario, the highest net market benefits are projected if an additional South Australian interconnector is built before the second Bass Strait interconnector.

Low Grid Demand scenario

Under the Low Grid Demand scenario, AEMO’s analysis indicates negative net market benefits, as the cost of the interconnector may not be recovered through fuel cost savings and capital deferral benefits. The capital deferral benefits are not as high in the Low Grid Demand scenario, as there is less requirement to build new generation.

Assuming the interconnector is operational by 2025–26, the NPV of gross market benefits to 2035–36 is projected to be about $194 million, compared to the projected annualised cost of the interconnector over the 10-year period of $341 million.

The projected value of building an additional South Australian interconnector before the second the Bass Strait interconnector is also lower in this scenario.

Transmission outlook

Transmission network expansion for new connections

A second Bass Strait interconnector is modelled from July 2025, with 600 MW transfer capacity and connection points at Smithton (Tasmania) and Tyabb (Victoria). High voltage direct current (HVDC) based on voltage source converter (VSC) technology was considered for modelling of the second interconnector.

• The existing transmission network at Tyabb could accommodate connection of a second Bass Strait interconnector.
• The Tasmanian transmission network would require a new double circuit 220 kV transmission line from Sheffield to Smithton for the connection of second Bass Strait interconnector.
• The projected cost of a new double circuit 220 kV line from Sheffield to Smithton and a new 220 kV substation near Smithton and connection to Victorian transmission network at Tyabb were included in the $940 million estimated project cost.

Network limitations in Tasmania

The following potential network limitations have been identified. Market benefits associated with relieving these limitations have not been assessed in this study:

• In the Neutral, Low Grid Demand, and 45% Emissions Reduction scenarios, a projected economic dispatch limitation was identified on the Sheffield–Palmerston 220 kV circuit, as it would exceed continuous ratings during system normal operation. In the Base case, this network constraint is
projected to be driven by high generation in North-West and West Coast Tasmania. In the second Bass Strait interconnector case study, this constraint is projected to be driven by high generation in Southern Tasmania, coupled with high export via the second interconnector.

- In the Neutral and 45% Emissions Reduction scenarios for all case studies, a projected economic dispatch limitation was also identified on the Sheffield–Georgetown 220 kV circuit, as it would exceed continuous ratings during system normal operation. This projected constraint is mainly driven by high generation from North-West and West Coast Tasmania, coupled with high export to Victoria via the existing Basslink interconnector.

- Options to address projected economic dispatch thermal limitations would include line uprating of existing 220 kV circuits for a higher thermal rating, a second Sheffield–Palmerston 220 kV circuit, and a third Sheffield–Georgetown 220 kV circuit.

- No network thermal limitations were identified to meet maximum demand, in either the Neutral or Low Grid Demand scenarios.

Network limitations in the mainland NEM

The deferral of peaking generation capacity resulting from a second Bass Strait interconnector is not expected to materially change projected transmission network augmentation requirements in the mainland NEM.

Power system security

Greater interconnection with the mainland would provide hydro generation with more flexibility to generate at times of greater value – that is, during high demand periods or when renewable generation was low. This increased use at times of high value would likely lead to conservation of water during low-value periods, potentially increasing the number of periods when no hydro plant was generating. Additional wind generation in Tasmania is projected to amplify this change in hydro use.

Lack of hydro units generating at certain times may lead to power system security challenges such as reduced system inertia, FCAS capability, and system strength in the Tasmanian power system. As a consequence, frequency and voltage control could be expected to become more challenging in Tasmania. For all scenarios, possible solutions to address these power system security challenges include:

- A number of existing hydro generators and GPG in Tasmania could provide inertia services and system strength services by operating in synchronous condenser mode. There are currently no market-based incentives for these services.

- There is a market mechanism to procure adequate FCAS capability through NEMDE (the NEM Dispatch Engine). This mechanism would result in rescheduling generation in Tasmania and Bass Strait interconnector transfers, to increase FCAS availability in Tasmania.

The mainland is interconnected by an alternating current network, and under normal operating conditions there should continue to be sufficient synchronous generators (considering potential retirements) to provide the necessary FCAS, without the need for additional interconnection.

Low Grid Demand scenario assumptions include increasing probability of retirement of a number of large industrial loads in the NEM, including in Tasmania.5 In this scenario, the lack of available large industrial load is projected to affect the existing frequency control special protection scheme (FCSPS) and lead to frequency control issues. To meet this projected challenge without a second Bass Strait interconnector, import from Victoria to Tasmania would need to be reduced. With FCSPS not in service, a second interconnector could improve frequency control and allow increased imports from Victoria to Tasmania. This would increase the market benefit of the second Bass Strait interconnector in the Low Grid Demand scenario.

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CONTENTS

EXECUTIVE SUMMARY

1. INTRODUCTION
   1.1 Studies carried out by AEMO

2. KEY ASSUMPTIONS AND METHODOLOGY
   2.1 Key Tasmanian assumptions
   2.2 Market modelling methodology

3. GENERATION OUTLOOK
   3.1 Neutral scenario
   3.2 45% Emissions Reduction scenario
   3.3 Low Grid Demand scenario

4. MARKET BENEFIT ANALYSIS
   4.1 Neutral scenario
   4.2 ‘45% Emissions Reduction’ scenario
   4.3 Low Grid Demand scenario

5. TASMANIAN TRANSMISSION OUTLOOK
   5.1 Transmission limitations
   5.2 Special Control Schemes in Tasmania
   5.3 Network limitations in the mainland NEM
   5.4 Emerging system security challenges

6. CONCLUSIONS

MEASURES AND ABBREVIATIONS

Units of measure
Abbreviations

GLOSSARY

TABLES

Table 1 Case study insights for the Neutral scenario, relative to no interconnector upgrades
Table 2 AEMO modelling scenarios
Table 3 Interconnector options considered
Table 4 Case studies
Table 5 Possible location and size of new wind and pumped hydro generation in Tasmania
Table 6 Storage energy (in GWh) of the three types of generation in Tasmania
Table 7 Market benefits of various interconnector options under the Neutral scenario – summary
Table 8 Market benefits of various interconnector options under the Neutral scenario – benefit detail
Table 9 Market benefits of various interconnector options under the 45% Emissions Reduction scenario – summary
Table 10 Market benefits of various interconnector options under the 45% Emissions Reduction Scenario – benefit detail
Table 11 Market benefits of various interconnector options under the Low Grid Demand scenario – summary
Table 12 Market benefits of various interconnector options under the Low Grid Demand Scenario – benefit detail
Table 13 Potential economic dispatch limitations

FIGURES

Figure 1 Second Bass Strait interconnector route and connection points
Figure 2 Second Bass Strait interconnector – electrical connection
Figure 3 Location of new wind generation and pumped hydro station
Figure 4 Projected total installed capacity by fuel type (Neutral scenario – Base case)
Figure 5 Projected total installed capacity of large scale intermittent renewable generation, by region (Neutral scenario – Base case)
Figure 6 Projected total installed capacity in Tasmania by fuel type (Neutral scenario – Base case)
Figure 7 Wind installation differences for Tasmania across each case study (Neutral scenario)
Figure 8 OCGT installed capacity differences for the NEM
Figure 9 CCGT development differences for the NEM for each case study
Figure 10 Total installed capacity by fuel type to 2035–36, 45% Emissions Reduction scenario
Figure 11 Projected total installed capacity of large scale intermittent renewable generation, by region (45% Emissions Reduction scenario – Base case)
Figure 12 Projected total installed capacity in Tasmania by Fuel Type (45% Emissions Reduction scenario – Base case)
Figure 13 Wind installation differences for Tasmania across each case study (45% Emissions Reduction scenario)
Figure 14 OCGT development differences for the NEM for each case study (45% Emissions Reduction scenario)
Figure 15 CCGT development differences for the NEM for each case study (45% Emissions Reduction scenario)
Figure 16 Battery storage development differences for the NEM for each case study (45% Emissions Reduction scenario)
Figure 17 Total installed capacity by fuel type to 2035–36, Low Grid Demand scenario – Base case
Figure 18 Projected total installed capacity of large scale intermittent renewable generation, by region (Low Grid Demand scenario – Base case)
Figure 19 Projected total installed capacity in Tasmania by fuel type (Low Grid Demand scenario – Base case)
Figure 20 Wind installation differences for Tasmania across each case study (Low Grid Demand scenario)
Figure 21 OCGT development differences for the NEM for each case study (Low Grid Demand scenario)
Figure 22 CCGT development differences for the NEM for each case study (Low Grid Demand scenario)
Figure 23 Average wind farm operation per region, by time of day
Figure 24 Average wind farm operation per region, by month
Figure 25 Generation duration curve for hydro generation in Tasmania, pre and post-augmentation
Figure 26 Average generation by time of day for hydro facilities in Tasmania
1. INTRODUCTION

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The analyses identify the costs and market benefits associated with increased interconnection at a high level, and should not be interpreted as satisfying the requirements of a complete regulatory investment test for transmission (RIT-T) process.

1.1 Studies carried out by AEMO

AEMO publishes a National Transmission Network Development Plan (NTNDP) annually that provides an independent, strategic view of the efficient development of the NEM transmission grid over a 20-year planning horizon. AEMO has built on the studies carried out for this publication to conduct further studies in support of the objectives of the Tasmanian taskforce.

1.1.1. Scenarios considered

The modelling scenarios considered by AEMO are shown in Table 2.

All scenarios assume that the COP21 emission reduction commitment and the Victorian Renewable Energy Target (VRET) are achieved. The Neutral and Low Grid Demand scenarios assume a pro-rata share of the COP21 target is borne by electricity consumers. However, the 45% Emissions Reduction scenario assumes a stronger carbon reduction target from the stationary energy sector. Operational consumption projections in all scenarios are from the 2016 National Electricity Forecasting Report (NEFR). More detail about the scenarios, including key inputs and assumptions, is discussed in Chapter 2.

Table 2 AEMO modelling scenarios

<table>
<thead>
<tr>
<th>Modelling scenario</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Neutral scenario</td>
<td>Assumes operational consumption changes in line with the 2016 NEFR Neutral demand sensitivity.</td>
</tr>
<tr>
<td>Low Grid Demand scenario</td>
<td>Assumes technology cost reductions leading to greater growth of small distributed generation sources and energy efficiency uptake and corresponding low operational consumption growth, consistent with the Weak demand sensitivity of the 2016 NEFR.</td>
</tr>
<tr>
<td>45% Emissions Reduction scenario</td>
<td>Assesses changes in the development of the electricity market should higher carbon abatement be targeted from the stationary energy sector (reduce carbon emissions by 45% below 2005 levels by 2030). Otherwise, consistent with the NTNDP Neutral scenario.</td>
</tr>
</tbody>
</table>

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6 COP21 commitment – Australia set a target at the Paris 21st Conference of Parties (COP21) to reduce carbon emissions by 26% to 28% below 2005 levels by 2030. The Council of Australian Governments (COAG) Energy Council has agreed that the contribution of the electricity sector should be consistent with national emission reduction targets.


1.1.2. Interconnector development case studies

The development of additional interconnectors will likely lead to changes in evolution of the supply side of the market. With increased opportunities to export electricity, regions of high renewable resource availability may develop more generation than would be otherwise economically justifiable if constrained due to transmission limitations. In this way, interconnectors serve to exploit the geographic diversity of intermittent generation sources, leading to efficient generation siting decisions from a resource perspective.

A number of possible augmentations to increase interconnection in the NEM were considered in AEMO’s studies, informed by co-optimised generation and transmission expansion modelling. A summary of the options selected through modelling for inclusion in case studies is shown in Table 3.

### Table 3 Interconnector options considered

<table>
<thead>
<tr>
<th>Interconnector</th>
<th>Forward direction</th>
<th>Increase from present notional limit (MW)</th>
<th>Increase from present notional limit (MW)</th>
<th>Timing in Neutral</th>
<th>Timing in Low Grid Demand</th>
<th>Timing in 45% Emissions Reduction</th>
</tr>
</thead>
<tbody>
<tr>
<td>QNI&lt;sup&gt;9&lt;/sup&gt;</td>
<td>NSW–QLD</td>
<td>450</td>
<td>300</td>
<td>2028–29</td>
<td>2026–27</td>
<td>2025–26</td>
</tr>
<tr>
<td>VIC–NSW&lt;sup&gt;10&lt;/sup&gt;</td>
<td>VIC–NSW</td>
<td>170</td>
<td>0</td>
<td>2029–30</td>
<td>2023–24</td>
<td>2029–30</td>
</tr>
<tr>
<td>Second Bass Strait interconnector</td>
<td>TAS–VIC</td>
<td>600</td>
<td>600</td>
<td>2025–26</td>
<td>2025–26</td>
<td>2025–26</td>
</tr>
</tbody>
</table>

Table 4 shows the modelled case studies considered for each of the three defined scenarios. Each case study investigated the impact of various combinations of interconnector developments, as outlined in the table. The ‘2BSI + 1200MW wind’ case study was designed to explicitly test whether the benefits of a second Bass Strait interconnector increased if more renewable generation was built in Tasmania.

### Table 4 Case studies

<table>
<thead>
<tr>
<th>Case study</th>
<th>Abbreviation</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Upgrade QNI &amp; VIC–NSW interconnectors (‘Base case’)</td>
<td>Base case</td>
<td>Incremental augmentation to the existing QNI and VIC–NSW interconnectors</td>
</tr>
<tr>
<td>Second Bass Strait interconnector</td>
<td>2BSI</td>
<td>Introduction of a second TAS–VIC interconnector as well as the augmentations identified in the Base case</td>
</tr>
<tr>
<td>Additional South Australian interconnector</td>
<td>New SA Link</td>
<td>Introduction of an additional South Australian interconnector as well as the augmentations identified in the Base case</td>
</tr>
<tr>
<td>Both second Bass Strait IC and additional interconnection with SA</td>
<td>New SA Link + 2BSI</td>
<td>Introduction of both of the above proposed interconnectors as well as the augmentations identified in the Base case</td>
</tr>
<tr>
<td>Second Bass Strait Interconnector with additional Tasmanian wind generation</td>
<td>2BSI + 1200MW wind</td>
<td>Introduction of a second TAS–VIC interconnector and concurrent build of 1,200 MW of wind generation in Tasmania as well as the augmentations identified in the Base case</td>
</tr>
</tbody>
</table>


2. KEY ASSUMPTIONS AND METHODOLOGY

This chapter describes the approach and key assumptions used by AEMO in conducting the studies described in this report.

2.1 Key Tasmanian assumptions

2.1.1 A second Bass Strait interconnector

This report investigated a 600 MW transfer capacity of second Bass Strait interconnector. A feasible option to transfer 600 megawatts (MW) over about 300 km distance is high voltage direct current (HVDC) technology. This report considers HVDC with voltage source converter (VSC) technology. This technology can operate with low system strength, manage over voltages, and provide continuous frequency support services much better than the existing HVDC line-commutated current-sourced converter (LCC) technology of Basslink.

A number of routes are possible for the second HVDC submarine cable and connection points in Victoria and Tasmania. In this high level study, a route between Smithton (in North-West Tasmania) and Tyabb (in South-East Victoria) has been modelled. Smithton has large wind power generation potential with a relatively high capacity factor compared to wind power generation from other locations. Tyabb is closer to the major load centre in Victoria.

Figure 1 shows the route of the modelled second interconnector. A number of separate routes are possible for connection of second interconnector. A detailed RIT-T type of study may consider other possible routes and connection points.
An additional 220 kilovolt (kV) double circuit transmission line Sheffield to Smithton (approximately 130 km) would be required to facilitate connection of a second Bass Strait interconnector. This 220 kV line also needs to accommodate a large amount of wind power generation in North-West Tasmania. A new substation and converter station would be required at Smithton or in North-West Tasmania. The existing 220 kV network in Victoria can accommodate additional transfer between Tasmania and Victoria. A new converter station would be required at Tyabb or in the vicinity.

Figure 2 shows the network configuration for connection of the proposed second Bass Strait interconnector.
2.1.2 New generation locations in Tasmania

To minimise generation and transmission network costs, new generation is assumed to be located efficiently, considering spare network capacity, network connection costs and the quality of the local wind and solar resources (or availability of fuel sources for thermal plants). AEMO consulted TasNetworks and Hydro Tasmania for possible location and size of these new wind power generation and hydro storage pumps.

Table 5 shows new wind power generation and hydro storage pumps with increased hydro power generation, which were investment options for consideration in this study. These are presented in Figure 3.

Table 5 Possible location and size of new wind and pumped hydro generation in Tasmania

<table>
<thead>
<tr>
<th>Generation type</th>
<th>Location</th>
<th>Possible connection point</th>
<th>Capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind power generation</td>
<td>North-West Tasmania</td>
<td>Smithton – a new 220 kV substation</td>
<td>Up to 1,000</td>
</tr>
<tr>
<td></td>
<td>NET (North-East)</td>
<td>Georgetown substation</td>
<td>30</td>
</tr>
<tr>
<td></td>
<td>Low-head wind farm</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>ST (Southern)</td>
<td>Waddamana substation</td>
<td>200</td>
</tr>
<tr>
<td></td>
<td>WCT (West Coast)</td>
<td>Farrell substation</td>
<td>100</td>
</tr>
<tr>
<td>Pumped hydro generation</td>
<td>Various locations within</td>
<td>Generation and pumps up to</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Tasmania</td>
<td>220 MW</td>
<td></td>
</tr>
</tbody>
</table>
Figure 3 Location of new wind generation and pumped hydro station

- Musselroe Wind Farm: 168 MW
- Woolnorth Studland Bay / Bluff Point: 140 MW
- Possible North West Tasmania wind farms up to 1000 MW
- Possible Low Head Wind Farm: 30 MW
- Possible pumped hydro up to 220 MW
- Possible Granville Harbour Wind Farm: 100 MW
- Possible Cattle Hill Wind Farm: 200 MW
2.1.3 Hydro-electric generation modelling

Tasmanian hydroelectric generation is modelled by means of individual hydroelectric generating systems linked to one of three common storages:

- Long-term storage.
- Medium-term storage.
- Run of river.

Table 6 identifies how individual generators are allocated across these storages and provides an indication of the storage energy available to the units.

Energy inflow data for each Tasmanian hydro water storage is determined from historical monthly yield information provided by Hydro Tasmania. In both the capacity outlook model and time-sequential model, AEMO used a scaled version of average monthly yield, extracted from records spanning 81 years, to deliver an annual inflow of 8,700 gigawatt hours (GWh).

<table>
<thead>
<tr>
<th>Storage type</th>
<th>Storage energy (GWh)</th>
<th>Stations</th>
</tr>
</thead>
<tbody>
<tr>
<td>Long-term</td>
<td>11,200</td>
<td>Gordon, Poatina.</td>
</tr>
<tr>
<td>Run of river</td>
<td>140</td>
<td>Meadowbank, Trevallyn, Wilmot, Cethana, Devils Gate, Reece, Tribute.</td>
</tr>
</tbody>
</table>

2.2 Market modelling methodology

2.2.1 Capacity outlook

AEMO’s generation outlook simulated the future generation mix by incorporating a least-cost expansion of large-scale generation of the NEM over a 20-year outlook period, from 2016–17 to 2035–36. The expansion plan aims to identify the least-cost mix of generation to ensure adequate supply to meet demand at the current NEM reliability standard. The outlook projects the generation mix by fuel type, location, and timing of investments and withdrawals.

The generation outlook provides a view of zonal generation required to meet forecast maximum demand and operational consumption. A unique generation outlook was required for each demand sensitivity and interconnector case modelled.

Over the projection period, the generation outlook optimised generation investments, withdrawals, and operational cost, taking into account requirements to:

- Dispatch generation to meet operational maximum demand plus minimum reserve level across each year.
- Ensure sufficient generation reserve is available to meet the reliability standard.
- Meet legislated and advanced policy objectives (Australia’s COP21 commitment, Large-scale Renewable Energy Target (LRET), and VRET).

Operational maximum demand requirements

Forecast maximum demand and minimum reserve levels determine the future generation and interconnector capacity required. Annual consumption and the demand profile affect the generation mix used to meet demand. This study uses AEMO’s 2016 NEFR to provide consumption and 10% probability of exceedance (POE) maximum demand forecasts for each NEM region, and assumes

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11 The reliability standard targets a maximum expected unserved energy of 0.002% of native consumption per region, in any financial year.


13 POE is the likelihood of a forecast being exceeded – a 10% POE forecast is expected to be exceeded, on average, only one year in 10.
minimum capacity reserves set to the size of the largest online generator, as a proxy for ensuring the reliability standard would be met and set.

**Generation requirements**

In determining the efficient generation mix required in the outlook, AEMO assumed all generators were offering to generate (bidding) at their short run marginal cost (SRMC). Each generator’s assumed SRMC was based on the information published on AEMO’s online NTNDP Database. This assumed perfect competition in the market, and generators being fully flexible to respond to market signals.

**Interconnector upgrade scenarios**

AEMO analysed a number of interconnector upgrade options including augmentation of interconnectors that link New South Wales with both Queensland and Victoria, new interconnection between Victoria and South Australia, and a second Bass Strait interconnector.

Dispatch differences between these options were modelled using alternative network constraints to reflect the differing network capabilities of the two alternatives in time-sequential modelling.

Preliminary modelling of all scenarios was conducted, allowing for incremental interconnector upgrade to gain understanding of the most likely timing of the link augmentation. This timing was subsequently locked down into the simulations.

**Legislated policy objectives**

A number of government legislated policies and commitments were modelled in the 2016 NTNDP, including the COP21 commitment, the LRET, and the VRET.

- The COP21 commitment requires a 26% to 28% reduction of national emissions by 2030 based on the 2005 emission level.
- The LRET is modelled using updated Large-scale Generation Certificate (LGC) inventories. The policy defines a target renewable generation level in 2020, with liabilities persisting up until 2030.
- The Victorian government is in the process of legislating the VRET, that incentivises at least 25% of generation from the region to be sourced from renewable technologies by 2020, and at least 40% by 2025. The developments incentivised by the policy to 2020 are expected to contribute to the LRET objective, while developments beyond 2020 are expected to have their LGCs voluntarily surrendered. Beyond 2020, therefore, the policy should contribute to a higher overall renewable penetration than the LRET requires (as is the case with existing Australian Capital Territory reverse auction outcomes). This advanced policy also requires an 80%–20% split between new wind and new solar technologies installed to meet the policy.

**2.2.2 Generation dispatch – time-sequential modelling**

The generation outlook aims to simulate efficient installation and retirement of generation and transmission investment. Some short-term operational issues, such as the hourly chronology of generation dispatch, transmission network congestion, and hydro-storage coordination, have not been taken into account. This necessitated running a time-sequential model to validate the plausibility of the capacity outlook model results.

A time-sequential model used the results of the capacity outlook model, and a forecast of network limitations, to simulate hour-by-hour generation dispatch across the NEM. This highlighted network congestion that may arise from retiring or building generation in a certain location, as well as other issues the capacity outlook model is not designed to capture.

The modelling followed an iterative process, whereby the generation outlook was changing to alleviate some of the network limitations that arose from retiring or building generation in particular locations.

The time-sequential model considered generator operational costs only in dispatching the market, as investment decisions were captured by the capacity outlook model. This simulated a perfectly

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competitive market using an SRMC bidding model, rather than a reflection of strategic bidding behaviours influenced by portfolio considerations.

In practice, offers from generators will be influenced by a number of real-world factors for the business owning the generator, including:

- Bids for other generators in the portfolio.
- The generator’s start-up times and costs.
- The generator’s flexibility to respond to signals.
- The retail load being supplied by the business.
- The business’ wholesale contract prices and position, and risk profile.

AEMO used a competitive bidding time-sequential model to simulate levels of inertia, dispatch, and fault levels on the network over the outlook period. The model provides an improved approximation of generation levels as compared to the SRMC model.

The time-sequential model incorporated the regulation currently in place to maintain the expected Rate of Change of Frequency (RoCoF) of the South Australian power system, in relation to the non-credible double circuit trip of the Heywood Interconnector, at or below 3 hertz per second (Hz/s). Flow limits on the Heywood Interconnector were based on the total inertia online in the South Australian region, to ensure the South Australian power system could continue operating after a double circuit outage of the Heywood Interconnector. In cases where an additional AC link between South Australia and either Victoria or New South Wales was built, the constraint limiting flow on the Heywood interconnector was revoked.

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3. GENERATION OUTLOOK

The next 20 years will be characterised by unprecedented transformation in the power industry as it transitions to a low carbon future. This is driven by three key factors:

- Legislated and advanced emissions reduction policy objectives (Australia’s COP21 commitment, LRET, and VRET).
- The reducing financial viability of ageing, emissions-intensive coal generation.
- Meeting forecast system operational consumption, characterised by relatively low growth as the penetration of distributed generation increases.

AEMO’s assessment has used market modelling, combined with generators’ public announcements of their intentions to withdraw at the end of expected plant lifetime (assumed to be 50 years), to assess a possible future generation mix under each scenario. Differences in the magnitude of the changing supply mix between the case studies of the three scenarios are detailed in this chapter.

3.1 Neutral scenario

3.1.1 Projected capacity mix – Base case

Over the 20-year modelled period, AEMO projects a decreasing market share for baseload coal generation, and an increasing penetration of intermittent renewable generation, as the market continues to evolve. Under the Neutral scenario’s Base case:

- 63% (15.5 gigawatts (GW)) of the existing coal generation fleet may retire by 2036.\(^{16}\)
- Up to 45.3 GW of new generation may be required by 2036, comprising wind (20%), large-scale photovoltaic (PV) (29%), gas-powered generation (GPG) (27%), and rooftop PV (25%).

Figure 4 shows the projected total installed generation capacity in the NEM, categorised by fuel type, for the next 20 years in the Base case. Emissions reduction incentives drive the projections of new installations. New installations are therefore mainly using intermittent renewable technologies, however additional firm capacity is also required to satisfy reliability requirements.

An increase in installed NEM capacity is forecast despite a relatively flat demand projection under the Neutral scenario, as a result of the increase in intermittent generation installations.

\(^{16}\) The Neutral scenario modelled the retirement of Hazelwood Power Station as a staged retirement between 2017–18 and 2020–21. This is different to the recently announced closure scheduled for March 2017.
Effects of the Victorian Renewable Energy Target

The advanced VRET policy aims to deliver 25% of total Victorian electricity generation from renewable technologies by 2020, and 40% by 2025. AEMO’s modelling suggests the policy will deliver about 4,800 MW of additional renewable generation to Victoria. It is understood that at least 20% of the new renewable generation will aim to use solar PV technologies.

The policy is forecast to influence NEM development, providing incentive for renewable generation proponents to locate in Victoria rather than other regions. For Tasmania, the VRET target may lower the value of the second Bass Strait Interconnector and defer substantial renewable generation build in the region until later in the period. Exporting local renewable generation from Tasmania to the mainland is more valuable if it displaces coal and gas generation rather than other renewable generation sources.

The figures below demonstrate the regional development of intermittent generation in the Neutral scenario’s Base case. The figures show that the southern regions are forecast to continue to dominate the renewable landscape in the next ten years, particularly as the VRET drives Victorian developments. In the longer term, New South Wales is forecast to increase its share of renewable generation. However, for Tasmania, the share of renewable generation remains relatively steady.
Figure 5 Projected total installed capacity of large scale intermittent renewable generation, by region (Neutral scenario – Base case)

Development in Tasmania – Base case
The specific development forecast for Tasmania is shown in Figure 6, and in the inset in Figure 5. Up to 730 MW of new wind capacity is projected to be installed in Tasmania over the next 20 years, even without the second Bass Strait interconnector. No large-scale solar PV capacity is expected to be installed, while up to 330 MW of rooftop PV is projected to connect in Tasmania, independent of the interconnector.

Figure 6 shows the installed capacity in Tasmania projected over the forecast period.
The 208 MW Tamar Valley Power station is assumed to remain mothballed under the Base case, with fixed operating and maintenance costs of approximately $2.1 million incurred each year. Given its mothballed status, its capacity is not included in the figure above.

### 3.1.2 Projected Tasmanian capacity mix in other case studies
Development of the proposed second Bass Strait interconnector is forecast to increase the financial viability of renewable generation in Tasmania, reducing the risk of being constrained off due to transmission limitations, and increasing access to the broader NEM. Tasmania’s relatively rich wind resources are more capable of export with a second link, while Tasmania’s ability to import electricity during off-peak periods increases the flexibility available to the Hydro Tasmania generation portfolio to maximise the value of stored water, and reduce NEM-wide system costs.

An additional South Australian interconnector reinforces South Australia’s ability to both export wind generation during periods of high production, and to import electricity when wind production is low. For Tasmania, the presence of another South Australian interconnector is projected to reduce Tasmania’s wind resource development in the next ten years. Given the anticipated timing differences of the two interconnectors (a South Australian link by 2021–22 and a Tasmanian link by 2025–26), Tasmanian developments would likely be impacted by South Australia’s first-mover advantage.

Development of both links will enable all of these projected benefits to be realised. While an early development of the South Australian link is forecast to lead to delayed development for Tasmanian wind farms (with more development in South Australia instead), long-term development is likely to be enhanced by the prospect that developers will seek increased diversity in their wind generation portfolios. The typical daily pattern for wind in Tasmania complements the profiles in other regions, helping to smooth the intermittency of wind generation in aggregate across the NEM.

Figure 7 below shows the existing and modelled development path for wind in Tasmania under each case study. Each case study assumes the same level of generation retirement across the 20-year planning horizon.
The figure demonstrates that:

- Between 600 MW and 1,200 MW of additional new wind capacity is forecast in Tasmania over the next 20 years.
- Without further interconnection, Tasmania can accommodate no more than 1,100 MW of wind farms before becoming constrained by transmission limitations.
- The second Bass Strait interconnector expansion is forecast to drive approximately 365 MW of additional wind capacity in Tasmania relative to the Base case with no transmission development, only approximately 60% of the increased export capability.
- The second Bass Strait interconnector case study delivers almost as much wind capacity in the long run as the ‘2BSI + 1200MW wind’ case study, which requires 1,200 MW of wind installed in time for the interconnector’s commissioning. This highlights that the timing of new Tasmanian renewable generation development need not coincide with the timing of the link to deliver market benefits.
- The timing and magnitude of wind build in Tasmania is influenced by the modelled earlier development of another South Australian interconnector.

Figure 7 Wind installation differences for Tasmania across each case study (Neutral scenario)

The above analysis highlights that wind generation from Tasmania will be relied on more over time as coal capacity progressively retires. As wind penetration increases in a particular region, there will be a diminishing return on further developments, as the correlation of generation in geographically near locations is relatively high. As such, increasing diversity of intermittent generator developments is expected to provide increased value to the generation mix, and a second Bass Strait interconnector can facilitate Tasmania’s increased contribution to that diverse supply mix.

3.1.3 Effect of interconnector options on NEM capacity mix

In addition to facilitating more renewable generation in Tasmania, a second Bass Strait interconnector would also provide benefit to the mainland by increasing the capacity for Tasmania to support Victoria during high demand periods. Arguably, with 600 MW of increased capability to export Tasmania’s excess hydro capacity, up to 600 MW of GPG developments could be deferred on the mainland.

Figure 8 and Figure 9 below show the GPG expansion for the NEM, for open cycle gas turbine (OCGT) and combined cycle gas turbine (CCGT) expansion respectively. The figures show that, for the cases with a second Bass Strait interconnector developed, there is some deferral of OCGT new build. In
particular, 600 MW is deferred in the 2030s in the second Bass Strait interconnector and ‘2BSI + 1200MW wind’ case studies, relative to the Base case. The case study with both the South Australian and Tasmanian interconnectors developed also delays 300 MW of peaking gas for several years in the 2030s.17

Figure 8 OCGT installed capacity differences for the NEM

Figure 9 below shows that to complement the benefits of deferring peaking investments, development of any additional interconnector is projected to reduce the need for CCGT developments by the study end. CCGTs are developed to not only provide capacity support at times of peak, but to typically operate at higher capacity factors, providing high volumes of energy to consumers, offsetting the reduction in coal generation.

Figure 9 CCGT development differences for the NEM for each case study

17 Due to end effects, care should be taken not to draw strong inferences from differences observed between cases in the last years of the study.
With increased interconnection, additional wind generation can be expected to provide the energy that CCGTs otherwise would need to provide. In the Neutral scenario, the additional interconnection with either Tasmania or South Australia does defer Victorian CCGT development by 2035–36. Any delays in the retirement of coal-fired generators would reduce the need for additional CCGTs and potentially reduce the benefits of greater interconnection.

3.2 45% Emissions Reduction scenario

3.2.1 Projected capacity mix – Base case

Under the 45% Emissions Reduction scenario, AEMO’s assessment projects total NEM installed capacity to increase by 71% to 2035–36 (as shown in Figure 10 below). Under this scenario, AEMO projects, by 2035–36, the retirement of 18.2 GW of coal plant and the installation of:

- 27.5 GW of large-scale renewable generation, comprising 14.8 GW of large-scale PV and 12.7 GW of wind.
- 11.7 GW of GPG.
- 12.0 GW of rooftop solar PV.
- 3.5 GW of battery storage.

Compared to the Neutral scenario, this scenario projects more coal-fired generation retirements and greater intermittent renewable generation development to meet the stronger carbon abatement target.

The 45% Emissions Reduction scenario includes the announced retirement of Hazelwood Power Station from 2017 and return to service of mothballed plant in South Australia, consistent with AEMO’s 2016 Electricity Statement of Opportunities (ESOO) update. The scenario demonstrates that with increased penetration of renewable capacity, and a reduced capacity of firm thermal capacity, the value of battery technology is increased. Battery ‘firms up’ renewable generation and allows energy shifting of wind and solar generation from periods of high operation to periods of low operation. This reduces fuel costs, and provides some support for grid reliability (subject to the capabilities of batteries and the duration of high demand events).

Alternatively, greater interconnection between regions may be beneficial (including greater interconnection to New South Wales), but this has not been tested.

Figure 11 below demonstrate the regional development of intermittent generation in this higher emissions reduction scenario’s Base case.

The figures show that the higher emissions reduction pathway incentivises a balanced development of renewable generation across NEM regions. For Tasmania, though, the share of renewable generation is expected to reduce relative to other regions.
The specific development forecast for Tasmania is shown in Figure 12 and the inset in Figure 11.

Up to 730 MW of new wind capacity is projected to be installed in Tasmania over the next 20 years, even without the second Bass Strait interconnector. This is equal to the Neutral scenario. Without increased interconnection to the mainland, Tasmania’s renewable sector is at risk of losing pace with the growth forecast for the rest of the NEM. No large-scale solar PV capacity is expected to be installed, while up to 330 MW of rooftop PV is projected to connect in Tasmania, independent of the interconnector.

Figure 12 shows the Tasmanian developments over the forecast period.
Figure 12 Projected total installed capacity in Tasmania by Fuel Type (45% Emissions Reduction scenario – Base case)

3.2.2 Projected Tasmanian capacity mix of other case studies

Figure 13 below shows the modelled development path for wind in Tasmania under each case study. Like in the Neutral scenario, the figure demonstrates that up to 1,200 MW of additional new wind capacity in Tasmania is forecast. This is despite the projected increased penetration of renewable capacity across the NEM in response to the transitional pressures of the higher emissions reduction target.

The case with both interconnectors augmented (to Tasmania and South Australia), shows delayed Tasmanian developments, with initial focus on South Australian developments, given the earlier interconnector commissioning. However, by 2035–36, the local Tasmanian generation developments are equivalent in the second Bass Strait interconnector and combined interconnector case studies.
Figure 13 Wind installation differences for Tasmania across each case study (45% Emissions Reduction scenario)

3.2.3 Effect of interconnector options on NEM capacity mix

Figure 14 and Figure 15 below show the GPG expansion for the NEM, for OCGT and CCGT expansion respectively. The figures show no discernible differences in the level of new GPG development projected between cases (although slight differences in the timing of new build are observed). With a capacity mix relying more on intermittent generation and battery storage, increased interconnection is projected to contribute less to supporting peak load conditions between regions and therefore not projected to defer any new peaking capacity installations. It is only with combined interconnection expansion that CCGT capital deferral benefits are forecast to be realised by 2035–36.

Figure 14 OCGT development differences for the NEM for each case study (45% Emissions Reduction scenario)
This scenario presents a strong development outlook for battery storage. However, the projected benefits of storage are largely independent of the interconnection developed, as shown in Figure 16 below.

Figure 16 Battery storage development differences for the NEM for each case study (45% Emissions Reduction scenario)

3.3 Low Grid Demand scenario

3.3.1 Projected capacity mix – Base case

Under the Low Grid Demand scenario, AEMO’s Base case assessment projects total NEM installed capacity to increase by 8.5 GW to 2025–26 and remain relatively steady to 2035–36 (as shown in Figure 17 below).
Under this scenario, AEMO projects, by 2035–36, the retirement of 18.8 GW of coal plant and the installation of:

- 13.4 GW of rooftop solar PV.
- 2.5 GW of large-scale solar PV.
- 4.7 GW of GPG.
- 5.8 GW of wind generation.

Figure 17 Total installed capacity by fuel type to 2035–36, Low Grid Demand scenario – Base case

The Low Grid Demand scenario projects that 3.3 GW additional coal plant may retire to 2035–36 compared to the Neutral scenario\textsuperscript{19}, due to the reducing financial viability of the coal plant. In this scenario, the entire brown coal generation fleet is retired in the next 20 years, as low grid demand leads to oversupply, which suppresses prices and creates volume risk.

The Low Grid Demand scenario includes strong penetration of rooftop PV, projected to reach 30% of installed capacity (17.4 Terawatt (TW)) by 2035–36.

The figures below demonstrate the regional development of intermittent generation in the Low Grid Demand scenario’s Base case. The figures show that the largest regions by load are forecast to dominate new renewable developments. The effect of the VRET is also clearly visible, with Victoria increasing its share of NEM-wide intermittent renewable generation capacity to 50%. For Tasmania, the share of renewable generation (excluding hydro) is expected to decrease as no new renewable generation is developed in the region.

\textsuperscript{19} The Low Grid Demand scenario modelled the retirement of Hazelwood Power Station as a staged retirement between 2017–18 and 2020–21. This is different to the recently announced closure scheduled for March 2017.
The specific development forecast for Tasmania is shown in Figure 19 and the inset to Figure 18. It shows that in this scenario, with high distributed generation, energy efficiency, and lower underlying growth, no additional renewable capacity is expected to be developed in Tasmania in the Base case, without the second Bass Strait interconnector. Further, with low demand growth and higher distributed generation, the scenario leads to retirement of the 178 MW Bell Bay Three Power Station and Tamar Valley OCGT plant. The 208 MW Tamar Valley Power Station is assumed to remain on stand-by, however, to provide back-up in the event that a fault on the Basslink interconnector leads to electrical islanding of Tasmania.

Up to 390 MW of rooftop PV is projected to connect in Tasmania, independent of the interconnector. Figure 19 shows projected Tasmanian developments over the forecast period.
3.3.2 Projected Tasmanian capacity mix of other case studies

For the Low Grid Demand scenario, the generation capacity forecast for Tasmania remains the same across all cases. Even the development of the second Bass Strait interconnector is projected to not attract more investment in the region. Any value provided by the interconnector, therefore, is isolated to increasing the value derived from the existing hydro facilities, rather than providing increased access to Tasmania’s additional renewable resources.

An additional South Australian interconnector is projected to reinforce South Australia’s ability to export wind generation during periods of high production and import electricity when wind production is low. However, as for Tasmania, South Australia’s development of new wind capacity is forecast to be much reduced, with only about 90 MW developed when the additional interconnector is installed.

In this scenario, the forecast effect of the VRET is even more dramatic. The VRET dominates renewable developments in this scenario, with approximately 5,000 MW of additional renewable (wind and large-scale solar PV) built in Victoria. As such, with limited operational demand growth, the policy effectively saturates the renewable energy market. A greater proportion of the LRET is met through renewable generation located in Victoria to meet both LRET and VRET, while not building any more capacity than necessary. There is also more projected LRET non-compliance in this scenario. The modelling also forecasts developers re-focusing on regions with low existing renewable penetration or where new capacity is needed to meet demand – behind the Victorian developments, both New South Wales and Queensland are also forecast to increase renewable capacity to meet the LRET.

Footnote: The proposed policy targets a percentage of generation in the region, not load.
As modelled in each scenario, the ‘2BSI + 1200MW wind’ case study delivers an additional 1,200 MW of wind in Tasmania by the commissioning date of the interconnector. This is in contrast to all other case studies, which do not develop additional wind capacity in Tasmania. This is shown in Figure 20 below.

**Figure 20 Wind installation differences for Tasmania across each case study (Low Grid Demand scenario)**

### 3.3.3 Effect of interconnector options on NEM capacity mix
Like the Neutral scenario, the development of the second Bass Strait interconnector does provide for reduced GPG development on the mainland. All cases involving the second Bass Strait interconnector serve to reduce the need for CCGT developments on the mainland, by improving use of existing resources in Tasmania. This is shown in Figure 21 and Figure 22 below.

**Figure 21 OCGT development differences for the NEM for each case study (Low Grid Demand scenario)**
Figure 22 CCGT development differences for the NEM for each case study (Low Grid Demand scenario)
4. MARKET BENEFIT ANALYSIS

This chapter presents AEMO’s assessment of the economic value of the interconnector options examined in each scenario case study. This analysis does not meet the requirements of a full RIT-T assessment, but provides a high level overview of the potential benefits that each interconnector may provide, focusing on the allowable market benefits in a RIT-T.21

The allowable market benefits included in this assessment include:

- Changes in fuel consumption arising through different patterns of generation dispatch and changes in network losses, including changes in variable operations and maintenance expenditure associated with dispatch. These are referred to as “Dispatch efficiency benefits” and have been calculated assuming perfect competition, with dispatch based on SRMC bidding.
- Changes in voluntary and involuntary load curtailment, referred to as “Reliability benefits”. These have been assessed at a high level only, as multiple Monte Carlo simulations were not performed.
- Changes in capital investment in non-transmission elements, referred to as “Capital investment efficiency benefits”, including savings associated with:
  - Differences in the timing of new plant.
  - Differences in capital cost.
  - Differences in fixed operational and maintenance costs.
- Changes in penalties paid or payable for not meeting the LRET, referred to as “Environmental scheme benefits”.

This report also refers to “resilience benefits”. These relate to benefits derived from increasing the power system’s resilience to low probability, high impact events such as interconnector failures. Resilience benefits are not a separate category of benefits, but a subset drawn from existing categories of RIT-T allowable market benefits. Potential resilience benefits are:

- For South Australia, the increased resilience to severe and widespread involuntary load shedding in the region following synchronous separation of South Australia from the rest of the NEM.
- For Tasmania, the increased resilience to generation dispatch inefficiencies throughout the NEM associated with a prolonged (yearlong) failure of the existing Basslink interconnector, weighted by the probability of such a prolonged outage occurring (assumed to be 5%).

In calculating resilience benefits for South Australia, a value of customer reliability (VCR) multiplier of 1.5 has been applied to quantify the cost of disruption, which includes a modest allowance for both direct and indirect economic impacts to reflect the severity of the outage.

The following potential benefits have not been included in this assessment:

- Competition benefits.
- Changes in ancillary service costs (with the exception of the dispatch efficiency benefits associated with revoking the RoCoF constraint in cases where there is additional South Australian interconnection).
- Changes in any additional option value not covered by the above definitions.

The net present value (NPV) of market benefits and costs has been calculated over 20 years to 2035–36 using a 7% social discount rate.22 The interconnector costs have been annualised to provide a NPV comparison of costs over the same time period, and are assumed to be competitively priced.

For market benefit analysis, network constraints have been included to capture operating costs under realistic network congestion.

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4.1 Neutral scenario

Table 7 below summarises the market benefits of the various interconnector upgrades and augmentations under the different Neutral scenario case studies.

Table 7 Market benefits of various interconnector options under the Neutral scenario – summary

<table>
<thead>
<tr>
<th>Case study</th>
<th>NPV of gross market benefits to 2035–36</th>
<th>NPV of annualised cost to 2035–36</th>
<th>Overall net benefit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base case</td>
<td>$170m</td>
<td>$47m</td>
<td>$123m</td>
</tr>
<tr>
<td>2BSI</td>
<td>$531m</td>
<td>$387m</td>
<td>$143m</td>
</tr>
<tr>
<td>2BSI + 1200MW wind</td>
<td>$377m</td>
<td>$387m</td>
<td>-$11m</td>
</tr>
<tr>
<td>New SA Link</td>
<td>$595m</td>
<td>$335m</td>
<td>$260m</td>
</tr>
<tr>
<td>New SA Link + 2BSI</td>
<td>$978m</td>
<td>$676m</td>
<td>$302m</td>
</tr>
</tbody>
</table>

The table above shows that all case studies, with the exception of the ‘2BSI + 1200MW wind’ case study, provide a projected positive net market benefit in the Neutral scenario. Given that AEMO’s assessment does not try to capture all potential market benefits, further assessments of each interconnector option are warranted.

4.1.1 Detailed benefit assessment of various interconnector options

While Table 7 above shows the overall net benefits, it does not detail the specific benefits provided by each interconnector development. Each interconnector development will vary in its ability to provide each ‘category’ of benefits, and it is useful to understand the difference between case studies. Table 8 provides a breakdown of market benefits in each category considered in this analysis.

Table 8 Market benefits of various interconnector options under the Neutral scenario – benefit detail

<table>
<thead>
<tr>
<th>Case study</th>
<th>Dispatch efficiency benefits</th>
<th>Reliability benefits</th>
<th>Capital investment efficiency benefits</th>
<th>Environ-mental scheme benefits</th>
<th>Resilience benefits</th>
<th>NPV of gross market benefits to 2035–36</th>
<th>NPV of annualised cost to 2035–36</th>
<th>Overall net market benefit</th>
<th>Incremental net market benefits</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base case</td>
<td>$117m</td>
<td>$27m</td>
<td>$31m</td>
<td>-$4m</td>
<td>$0m</td>
<td>$170m</td>
<td>$47m</td>
<td>$123m</td>
<td>$0m</td>
</tr>
<tr>
<td>2BSI</td>
<td>$202m</td>
<td>$114m</td>
<td>$165m</td>
<td>$2m</td>
<td>$48m</td>
<td>$531m</td>
<td>$387m</td>
<td>$143m</td>
<td>$20m</td>
</tr>
<tr>
<td>2BSI + 1200MW wind</td>
<td>$338m</td>
<td>$114m</td>
<td>-$136m</td>
<td>$11m</td>
<td>$50m</td>
<td>$377m</td>
<td>$387m</td>
<td>-$11m</td>
<td>-$134m</td>
</tr>
<tr>
<td>New SA Link</td>
<td>$324m</td>
<td>-$1m</td>
<td>-$6m</td>
<td>$117m</td>
<td>$161m</td>
<td>$595m</td>
<td>$335m</td>
<td>$260m</td>
<td>$136m</td>
</tr>
<tr>
<td>New SA Link + 2BSI</td>
<td>$451m</td>
<td>$85m</td>
<td>$111m</td>
<td>$123m</td>
<td>$209m</td>
<td>$978m</td>
<td>$676m</td>
<td>$302m</td>
<td>$179m</td>
</tr>
</tbody>
</table>

The benefits above include the inherent benefit in each case study of the interconnector upgrades assumed for the Base case, that is, the benefits provided by the QNI and VIC–NSW upgrades. The table also shows the incremental net market benefits, over and above the benefits attributable to the QNI and VIC–NSW interconnection augmentations.

Benefits of the second Bass Strait interconnector

As shown in Table 8, in the Neutral scenario the second Bass Strait interconnector is forecast to deliver:

- $85m in dispatch efficiency benefits.
- $87m in reliability benefits.
- $134m in capital investment efficiency benefits.
$6m in reduced environmental scheme costs.

$48m in improved Tasmanian resilience to the potential outage of the Basslink interconnector.

The largest of these projected benefits relates to the ability for the interconnector to delay or defer capital investment on the mainland, as discussed in Chapter 3. A new interconnector with South Australia cannot provide a similar benefit, given that South Australia’s generation mix is mainly intermittent, and therefore a new link would not ‘firm up’ that intermittent capacity to benefit the remaining NEM to the same extent.

This increased capacity to export firm hydro generation also provides additional projected reliability benefits, as the risk of voluntary and involuntary load curtailment is forecast to reduce in the cases where a new Tasmanian link is installed. The second Bass Strait interconnector reinforces connection between Tasmania and the mainland, reducing Tasmania’s exposure to extreme outcomes if that interconnector fails.

Increased resilience to potential failures of the Basslink interconnector is projected to provide further benefits. These benefits are not as significant as those provided by a new South Australian interconnector, as the risk of interconnector failure producing load shedding is low (so long as water storages are reasonable at the time of failure). Therefore, while dispatch efficiency would be significantly lower without the Basslink interconnector in service, the value of these costs is far lower than the value of reliability.

Benefits of the ‘2BSI + 1200MW wind’ case study

Building new renewable generation in Tasmania (1,200 MW of wind), timed to coincide with commissioning of the second interconnector, would not increase projected market benefits of the second Bass Strait interconnector.

Although this case delivers additional dispatch efficiency, environmental scheme, and resilience benefits, the additional capital investment costs outweigh the benefits gained. This is largely due to oversupply of renewable generation in the southern regions (South Australia, Victoria, and Tasmania).

Prior to the second Bass Strait interconnector, renewable generation is already built in South Australia (facilitated by LRET) and Victoria (facilitated by VRET and LRET). Without greater interconnection between Victoria and New South Wales, or further brown coal retirements, additional wind generation in Tasmania is projected to compete, at times, with other renewable generation on the mainland, and is therefore not as beneficial as it would otherwise have been in the absence of these other renewable energy policies.

Benefits of development of both interconnector options

Table 8 shows that the most beneficial development is forecast to be the combined development of the additional South Australian interconnector and the second Bass Strait interconnector. Developing both links, while the most costly option, requiring almost double the capital investment, is forecast to provide maximum dispatch efficiency benefits, environmental scheme benefits, and resilience benefits. It also produces large projected savings in reliability costs and capital costs.

As seen in Table 8, the projected value of developing both links is greater than the sum of its parts. That is, developing both links together is forecast to provide greater combined benefits than if each link was developed separately. This relates to further increases in dispatch efficiency associated with the increased diversity of renewable resources.

In a market where intermittent generation sources will provide a large volume of energy, the benefits of diversifying the intermittent resource become increasingly important.

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23 The levels of Hydro Tasmania storages at the time of any given Basslink outage, and the rainfall inflows during the period of outage, will impact the overall cost of any Basslink outage (as well as the timing and duration of any such outage). The 2015–16 Basslink coincided with low annual rainfall conditions, which presented additional challenges compared to the case if storages were higher. AEMO’s modelling for this assessment assumes ‘average’ rainfall inflows.
Generation diversity benefits

For any investment portfolio, it is prudent to 'hedge bets' and not be overexposed to any one solution. For share market investors, this will usually take the form of a diversified portfolio spanning many industries and sectors, including ‘blue chip’ defensive stocks and high dividend yield stocks, while also targeting areas of potential growth. By investing in this way, the underlying risk of the portfolio is reduced, while opportunity also exists to spread exposure to potential gains.

The same applies for the electricity sector – having a mix of geographically diverse technologies, particularly intermittent technologies such as wind and solar, will reduce investment risks associated with lack of resource availability in any one location, or for any one technology. It also lowers costs to consumers by smoothing the aggregate intermittency and reducing the need to dispatch higher marginal cost generation plant such as GPG.

Figure 23 below shows the average time of day generation from wind farms is available in different regions, based on historical data observed in 2013–14. The figure shows that the resource profiles of wind farms in South Australia and Tasmania are quite different – while Tasmanian wind has greater daytime production, South Australia’s wind generation profile has greater operation near peak load times in the evening and overnight. This will mean that, on average, South Australian wind generation will provide greater dispatch efficiency gains, as it is more likely that developing additional wind will offset higher-cost GPG. The Tasmanian wind resource, with increased availability during daylight hours, will be competing more with rooftop and large-scale solar PV and baseload thermal plant.

As rooftop PV installations increase and minimum demand starts to be observed during the middle of the day, this may lead to negative prices if inflexible baseload plant continue to operate at minimum loading. Therefore, additional wind from Tasmania could be of less value to the mainland than additional wind from South Australia, up to a point. Once good resource spots have been exploited, or too much wind is located in one geographic location, diversity in renewable resources will become more highly valued.

Figure 24 provides further clarity on the diversity of the wind resource across regions. The figure shows that Tasmania typically produces near its annual average during the winter months, when local demand is greatest, but also produces relatively high output during summer, the time where traditionally hot temperatures on the mainland drive high demand (and therefore when GPG production is most needed).

Even if South Australian wind were perceived to be better correlated with the operational demand curve, there is still inherent value in developing it from more locations. For every MW of wind in South Australia, there is a diminishing benefit of installing more capacity in that location, as that additional capacity will also compete with the existing wind.

The figures show that New South Wales wind patterns are also favourable when compared against peak demand periods. However, to build enough wind capacity to meet the region’s energy requirement, batteries would need to be installed, or export capacity would need to be further augmented, to avoid wind being constrained off due to network limitations at times of high production.

24 The 2013–14 year has been used as the reference year for all the modelling, from which demand, solar, and wind traces have been derived.
Improving use of existing Tasmanian Hydro

One of the projected effects of a second Bass Strait interconnector is an increased ability for Hydro Tasmania generation facilities with flexible storages to generate more during periods of highest value, and to import energy during periods of lowest value. From a market benefits perspective, increasing hydro production during periods of high GPG production would lead to increased dispatch efficiency benefits.

Figure 25 below shows the ‘duration curve’ of the hydro generation in Tasmania in 2024–25 and 2028–29 for all cases in the Neutral scenario. A duration curve represents the percentage of time hydro generation was at or above a given level. The figure shows that, without the development of the second Bass Strait interconnector (the Base case), the hydro portfolio is projected to operate more at low production levels, and less at high production levels.
The value of this peakier hydro generation utilisation can be observed by looking at average hydro generation by time of day. Figure 26 shows that the second Bass Strait interconnector is projected to allow Tasmanian hydro plant to generate more during morning and evening peaks, when prices are expected to be higher, and less during off-peak periods. The lower hydro capacity factor observed during daytime off-peak in the second Bass Strait case is due to the higher local wind generation assumed in this case (which typically generated more during off-peak periods in the 2013–14 reference year used in this study).
4.2 45% Emissions Reduction scenario

Table 9 below summarises the market benefits of the various interconnector upgrades and augmentations under the 45% Emissions Reduction scenario’s case studies.

Table 9 Market benefits of various interconnector options under the 45% Emissions Reduction scenario – summary

<table>
<thead>
<tr>
<th>Case study</th>
<th>NPV of gross market benefits to 2035–36</th>
<th>NPV of annualised cost to 2035–36</th>
<th>Overall net benefit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base case QNI VNI</td>
<td>$327m</td>
<td>$47m</td>
<td>$281m</td>
</tr>
<tr>
<td>2BSI</td>
<td>$611m</td>
<td>$387m</td>
<td>$224m</td>
</tr>
<tr>
<td>2BSI + 1200MW wind</td>
<td>$611m</td>
<td>$387m</td>
<td>$224m</td>
</tr>
<tr>
<td>New SA Link</td>
<td>$888m</td>
<td>$335m</td>
<td>$553m</td>
</tr>
<tr>
<td>New SA Link + 2BSI</td>
<td>$1,354m</td>
<td>$676m</td>
<td>$678m</td>
</tr>
</tbody>
</table>

The Base case in the 45% Emissions Reduction scenario is more beneficial than in either of the other scenarios. The stronger abatement target drives more black coal retirement in Queensland, increasing the value of the QNI augmentation to better use resources between Queensland and New South Wales.

4.2.1 Detailed benefit assessment of various interconnector options

The benefits of each case study are broken down by benefit category in Table 10 below.

Table 10 Market benefits of various interconnector options under the 45% Emissions Reduction Scenario – benefit detail

<table>
<thead>
<tr>
<th>Case study</th>
<th>Dispatch efficiency benefits</th>
<th>Reliability benefits</th>
<th>Capital investment efficiency benefits</th>
<th>Environmental scheme benefits</th>
<th>Resilience benefits</th>
<th>NPV of gross market benefits to 2035–36</th>
<th>NPV of annualised cost to 2035–36</th>
<th>Overall net market benefit</th>
<th>Incremental net market benefits</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base case QNI VNI</td>
<td>$99m</td>
<td>$187m</td>
<td>$45m</td>
<td>-$4m</td>
<td>$0m</td>
<td>$327m</td>
<td>$47m</td>
<td>$281m</td>
<td>$0m</td>
</tr>
<tr>
<td>2BSI</td>
<td>$251m</td>
<td>$335m</td>
<td>-$1m</td>
<td>-$1m</td>
<td>$27m</td>
<td>$611m</td>
<td>$387m</td>
<td>$224m</td>
<td>-$57m</td>
</tr>
<tr>
<td>2BSI + 1200MW wind</td>
<td>$251m</td>
<td>$335m</td>
<td>-$1m</td>
<td>-$1m</td>
<td>$27m</td>
<td>$611m</td>
<td>$387m</td>
<td>$224m</td>
<td>-$57m</td>
</tr>
<tr>
<td>New SA Link</td>
<td>$497m</td>
<td>$168m</td>
<td>-$8m</td>
<td>$70m</td>
<td>$161m</td>
<td>$888m</td>
<td>$335m</td>
<td>$553m</td>
<td>$272m</td>
</tr>
<tr>
<td>New SA Link + 2BSI</td>
<td>$686m</td>
<td>$295m</td>
<td>$114m</td>
<td>$72m</td>
<td>$188m</td>
<td>$1,354m</td>
<td>$676m</td>
<td>$678m</td>
<td>$397m</td>
</tr>
</tbody>
</table>

The benefits above include the inherent benefit in each case study of the interconnector upgrades assumed for the Base case. The table also shows the incremental net market benefits, over and above the benefits attributable to the QNI and VIC–NSW interconnection augmentations.

Benefits of the second Bass Strait interconnector

As shown in Table 10, in the 45% Emissions Reduction scenario the second Bass Strait interconnector is forecast to deliver:
- $152m in dispatch efficiency benefits.
- $148m in Reliability benefits.
• $46m greater capital investment costs.
• $3m lower environmental scheme costs.
• $27m in improved Tasmanian resilience to the potential outage of the Basslink interconnector.

The second Bass Strait interconnector provides more projected dispatch efficiency benefits in this scenario than any other. As coal-fired generation retires on the mainland, the improved utilisation of hydro generation and intermittent renewable generation attributed to greater interconnection reduces reliance on costly gas-fired generation.

Overall, however, the assessed net market benefit is negative. The interconnector provides projected benefits which are approximately $57m less than the interconnector development costs, due to a modest increase in capital investment efficiency and fewer resilience benefits. The higher build costs relate to the timing of renewable generation development, rather than fewer GPG capacity deferrals; the interconnector provides greater incentive to install wind capacity more quickly than the Base case, increasing build costs and therefore reducing capital investment efficiency benefits.

The resilience benefits are lower since the accelerated retirement of coal-fired generation means more GPG is required irrespective of whether Basslink is in service or not. The outage of Basslink simply means that more GPG is required in one region and less in the other. Additional detailed investigations should identify whether this shortage in benefits is recoverable through other cost categories, and whether alternative generation development plans (including new interconnection between Victoria and New South Wales) could produce a more positive result.

Benefits of the ‘2BSI + 1200MW wind’ case study
This scenario produces the same development pathway for the ‘2BSI + 1200MW wind’ case study as it does for the purer second Bass Strait interconnector case study. As such, there is no difference between outcomes between these two cases.

Benefits of development of both interconnector options
Table 10 shows that the most beneficial development is forecast to be the combined development of the additional South Australian interconnector as well as the second Bass Strait interconnector, as is also forecast for the Neutral scenario.

As in the Neutral scenario, the value of development of both links is greater than the sum of its parts. Interestingly, while both the second Bass Strait interconnector and additional SA interconnector cases forecast increased capital investments relative to the Base case, by developing both links the projection is for reduced capital investments. That is, while one link has not produced a forecast capital deferral benefit, developing both links does appear to deliver large capital investment efficiency benefits.

4.3 Low Grid Demand scenario
Table 11 below summarises the market benefits of the various interconnector upgrades and augmentations under the different Low Grid Demand scenario case studies.

Table 11 Market benefits of various interconnector options under the Low Grid Demand scenario – summary

<table>
<thead>
<tr>
<th>Case study</th>
<th>NPV of gross market benefits to 2035–36</th>
<th>NPV of annualised cost to 2035–36</th>
<th>Overall net benefit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base case QNI VNI</td>
<td>$163m</td>
<td>$77m</td>
<td>$86m</td>
</tr>
<tr>
<td>2BSI</td>
<td>$357m</td>
<td>$418m</td>
<td>-$61m</td>
</tr>
<tr>
<td>2BSI + 1200MW wind</td>
<td>-$269m</td>
<td>$418m</td>
<td>-$687m</td>
</tr>
<tr>
<td>New SA Link</td>
<td>$630m</td>
<td>$366m</td>
<td>$264m</td>
</tr>
<tr>
<td>New SA Link + 2BSI</td>
<td>$758m</td>
<td>$707m</td>
<td>$51m</td>
</tr>
</tbody>
</table>
The table above shows that the projected value of an additional Tasmanian interconnector is lower in this scenario. Any further investigations will need to consider the potential benefits of the interconnector under a range of possible futures, and as such the Taskforce should consider a diverse mix of scenarios in its next steps to ensure its conclusions are robust.

4.3.1 Detailed benefit assessment of various interconnector options

Table 12 below breaks down the source of benefits under the Low Grid Demand scenario for each interconnector development.

<table>
<thead>
<tr>
<th>Case study</th>
<th>Dispatch efficiency benefits</th>
<th>Reliability benefits</th>
<th>Capital investment efficiency benefits</th>
<th>Environmental scheme benefits</th>
<th>Resilience benefits</th>
<th>NPV of gross market benefits to 2035-36</th>
<th>NPV of annualised cost to 2035-36</th>
<th>Overall net market benefit</th>
<th>Incremental net market benefits</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base case QNI VNI</td>
<td>$111m</td>
<td>$58m</td>
<td>-$4m</td>
<td>-$2m</td>
<td>$0m</td>
<td>$163m</td>
<td>$77m</td>
<td>$86m</td>
<td>$0m</td>
</tr>
<tr>
<td>2BSI</td>
<td>$237m</td>
<td>$43m</td>
<td>$44m</td>
<td>-$3m</td>
<td>$36m</td>
<td>$357m</td>
<td>$418m</td>
<td>$61m</td>
<td>$-147m</td>
</tr>
<tr>
<td>2BSI + 1200MW wind</td>
<td>$858m</td>
<td>$43m</td>
<td>-$1,178m</td>
<td>-$3m</td>
<td>$11m</td>
<td>-$269m</td>
<td>$418m</td>
<td>$687m</td>
<td>$-773m</td>
</tr>
<tr>
<td>New SA Link</td>
<td>$416m</td>
<td>$38m</td>
<td>$19m</td>
<td>$6m</td>
<td>$150m</td>
<td>$630m</td>
<td>$366m</td>
<td>$264m</td>
<td>$178m</td>
</tr>
<tr>
<td>New SA Link + 2BSI</td>
<td>$438m</td>
<td>$93m</td>
<td>$44m</td>
<td>-$3m</td>
<td>$186m</td>
<td>$758m</td>
<td>$707m</td>
<td>$51m</td>
<td>$-35m</td>
</tr>
</tbody>
</table>

The benefits above include the inherent benefit in each case study of the interconnector upgrades assumed for the Base case, that is, the benefits provided by the QNI and VIC-NSW upgrades. The table also shows the benefits with the effects of those upgrades removed, that is, isolating the benefits of the interconnector augmentations themselves.

Benefits of the second Bass Strait interconnector

As shown in Table 12, in the Low Grid Demand scenario, the second Bass Strait interconnector is forecast to deliver:

- $126m in dispatch efficiency benefits.
- $15m in reduced reliability benefits (that is, higher reliability costs).
- $48m in capital investment efficiency benefits.
- No impact to environmental scheme costs.
- $36m in improved Tasmanian resilience to the potential outage of the Basslink interconnector.

Given the lower demand, the capital investment efficiency benefits of the interconnector are lower in this scenario than in the Neutral scenario. This was expected, given the analysis presented in Chapter 3. There are still some capital investment efficiency benefits, but these come at the expense of higher reliability costs, due to voluntary demand curtailment being relied on more often.

Dispatch efficiency benefits however, are higher than in the Neutral scenario as the interconnector facilitates better use of existing hydro generation. With more coal-fired generation retirements in this scenario, this improved use allows hydro generation to displace costly gas-fired generation.
The overall net market benefit of the interconnector is projected to be negative in this scenario, suggesting that the link would not provide economic value to consumers.

**Benefits of the ‘2BSI + 1200MW wind’ case study**

Building new renewable generation in Tasmania (1,200 MW of wind), timed to coincide with commissioning of the second interconnector, in a market which has a much reduced need for additional generation, would be highly inefficient. While the additional wind investment is projected to provide very large dispatch efficiencies, these forecast gains are eroded by the capital investment itself.

**Benefits of development of both interconnector options**

The increased benefit of a more diversified renewable generation portfolio with the development of both interconnectors is not as beneficial in this scenario. The generation mix is inherently more diversified in this scenario irrespective of the Tasmanian interconnector, with increased development of distributed generation across all regions, even though there is no new wind generation built in Tasmania. As such, while the link is projected to drive additional efficiencies, the cost of the link is forecast to outweigh the gains in market benefits attributed to the link.
5. TASMANIAN TRANSMISSION OUTLOOK

This chapter identifies potential limitations on the Tasmanian 220 kV transmission network, to accommodate increased new renewable generation in Tasmania and second Bass Strait interconnector using the scenarios outlined in Section 1.1.2.

This chapter also presents assessments on:
- Changes to network development on the mainland required to accommodate a second Bass Strait Interconnector.
- Emerging challenges to power system security and possible solutions.

5.1 Transmission limitations

Two types of limitations are considered in the transmission development outlook – reliability limitations and economic limitations:
- **Reliability limitations** occur if, at the time of regional maximum operational demand, the network does not have enough capacity to meet demand.
- **Economic limitations** are where more expensive generation is dispatched ahead of cheaper generation to avoid network overloads.

**Reliability limitations in the Tasmanian transmission network**

Since the Tasmanian demand forecast is almost flat in the Neutral and 45% Emissions Reduction scenarios, and reduced in the Low Grid Demand scenario, no reliability limitations were identified over the 20-year outlook period.

**Economic dispatch limitations in the Tasmanian transmission network**

Presently, there are number of constraints in Tasmanian transmission network at times of high generation from hydro generators or wind generators or increased import from Victoria. These are managed by generation re-dispatch and special protection schemes.

Connecting any more wind power generation is expected to increase network congestion, particularly at times of high wind power generation output. This may result in restricting wind and reducing efficient use of hydro generation.

This report identifies the location of potential economic dispatch limitations in the Tasmanian transmission network that may arise in all scenarios over the next 20 years, if new generation development occurs in line with the generation outlook in Chapter 3. These are listed in Table 13.

Most of these limitations already exist in the network. Those relating to wind generation are expected to become more prominent if more wind generation is connected in these zones.
Table 13 Potential economic dispatch limitations

<table>
<thead>
<tr>
<th>Potential transmission limitations</th>
<th>Dispatch conditions</th>
<th>Possible solutions</th>
<th>Scenarios</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transmission limitations on the Palmerston – Sheffield 220kV line</td>
<td>High wind generation in North-West Tasmania. High import from VIC to TAS through second Bass Strait interconnector</td>
<td>Reduce wind and/or hydro generation from North-West and West; Reduce import to Tasmania via second Bass Strait interconnector. Uprating of existing Sheffield–Palmerston 220 kV circuit for a higher thermal rating, or a second Sheffield–Palmerston 220 kV circuit.</td>
<td>Neutral and 45% Emissions Reduction. All case studies.</td>
</tr>
<tr>
<td>Transmission limitations on the Georgetown – Sheffield 220kV line</td>
<td>High wind generation from the North-West and West Tasmania area and, high Basslink export from TAS to VIC.</td>
<td>Reduce wind and/or hydro generation from North-West and West; Reduce Basslink export from TAS to VIC. Uprating of existing Georgetown – Sheffield 220 kV circuits for a higher thermal rating, or a third Georgetown–Sheffield 220 kV circuit.</td>
<td>Neutral, 45% Emissions Reduction. All case studies, except 2BSI and 2BSI + 1200MW wind studies.</td>
</tr>
<tr>
<td>Voltage collapse at Georgetown</td>
<td>High export from TAS to VIC at times of no GPG units in Tamar Valley and reduced number of hydro units in northern Tasmania (current issue to continue to future)</td>
<td>Reduce export from TAS to VIC; Constrain on generation in Tamar Valley and hydro units in northern Tasmania; Installation of additional reactive support at Georgetown substation.</td>
<td>All three scenarios. All case studies.</td>
</tr>
<tr>
<td>Transient over-voltage at Georgetown 220 kV</td>
<td>High export from TAS to VIC via Basslink at times of no GPG units in Tamar Valley and reduced number of hydro units in northern Tasmania (current issue to continue to future)</td>
<td>Reduce export from TAS to VIC; Constrain on generation in Tamar Valley and hydro units in northern Tasmania; Installation of additional dynamic reactive support at Georgetown substation.</td>
<td>All three scenarios. All case studies.</td>
</tr>
<tr>
<td>Basslink inverter commutation instability due to low fault level at George Town 220 kV</td>
<td>High import from Victoria to Tasmania via Basslink and low or no GPG units online in Tamar Valley and low or no hydro units in northern Tasmania (current constraint to continue).</td>
<td>Constrain on generation in Tamar Valley and hydro units in northern Tasmania; Operate existing GPG and hydro units as synchronous condensers. Installation of new synchronous condensers. Generation re-dispatch or constrain Basslink import into Tasmania.</td>
<td>All three scenarios. All case studies.</td>
</tr>
<tr>
<td>High rate of change of frequency (RoCoF)</td>
<td>High wind generation in Tasmania and/or increased import from Victoria to Tasmania and reduced Tasmania hydro units on line</td>
<td>Constrain on GPG and hydro units in Tasmania. Operate existing GPG and hydro units as synchronous condensers. Inertia support services from wind generation. Fast frequency services from non-network solutions.</td>
<td>Neutral and 45% Emissions Reduction. All case studies.</td>
</tr>
</tbody>
</table>

The timing and scope of any projects required to address potential economic dispatch limitations will depend on detailed market assessment of the costs and benefits of any solution.
5.2 Special Control Schemes in Tasmania

It is assumed the existing network control system protection scheme (NCSPS) and frequency control system protection scheme (FCSPS) continue to be available for service, and both of these system protection schemes would be extended to control the power flow on the second Bass Strait interconnector. HVDC based on VSC technology, which was modelled for the second Bass Strait interconnector, is capable of rapid control of transfer between ±600 MW between Victoria and Tasmania.

Low Grid Demand scenario assumptions include the retirement of a number of large industrial loads in the NEM, including in Tasmania. In this scenario, the lack of availability of large industrial load is projected to affect the existing FCSPS and lead to frequency control issues. To meet this projected challenge without a second Bass Strait interconnector, import from Victoria to Tasmania would need to be reduced.25 With the FCSPS not in service, a second Bass Strait interconnector could improve frequency control and allow increased imports from Victoria to Tasmania.

5.3 Network limitations in the mainland NEM

Compared to the Base case, the second Bass Strait interconnector case (including the ‘2BSI + 1200MW wind’ case study) is projected to defer the need for about 300 to 700 MW of new GPG in Victoria’s Latrobe Valley, but no other major generation changes are projected in the mainland.

In the Base case, the existing transmission lines in the Latrobe Valley area are projected to be sufficient to accommodate new GPG in the area. The reduction of 300 to 700 MW in Latrobe Valley GPG does not materially change projected transmission network augmentation requirements in the mainland NEM.

Retirement of coal-powered generation in the mainland would reduce available Frequency Control Ancillary Services (FCAS) in the NEM. However, there is adequate supply of FCAS for normal operating circumstances where FCAS can be sourced from anywhere within the NEM.26 The mainland is interconnected by alternating current (AC) network and existing hydro generators in New South Wales, Queensland, and Victoria, and Basslink could provide sufficient FCAS to the mainland. Other potential sources of FCAS could include GPG, a second Bass Strait interconnector, wind power generation, large-scale solar PV, and battery storage.

5.4 Emerging system security challenges

Increased wind power generation is likely to increase export to Victoria or reduce hydro generation in Tasmania. At times of low wholesale energy prices in Victoria or low water storage levels in Tasmania, Basslink and the second Bass Strait interconnector would facilitate high import from Victoria to Tasmania. Under such conditions, the number of hydro generators in service is likely to be reduced.

This may lead to power system security challenges such as reduced system inertia, less FCAS capability, and less system strength in the Tasmanian power system. As a consequence, frequency and voltage control is expected to become more challenging in Tasmania.

For all scenarios, possible solutions to address these power system security challenges include:

- A number of existing hydro generators and GPG in Tasmania could provide inertia services and system strength services by operating in synchronous condenser mode, but there are currently no market-based incentives for these services.
- There is a market mechanism to procure adequate FCAS capability through NEMDE (the NEM Dispatch Engine). This mechanism would result in re-dispatch of generators in Tasmania and Bass Strait interconnector transfer, to increase FCAS availability in Tasmania. The second Bass Strait interconnector was modelled with a VSC technology-based HVDC link, and this technology would

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25 This limitation has not been included in the market modelling, but given that it would only restrict imports into Tasmania, it is not expected to result in material differences in the analysis.
enable the second Bass Strait interconnector to provide better FCAS, compared to FCAS through Basslink

Retirement of coal generation in the mainland would reduce available FCAS in the NEM. As referred to in the 2016 NTNDP, sufficient sources of FCAS capability are projected on the mainland and through the existing Basslink interconnector, without the need for additional interconnection.
6. CONCLUSIONS

Based on the high level assessment undertaken for this report, a second Bass Strait interconnector may just provide sufficient market benefits under the Neutral scenario to justify the estimated $940 million investment, but the benefits are not robust. Under both the Low Grid Demand and 45% Emissions Reduction scenarios, the projected net market benefits of this investment are negative. Despite greater dispatch efficiency improvements in these two scenarios (driven by assumed accelerated retirement of coal-fired generation), the second Bass Strait interconnector was not projected to deliver net market benefits due to diminished capital deferral value.

Due to the sensitivity of this analysis to changes in market conditions, it is recommended that any further analysis on the benefits of Bass Strait interconnection include the following:

- Multiple reference years and Monte Carlo simulation modelling to better understand how sensitive the market benefits are to variations in renewable generation availability, coincidence of demand between regions, and thermal generation outages.
- Larger interconnector capacity options between Victoria and New South Wales.
- Consideration of competition benefits, and potentially wider economic benefits associated with improving Tasmania’s resilience to Basslink outages.
- Evaluation of economic limitations in Tasmania that may currently constrain renewable generation.
- Assessment of the transmission upgrades required in Victoria to accommodate high renewable generation penetration driven by the VRET.
- Additional scenarios to better understand the risks associated with this interconnector investment – potentially looking at more utility-scale battery and less gas-fired generation post 2030, or delayed coal retirements.

Under all scenarios, the earlier commissioning of a new interconnector between Victoria and South Australia is projected to improve the long-term market benefits associated with a second Bass Strait interconnector. As well, greater interconnection provided synergies that meant the combined net market benefits were likely to be greater than the sum of the separate effects. In particular, multiple new interconnections were able to exploit geographic diversity in wind availability and solar PV output to reduce the level of intermittency at an aggregate level across the NEM, lowering reliance on high marginal cost generation plant such as GPG to back up renewable generation.

This highlights the important of strategic, national, co-ordinated infrastructure planning to facilitate the transformation of the NEM at lowest cost to consumers.
# MEASURES AND ABBREVIATIONS

## Units of measure

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Unit of measure</th>
</tr>
</thead>
<tbody>
<tr>
<td>GW</td>
<td>Gigawatt</td>
</tr>
<tr>
<td>GWh</td>
<td>Gigawatt hour</td>
</tr>
<tr>
<td>kV</td>
<td>Kilovolt</td>
</tr>
<tr>
<td>MW</td>
<td>Megawatt</td>
</tr>
<tr>
<td>TW</td>
<td>Terawatt</td>
</tr>
</tbody>
</table>

## Abbreviations

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Expanded name</th>
</tr>
</thead>
<tbody>
<tr>
<td>AC</td>
<td>Alternating current</td>
</tr>
<tr>
<td>AEMC</td>
<td>Australian Energy Market Commission</td>
</tr>
<tr>
<td>AEMO</td>
<td>Australian Energy Market Operator</td>
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<tr>
<td>AER</td>
<td>Australian Energy Regulator</td>
</tr>
<tr>
<td>CCGT</td>
<td>Closed Cycle Gas Turbine</td>
</tr>
<tr>
<td>COP21</td>
<td>21st Conference of Parties, Paris</td>
</tr>
<tr>
<td>ESOO</td>
<td>Electricity Statement of Opportunities</td>
</tr>
<tr>
<td>FCAS</td>
<td>Frequency control ancillary services</td>
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<tr>
<td>FCSPS</td>
<td>Frequency control system protection scheme</td>
</tr>
<tr>
<td>GPG</td>
<td>Gas-powered generation</td>
</tr>
<tr>
<td>HVDC</td>
<td>High voltage direct current</td>
</tr>
<tr>
<td>LCC</td>
<td>Line-commutated current-sourced converter</td>
</tr>
<tr>
<td>LGC</td>
<td>Large-scale Generation Certificate</td>
</tr>
<tr>
<td>LRETP</td>
<td>Large-scale Renewable Energy Target</td>
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<tr>
<td>NCSPS</td>
<td>Network control system protection scheme</td>
</tr>
<tr>
<td>NEFR</td>
<td>National Electricity Forecasting Report</td>
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<tr>
<td>NEM</td>
<td>National Energy Market</td>
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<tr>
<td>NEMDE</td>
<td>NEM Dispatch Engine</td>
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<tr>
<td>NTNDP</td>
<td>National Transmission Network Development Plan</td>
</tr>
<tr>
<td>NPV</td>
<td>Net Present Value</td>
</tr>
<tr>
<td>OCGT</td>
<td>Open Cycle Gas Turbine</td>
</tr>
<tr>
<td>POE</td>
<td>Probability of Exceedance</td>
</tr>
<tr>
<td>PV</td>
<td>Photovoltaic</td>
</tr>
<tr>
<td>RIT-T</td>
<td>Regulatory investment test for transmission</td>
</tr>
<tr>
<td>ROCOF</td>
<td>Rate of change of frequency</td>
</tr>
<tr>
<td>SRMC</td>
<td>Short run marginal cost</td>
</tr>
<tr>
<td>VCR</td>
<td>Value of customer reliability</td>
</tr>
<tr>
<td>VRET</td>
<td>Victorian Renewable Energy Target</td>
</tr>
<tr>
<td>VSC</td>
<td>Voltage source converter</td>
</tr>
</tbody>
</table>
This document uses many terms that have meanings defined in the National Electricity Rules (NER). The NER meanings are adopted unless otherwise specified.

<table>
<thead>
<tr>
<th>Term</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>ancillary services</td>
<td>Services used by AEMO that are essential for:</td>
</tr>
<tr>
<td></td>
<td>• Managing power system security.</td>
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<tr>
<td></td>
<td>• Facilitating orderly trading.</td>
</tr>
<tr>
<td></td>
<td>• Ensuring electricity supplies are of an acceptable quality.</td>
</tr>
<tr>
<td></td>
<td>This includes services used to control frequency, voltage, network loading and system restart processes, which would not otherwise be voluntarily provided by market participants on the basis of energy prices alone.</td>
</tr>
<tr>
<td></td>
<td>Ancillary services may be obtained by AEMO through either market or non-market arrangements.</td>
</tr>
<tr>
<td>augmentation</td>
<td>The process of upgrading the capacity or service potential of a transmission (or a distribution) pipeline.</td>
</tr>
<tr>
<td>consumer</td>
<td>A person or organisation who engages in the activity of purchasing electricity supplied through a transmission or distribution system to a connection point.</td>
</tr>
<tr>
<td>customer</td>
<td>See consumer.</td>
</tr>
<tr>
<td>demand</td>
<td>See electricity demand.</td>
</tr>
<tr>
<td>demand-side participation</td>
<td>The situation where consumers vary their electricity consumption in response to a change in market conditions, such as the spot price.</td>
</tr>
<tr>
<td>energy</td>
<td>See electrical energy.</td>
</tr>
<tr>
<td>generating system</td>
<td>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.</td>
</tr>
<tr>
<td>generating unit</td>
<td>The actual generator of electricity and all the related equipment essential to its functioning as a single entity.</td>
</tr>
<tr>
<td>generation</td>
<td>The production of electrical power by converting another form of energy in a generating unit.</td>
</tr>
<tr>
<td>generation capacity</td>
<td>The amount (in megawatts (MW)) of electricity that a generating unit can produce under nominated conditions.</td>
</tr>
<tr>
<td></td>
<td>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.</td>
</tr>
<tr>
<td>generator</td>
<td>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 Rules) and, for the purposes of Chapter 5 (of the Rules), the term includes a person who is required to, or intends to register in that capacity.</td>
</tr>
<tr>
<td>inertia</td>
<td>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.</td>
</tr>
<tr>
<td>installed capacity</td>
<td>Refers to generating capacity (in megawatts (MW)) in the following context:</td>
</tr>
<tr>
<td></td>
<td>• A single generating unit.</td>
</tr>
<tr>
<td></td>
<td>• A number of generating units of a particular type or in a particular area.</td>
</tr>
<tr>
<td></td>
<td>• All of the generating units in a region.</td>
</tr>
<tr>
<td>interconnector</td>
<td>A transmission line or group of transmission lines that connects the transmission networks in adjacent regions.</td>
</tr>
<tr>
<td>interconnector flow</td>
<td>The quantity of electricity in MW being transmitted by an interconnector.</td>
</tr>
<tr>
<td>Large-scale Renewable Energy Target (LRET)</td>
<td>See national Renewable Energy Target scheme.</td>
</tr>
<tr>
<td>limitation (electricity)</td>
<td>Any limitation on the operation of the transmission system that will give rise to unserved energy (USE) or to generation re-dispatch costs.</td>
</tr>
<tr>
<td>load</td>
<td>A connection point or defined set of connection points at which electrical power is delivered to a person or to another networks or the amount of electrical power delivered at a defined instant at a connection pint, or aggregated over a defined set of connection points.</td>
</tr>
<tr>
<td>maximum demand</td>
<td>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.</td>
</tr>
<tr>
<td>Term</td>
<td>Definition</td>
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<tr>
<td><strong>National Electricity Law</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>National Electricity Market (NEM)</strong></td>
<td>The wholesale exchange of electricity operated by AEMO under the Rules.</td>
</tr>
<tr>
<td><strong>National Electricity Rules</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>National Transmission Network Development Plan (NTNDP)</strong></td>
<td>An annual report to be produced by AEMO that replaces the existing National Transmission Statement (NTS) from December 2010. Having a 20-year outlook, the NTNDP will identify transmission and generation development opportunities for a range of market development scenarios, consistent with addressing reliability needs and maximising net market benefits, while appropriately considering non-network options.</td>
</tr>
<tr>
<td><strong>National Transmission Planner</strong></td>
<td>AEMO acting in the performance of National Transmission Planner functions.</td>
</tr>
<tr>
<td><strong>National Transmission Planner (NTP) functions</strong></td>
<td>Functions described in section 49(2) of the National Electricity Law.</td>
</tr>
<tr>
<td><strong>net market benefit</strong></td>
<td>Refers to market benefits of an augmentation option minus the augmentation cost. The market benefit of an augmentation is defined in the regulatory investment test for transmission developed by the Australian Energy Regulator.</td>
</tr>
<tr>
<td><strong>network</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>network capability</strong></td>
<td>The capability of the network or part of the network to transfer electricity from one location to another.</td>
</tr>
<tr>
<td><strong>network congestion</strong></td>
<td>When a transmission network cannot accommodate the dispatch of the least-cost combination of available generation to meet demand.</td>
</tr>
<tr>
<td><strong>network constraint equation</strong></td>
<td>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’.</td>
</tr>
<tr>
<td><strong>network limit</strong></td>
<td>Defines the power system’s secure operating range. Network limits also take into account equipment/network element ratings.</td>
</tr>
<tr>
<td><strong>network limitation</strong></td>
<td>Network limitation describes network limits that cause frequently binding network constraint equations, and can represent major sources of network congestion. See also network congestion.</td>
</tr>
<tr>
<td><strong>network service</strong></td>
<td>Transmission service or distribution service associated with the conveyance, and controlling the conveyance, of electricity through the network.</td>
</tr>
<tr>
<td><strong>network service provider</strong></td>
<td>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 Rules).</td>
</tr>
<tr>
<td><strong>non-network option</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>power</strong></td>
<td>See ‘electrical power’.</td>
</tr>
<tr>
<td><strong>power station</strong></td>
<td>In relation to a generator, a facility in which any of that generator’s generating units are located.</td>
</tr>
<tr>
<td><strong>power system</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>power system reliability</strong></td>
<td>The ability of the power system to supply adequate power to satisfy customer demand, allowing for credible generation and transmission network contingencies.</td>
</tr>
<tr>
<td><strong>power system security</strong></td>
<td>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 Rules).</td>
</tr>
<tr>
<td><strong>reactive energy</strong></td>
<td>A measure, in varhour (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.</td>
</tr>
<tr>
<td>Term</td>
<td>Definition</td>
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<td>-------------------------------------------</td>
<td>-------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>reactive power</td>
<td>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.</td>
</tr>
<tr>
<td>region</td>
<td>An area determined by the AEMC in accordance with Chapter 2A (of the Rules), being an area served by a particular part of the transmission network containing one or more major load centres of generation centres or both.</td>
</tr>
<tr>
<td>regulatory investment test for transmission (RIT-T)</td>
<td>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.</td>
</tr>
<tr>
<td>reliability</td>
<td>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.</td>
</tr>
<tr>
<td>renewable energy target (RET)</td>
<td>See LRET and VRET.</td>
</tr>
<tr>
<td>rooftop photovoltaic (PV)</td>
<td>Includes both residential and commercial photovoltaic installations that are typically installed on consumers’ rooftops.</td>
</tr>
<tr>
<td>scenario</td>
<td>A consistent set of assumptions used to develop forecasts of demand, transmission, and supply.</td>
</tr>
<tr>
<td>security</td>
<td>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.</td>
</tr>
<tr>
<td>substation</td>
<td>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.</td>
</tr>
<tr>
<td>supply</td>
<td>The delivery of electricity.</td>
</tr>
<tr>
<td>synchronous condenser</td>
<td>Synchronous condensers are synchronous machines that are specially built to supply only reactive power. The rotating mass of synchronous condensers will contribute to the total inertia of the network from its stored kinetic energy.</td>
</tr>
<tr>
<td>transmission network</td>
<td>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 that is not referred to in paragraph (a) but is deemed by the Australian Energy Regulator (AER) to be part of the transmission network.</td>
</tr>
<tr>
<td>voltage instability</td>
<td>An inability to maintain voltage levels within a desired operating range. For example, in a 3-phase system, voltage instability can lead to all three phases dropping to unacceptable levels or even collapsing entirely.</td>
</tr>
</tbody>
</table>