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Benefits of Transmission Upgrades in a Transforming Electricity Sector

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Executive Summary

The electricity sector is undergoing a major transformation with the structure of the electricity market needing to evolve to allow for an optimal transformation. If ambitions to reduce emissions are realised a high level of low emission plant will be required to be installed in the period to 2030 to replace retiring coal plant.

The CEFC has commissioned Jacobs to provide insights into the potential role that interregional transmission could play in a transformed electricity sector. The insights were gleaned from three recent studies conducted by Jacobs, which had the aim of assessing the impacts of a range policies (under a range of targets) to reduce emissions. While the studies synthesised in the report were not intended to be a review of any specific interconnector, they do provide insights into the interconnector upgrades that would be required to efficiently meet various carbon constraints.

The studies had common features. First, they all examined scenarios where substantial emission reductions were required by 2030 ranging from 28% reduction to more than 45% reduction from current levels. Second, the studies examined a variety of policies to meet the target but under all policies there was a requirement to retire a high proportion of the existing coal fleet by 2030. Third, under most studies examined, interconnect upgrades played a material role in the transformed electricity sector.

The studies found that:

- For the emission targets examined, the entire brown coal fleet and some of the black coal fleet needed to be retired. In some scenarios examined, the entire brown coal fleet was retired by 2025.

- Retired coal plant were replaced with a mix of low emission plant, with the portion of new gas-fired and renewable energy required dependent on the policy deployed and underlying assumptions on emission reduction required, gas-prices, capital costs and demand growth. However, in most studies there was a high level of new renewable generation required, with deployment of new renewables required almost immediately after the policy is enacted (typically this was assumed to be 2020).

As far as interregional interconnection was concerned, the studies provided a number of insights into their potential role. The insights included:

- Large amounts of interconnection were required over the study period, with up to 3,500 MW of additional interregional capacity over the whole NEM by 2030.

- Given the range of emission reductions required and the immediate closure of coal fired plant explored under most scenarios, interregional transmission upgrades were required to allow exploitation of the available renewable resources (as well as gas-fired resources) to replace the coal fleet.

- The level and rate of retirement of the coal-fired capacity and particularly the brown coal fleet affected the level and timing of interconnect upgrades. Replacement of the coal capacity required a high level of entry of new low emission plant and the timeliness of this entry was facilitated by interconnect upgrades. Based on the assumptions used, interconnect upgrades facilitated the least cost level and location of new plant.

- The faster the rate of closure of coal capacity the sooner the interconnect upgrades were required. **Under most emission targets examined, a second link between Victoria and Tasmania was required by 2025**.

- The higher the level of renewable energy required the higher the level of interconnect upgrades and the sooner those upgrades occurred. In policies that targeted renewable forms of generation as the main source of emission abatement, interconnect upgrades were required to facilitate least cost development of the renewable energy either by allowing access to lower cost resources or by facilitating more efficient levels of dispatch of those resources.

- The level and timing of upgrades depended on assumptions of demand growth. Lower or higher rates of demand growth led to lower or higher levels of interconnect upgrades and the delay or bringing forward of upgrades. **But the need for and timing of some interconnect upgrade, such as a second interconnect across the Bass Strait, was only marginally affected, particularly to replace the brown coal fleet as retirement for these plant occurred around the same time in these sensitivities**.

Although the analysis points to the potential role of upgrades of interregional interconnect in facilitating the transformation of the sector, further analysis to confirm the benefits and costs will be required at a later stage.

1. Introduction

The electricity sector is undergoing a transformation. The drivers for this transformation include a move towards renewable generation, uptake of a greater diversity of supply sources and increasing levels of embedded generation. Going forward, uptake of additional renewable generation as part of the federal LRET scheme and perhaps as part of State based targets as well as moves to reduce emissions of greenhouse gases will see this transformation continue.

The structure of the electricity market will also need to evolve, including developments in network services. In this paper, we explore the role that interregional interconnects could play in the transformed market and the potential barriers to fulfilling this role.

The analysis draws upon the results of recent published studies which have examined the likely nature of the transformation in a carbon constrained world. The recent analysis will be used to provide some insights into the potential role of interconnection when there are large amounts of distributed low emission generation.

The analysis is not intended to be a full benefit-cost evaluation of the upgrades of interconnection. Rather it is to provide insights into the potential role of upgrades of interregional interconnect in facilitating the transformation of the sector.

2. Transformation of the electricity market

In this Section some of the trends leading to the transformation of the electricity sector are briefly discussed. The implications for transmission interconnections are also outlined.

2.1 Policy development

Australia has said it will ratify the Paris Agreement on Climate Change. Under that agreement Australia will commit to net zero emissions of greenhouse gases by 2050.

The Australian Government has promised to reduce emissions by 26% to 28% below 2005 levels by 2030. The Opposition promised in the last election to achieve a 45% reduction by 2030. For the electricity sector, these targets are shown in Table 1. The government target would see emissions falling from the current 187 Mt CO_2e to around 144 Mt CO_2e. This reduction of 43 Mt CO2e is equivalent to removing nine 600 MW black coal units from generation or removing the entire brown coal generation fleet with exception of Loy Yang B in the space of 13 years. Achieving a 45% reduction would see emissions reduce to around 108 Mt CO_2e or nearly 80 Mt CO_2e less than currently emitted.

Table 1: Targets assumed, Mt CO_2e

Item	Estimates
2005 Actual emissions	197
26-28% Target in 2030	144
45% Target in 2030	108
Emissions in 2030 to meet 2°C limit on temperature increase	60
2013 Emissions	187

Source: Analysis by Jacobs based on data provided by Department of the Environment (2015), *Australia's Emissions Projections: 2014/15*, Canberra (and previous issues).

The Federal Government has a number of initiatives to help achieve its target. For the electricity sector, the main initiative driving emission reductions is the Large-scale Renewable Energy Target Scheme. It is projected that meeting the target will require around 4,500 MW to 5,000 MW of additional renewable generation to be installed by 2020, with the bulk of this likely be shared between Victorian and New South Wales. Under the current interregional network configuration, additional uptake in Tasmania under the LRET is likely to be limited to around 500 MW[1], with low local demand and limited export capacity on the current link constraining any further increases. Without further upgrades of interconnection with the rest of the NEM, uptake in South Australia will also likely be limited by the impacts that additional wind generation will have on depressing South Australian regional prices at times of high power generation (affecting their profitability).

Several States are investigating targets for renewable generation. The ACT Government has a legislated target of 100% of the Territory's energy needs. The Victorian Government is assessing a target of 25% by 2020 (not additional to the LRET) and a 40% target by 2025. The Queensland Government is reviewing a target of 50% (of energy generation) by 2030.

If all the State schemes proceed, the total portion of renewable energy in the NEM in 2030 will be around one-third of total grid based generation in the NEM[2].

More stringent targets to reduce emissions of greenhouse gases would require even more low emission generation. A recent study conducted for the Climate Change Authority modelled a target that limits emissions so that global temperature rises are less than 2^{o} Celsius. In order to meet this target, emissions had to fall to around 60 Mt CO_2e by 2030.

2.2 Technological and social trends

A number of key trends are emerging within the NEM that will impact on the economics of interconnections.

The first trend is flat demand growth. AEMO's most recent projection has (grid-based) demand remaining flat for the period to 2035 but new loads may change the trajectory. There is also the prospect of major industrial loads closing their operations, particularly for aluminium smelting.

The stable demand has a number of implications for development of transmission interconnection. On the one hand, stable demand could mean there is no need to build new infrastructure, especially given the current over capacity in generation. But on the other hand, differences in interregional prices at times of high or low local wind power generation could create an incentive for interconnection to close the gap in prices. If large loads leave the market, there could also be a need for generators in the affected region to export generation from surplus capacity.

Technology development is also proceeding in somewhat uncertain direction and rate. The cost of large-scale solar PV generation has fallen dramatically to the point where this generation is becoming more competitive with other renewable alternatives. But wind generation technology has also developed and recent tender prices for wind generation has seen falls in the cost of wind, principally due to improved energy capture (leading to improved capacity factors). The latter development is opening more sites to the possibility of wind generation. However, different regions will have differing qualities in wind and solar energy resources and capturing lower cost resources may require transmission upgrades and radial extension of the existing network into new areas.

One development that may compete with interregional transmission development includes the developments of energy storage. With large scale adoption of storage, surplus energy within a region could be stored for later use rather than being exported to other regions.

However, in the case of Tasmania, with its large water storages, a new Bass Strait interconnect could enhance the usage of this notional storage capacity. Of particular advantage for Tasmania is that it provides the opportunity for inter-seasonal storage of surplus solar energy which is abundant in the summer time and much reduced in the southern states in winter[3]. The Tasmanian system receives hydro energy in winter and spring which it stores for use in summer and autumn when rainfall is more intermittent. Tasmania could receive surplus solar energy in autumn and summer from the mainland and conserve its hydro yield for export in winter and spring. Eventually the generation system could be further developed to increase the seasonal storage

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[1] This is determined by taking the deficit in demand (10,500 GWh after roof-top PV is deducted) and potential net export across the cable of around 1,200 GWh and deducting existing renewable generation in Tasmania (9,000 GWh long term average output for hydro and about 1,000 GWh for existing wind). New wind farm capacity required to meet this gap was determined by using a capacity factor of 38% for new wind farms.

[2] This does not include the contribution of embedded renewable generation such as roof-top PV.

[3] The typical winter day solar yield is about 40% of the average summer day yield as shown at Page 271 and 272 at http://arena.gov.au/files/2013/08/Chapter-10-Solar-Energy.pdf

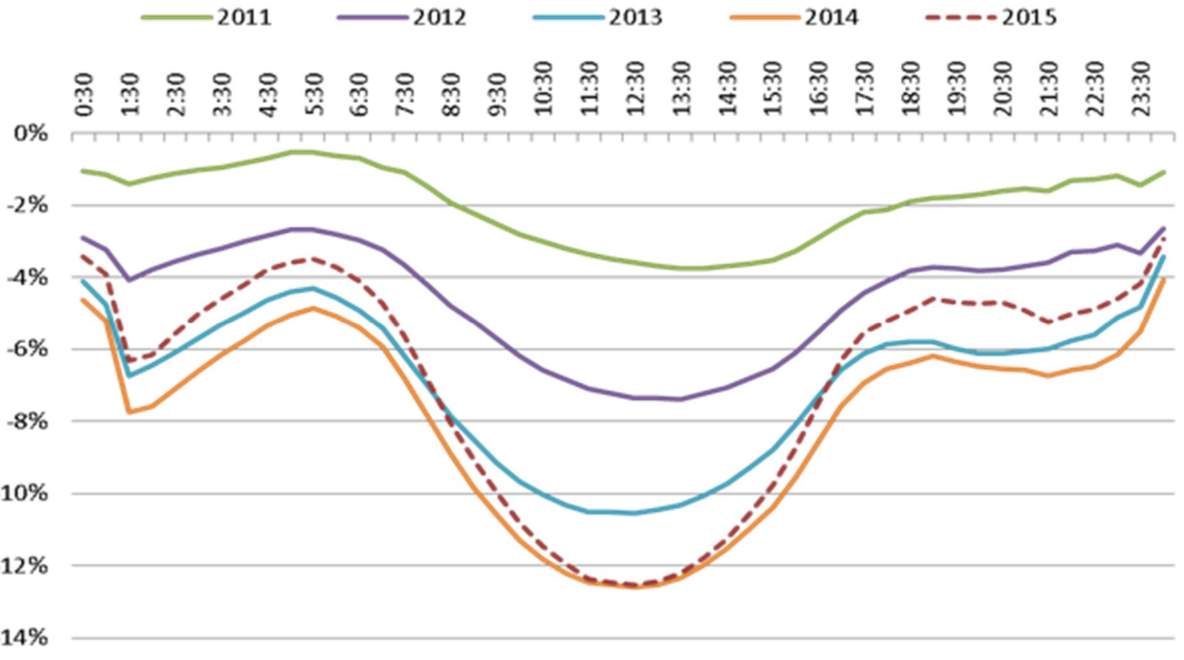
capacity to optimise such operations. A co-ordinated development plan would be needed to optimise the utilisation of the existing hydro system within the current capacity of Basslink, the subsequent development of a new Bass Strait interconnection, and then the further development of hydro-electric and wind resources in Tasmania to maximise the value of these assets. This plan would be realised through competitive market operations as well as regulated approval of transmission network developments.

Some commentators have argued that the role of major transmission systems could diminish in the future with the development of embedded generation and micro-grid. Certainly uptake of embedded generation, principally roof-top PV has continued with just over 5,000 MW of roof-top PV systems installed Australia wide, and around 4,500 MW in the NEM regions. Based on current trends, uptake is predicted to continue growing at around 600 MW, to reaching around 19 GW by 2035[4].

However, even with this uptake[5] a large amount of energy would still be supplied through the grid. Currently embedded generation accounts for around 10% of total capacity but it is projected to increase to over one-quarter of total installed capacity. Even with this degree of uptake, grid based demand is still projected to be high. It is worth noting that the flat demand projected by AEMO in its neutral scenario, has grid based demand at around or just above current levels even with the projected uptake rates for roof-top PV systems. For example, even with the installed capacity of embedded generation currently around 10%, the contribution to reducing grid based energy is still only around 3% of total energy demand.

The uptake of embedded generation may actually enhance the role of transmission interlinks. One impact already being felt is that the embedded generation is reducing daytime loads, leading to a shift to a later afternoon or early evening peak. In accordance with the overall decrease in demand over the period 2009 to 2015, an irregular decrease in average hourly demand has been observed over the years across the NEM. As shown in Figure 1 on an average hourly demand basis, demand has decreased by 7% overall, and by as much as 10% during the middle of the day. Average demand during peak afternoon period of 6:00 PM to 10:00 PM has decreased by less than 6%. The loss of the off-peak hot water heating load accelerated during the carbon pricing period of 2013 and 2014 which made the overall load profile less well matched to base load thermal power generation and has increased the value of energy storage and interregional power trading in off-peak periods.

Figure 1 Percent change in average hourly demand across the NEM, base year 2009



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[4] Jacobs (2016), *Projections of uptake of small-scale systems*, report to the Australian Energy Market Operator, June

[5] Achieving this level of uptake would mean that nearly 60% of residential premises would have installed systems.

The change in load profile will have different repercussions on the wholesale price of electricity, with price decreases in the middle of the day, when solar generation is occurring and leading to a shift in the peak price period to the evening. This price pattern may limit the uptake of solar PV unless sufficient large scale storage or more interconnection is developed to soak up the high levels of generation from solar PV during the middle of the day.

It is likely that a grid based system with transmission interlinks will be required even if the cost of electric battery energy storage falls rapidly, as such devices are not currently suited to energy storage over a yearly cycle.

2.3 Potential role for renewable generation

Analysing recent trends and developments as well as some of the insights from various modelling studies it is likely that renewable energy generation could play a more prominent role in the future. Some insights include:

- There is the potential for a growing role for renewable generation. Another 4,500 to 5,500 MW of capacity will be required to meet LRET target. Recent modelling has found that some 5,500 MW of new renewable generation will be required to meet the proposed Queensland 50% target[6], all to be developed next decade. And the Victorian target could require around 5,400 MW of additional renewable generation[7]. If all schemes proceed, some 16,000 MW of new renewable capacity will be required over the next decade.

  Even more will be required if the Government imposes policies to meet its emission targets. Based on work undertaken for the Energy Networks Association[8], without the two state based renewable targets, meeting the 28% target will require another 5,000 MW to 10,000 MW of new renewable generation with the actual amount depending on the structure of the abatement policy. An additional 22,000 MW to 25,000 MW would be required if the 45% target is adopted.

- There will be diversity in the location and type of renewable energy developed. Although the Victorian and Queensland targets will likely see more renewable generation in those States, meeting the LRET target could require generation to be more dispersed. However, the size of the requirement will likely mean that most of the generation will occur in the Eastern States. The location of this generation will be in part determined by regional export opportunities – if there is a limit in export capability then there will be a limit to the development of renewable generation in some regions in the near term. This limit is already becoming apparent in South Australia.

- Following on from the previous comment, over the longer term the amount of renewable energy in any region is limited by the ability to export any generation that is excess to local demand

- The recent AEMO demand forecasts now show the minimum regional wholesale demand in each region which is expected to eventually become negative in South Australia by 2035/36[9].

3. Potential benefits of a second interconnector

In this section, the potential benefits of a second interconnector adjoining the Tasmanian and Victorian regions of the NEM are discussed. The benefits of a second crossing of Bass Strait are derived from:

- The otherwise unrealisable potential of further development of wind and hydro-electric resources in Tasmania to support decarbonisation

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[6] See Queensland Renewable Energy Expert Panel (2016), *Credible pathways to a 50% renewable energy target for Queensland*, Draft Report, October (Figure 22, page 68)

[7] Victorian Department of Environment, Land and Water Planning (2016), Victorian Renewable Energy Auction Scheme: Consultation Paper, 2015, page 2

[8] Jacobs (2016), *Australia's Climate Policy Options: Modelling of Alternate Policy Scenarios*, report to the Energy Networks Association, August.

[9] Table 9 at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEFR/2016/2016-National-Electricity-Forecasting-Report-NEFR.pdf

- The spare generating capacity in the Tasmanian hydro-electric system that is in excess of peak demand in Tasmania plus the export capacity of Basslink which could be available to support the mainland at times of lower renewable generation.
- The high quality of Tasmania's underdeveloped renewable generation resources compared to the marginal resources on the mainland if thermal generation on the mainland is to be replaced.
- The diversity of renewable generation resources between Tasmania and the mainland.

We now discuss these benefits as they would be realised in the electricity market.

3.1 Benefits of interconnection

Potential benefits of a second interconnector across Bass Strait include:

- Allow the renewable energy resources of Tasmania to be developed. Currently the demand in Tasmania can largely be met by the local hydro-electric resources with hydro storage used to balance the mismatch between seasonal yield and the less seasonal energy demand. Available data indicate that current demand in Tasmania is around 10,500 GWh[10] compared to around 9,000 GWh[11] of hydro-electric generation (on a long term average basis) and 1,000 GWh[12] of large-scale wind generation. This leaves a deficit of 500 GWh of demand not met by the current renewable resources of the State[13]. This deficit combined with utilising the full export potential of the existing Basslink interconnector, there is room for another 1,850 GWh of new wind generation to be developed in Tasmania, which amounts to around 500 MW of new plant. The renewable energy resource is greater than this with the Jacobs database of renewable energy projects indicating around 56 MW of prospective biomass projects, 100 MW of potential upgrades to the existing hydro-electric plant and around 990 MW of known wind projects. The inferred resources are likely to be greater still[14].
- Lower market prices. The second interconnector would reduce prices in a region with low generation resources and bring prices across regions more aligned. Tasmanian prices generally track Victorian prices, but during periods of low inflow or when the import capacity is constrained, the prices could go above Victorian prices as local gas-fired generation is required. This potential benefit for a second interconnector is not likely to be high based on entrepreneurial energy trading due to close tracking of prices between Victoria and Tasmania when Basslink is unconstrained. This is apparent in Figure 2 which shows an early autumn week in 2015. Tasmanian price is significantly higher than the Victorian price when Basslink is constrained for import to Tasmania. However, increasing the transmission capacity across Bass Strait would remove this price difference and pass this economic benefit to Tasmanian power users (with lower prices) and Victorian generators (with higher prices).

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[10] Sourced from AEMO NEFR 2016 data. Equivalent to an underlying demand of 10,615 GWh minus rooftop PV production of 105 GWh.

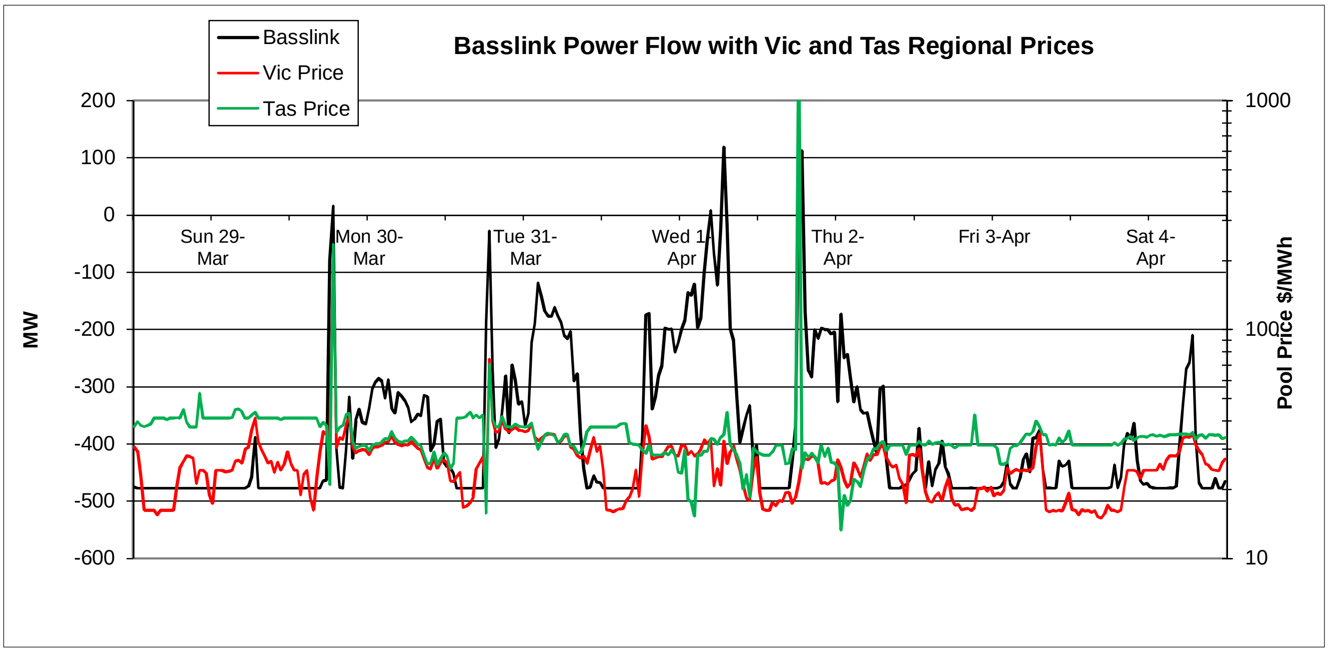
[11] Sourced from Tasmanian Energy Security Taskforce Consultation Paper, August 2016

[12] Sourced from Tasmanian Energy Security Taskforce Consultation Paper, August 2016

[13] This is currently met either by imports from through Basslink or from gas-fired generation located in Tasmania.

[14] A. Rothe, M. Moroni, M. Neyland and M. Wilnhammer (2015), "Current and potential use of forest biomass for energy in Tasmania", *Biomass and Bioenergy*, Volume 80. According to this article, the potential forestry biomass resource could supply up to 30% of Tasmania's energy needs.

Figure 2: Example of Basslink Trading and Interregional Price Difference



- Enhanced competition. Currently there is only one major generator in the Tasmanian region and when either Basslink is out or when imports are full, then prices in Tasmania could separate and Hydro Tasmania is then obligated to operate under external scrutiny due to its potential short-term market influence. When there is constrained supply, there is the potential for an incumbent generator to bid in higher prices through strategic bidding. Strategic bidding has been cited as a factor for exacerbating recent price spikes occurring in South Australia during the outage of the Heywood interconnector. Estimating the extent of this benefit is very difficult in a RIT–T cost benefit analysis, as any higher prices often occurs when unforeseen events constrains available supply and it is difficult to entangle strategic bidding from other economic or technical factors that may have led to higher bids. The potential for strategic bidding in Tasmania is currently limited by wholesale price regulation. However, there may be some benefit to enabling Hydro-Tasmania to operate in a more competitive environment without the potential inefficiency of less dynamic regulatory constraints such as price or bidding limits.

- Improves supply reliability. The second interconnect can cover for outages of Basslink and can provide more imported power during periods of prolonged low water inflow.

- For some regions, reduces ancillary service costs. This occurs because the second interconnector would reduce the number of times a region is isolated requiring more expensive local FCAS services. Until recently, Tasmania had the highest prices for regulation and contingency FCAS services.

- Diversity benefits. A second interconnector would minimises grid wide swings in intermittent generation by allowing increasing levels of wind generation in one region to cover for lower levels of wind generation in another region. This may be of limited benefit to Tasmania due to its extensive storage system and rapid response hydro-electric capacity. However, it could be of benefit to mainland intermittent generation for smoothing out generation on the mainland. This would also be useful between Victoria and NSW because these two regions often have different wind and weather patterns.

- Can improve security of supply by opening up new regions for generation. This is the greatest potential benefit of a second interconnector – this benefit is discussed in more detail in the following chapter.

- The opening of opportunities may be considered in terms of Western Victoria as a major 500 kV trading hub for gas fired and renewable energy on the basis that a second crossing from western Tasmania to western Victoria could have the following advantages:

  - Create a trading hub to optimise the use of wind power from South Australia, Western Victoria and Tasmania with peaking gas fired generation in western Victoria in support.
  - Be complementary to the possible addition of a second pole to Basslink to provide a balanced capacity between east and west Victoria and Tasmania.
  - Be complementary to further development of the interconnection between Victoria and South Australia and broaden the access for Tasmanian hydro storage to diverse generation resources across southern Australian mainland.
  - There is also the possible development of energy storage options in Victoria in the longer term which would supplement the seasonal energy storage in Tasmania.
  - Would provide ready access to a diversity of complimentary energy resources throughout South Australia and Victoria as the mainland interconnections are further developed.

3.2 Barriers to realising benefits

There is no doubt that the capacity of the current transmission systems will affect the optimal uptake (timing and location) of renewable energy technologies both under the LRET scheme or any subsequent carbon mitigation policy.

There are two main issues associated with renewable energy generation and transmission upgrades. Some transmission upgrades would assist in developing renewable energy projects in some regions but such upgrades could not be justified (or have high risks) because their economics depends on the renewable energy projects proceeding. There is the risk of stranded transmission assets if the renewable energy projects do not proceed[15]. Second, some benefits of transmission upgrades may not be easily captured or recognised in formal assessments under the assumption of a transforming electricity market. For example, transmission upgrades have an option value in allowing uptake of renewable energy in resource rich (but poorly networked) regions should circumstances require more renewable energy. There is also an insurance value for support during low probability but high impact events: witness the value that a second cable under Bass Strait would have had early this year given the prolonged outage of Basslink combined with low rainfall and low starting storage levels (the combination of these events has a very low probability but the impact of their concurrent occurrence on Tasmania’s electricity supply cost has been very high).

Upgrades of interconnections can also allow more competition by reducing the times that imports to a region are constrained (when imports are constrained is when generators in the constrained region can more successfully bid strategically to increase prices).

4. Insights from recent modelling

In this section, we provide insights from a number of recent studies into the potential need for and benefits of a second interconnector with Tasmania. The studies cited are:

- A study undertaken for the Climate Change Authority[16].
- A study for the Energy Networks Association[17].
- A study undertaken for The Climate Institute[18].

All studies had emissions targets at least equivalent to a cut in emissions of 28% by 2030 or more stringent. In the CCA study, emissions fell by 60% by 2030.

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[15] There is also the issue of network externalities associated with installing new networks to renewable rich areas.

[16] Jacobs (2016), *Modelling Illustrative Electricity Sector Emission Reduction Policies*, report to the Climate Change Authority, August

[17] Jacobs (2016), *Australia’s Climate Policy Options: Modelling of Alternate Policy Scenarios*, report to the Energy Networks Association, August

[18] Jacobs (2016), *Electricity Sector Impacts of Emission Abatement Policies*, report to The Climate Institute, April

4.1 Need for interconnection

In all studies, there was marked change in the generation mix by 2030:

- For the 28% target scenario in the ENA study, coal generation in the NEM fell from 155 TWh to 82 TWh to 100 TWh. Gas-fired generation increased from 20 TWh to 76 to 93 TWh in 2030 and renewable energy generation increased from 55 TWh to around 80 TWh. Brown coal generation in Victoria reduced by over half.

- For the 48% target scenario in the ENA study, coal generation fell from around 155 TWh in 2020 to 39 TWh to 54 TWh in 2030. Only one brown coal power station remained in operation by 2030. Although gas generation increased, renewable generation had the largest increase, going from 55 TWh in 2020 to 99 TWh to 120 TWh in 2030 requiring substantial increases in renewable energy resources across all regions.

- For the two degree scenarios in the CCA study, the entire brown coal fleet was retired by 2025 and the black coal fleet in the NEM was retired by 2031. For Victoria, this meant replacing over 55 TWh of brown coal generation with other forms of generation in less than 5 years. Although additional black coal and gas-fired generation played a role, the study found that renewable energy played a significant role in this replacement.

- Similarly in the TCI study, which examined mixes of policy approaches to reduce emissions, the brown coal generation in Victoria fell within a decade, with Yallourn closing before 2025 and Loy Yang A/B commencing closing before 2030 under the policy scenarios with a mixture of regulated closures of coal plant (by age), higher renewable targets or suboptimal carbon prices. Higher gas prices were assumed in this study than for the ENA studies and so more renewable generation was need to replace the brown coal generation.

None of the studies included modelling of the State based renewable energy targets but the level of renewable energy uptake was in line with the mooted targets for Victoria in almost all scenarios.

The studies found that significant interconnection upgrades were required. The extent of the upgrades was as follows:

- In the CCA study, the level of required upgrades ranged from 3,500 MW to around 7,000 MW with higher upgrades required for the higher the level of renewable generation. Around half of the upgrades were required by 2030, reflecting the severe reduction in coal fired generation in that period.

- In the ENA studies, only around 1,000 MW of upgrades were required in the period to 2030 for the 28% target. Around 1,750 MW of upgrades were required for the 45% target scenario.

- In the TCI studies around 2,200 MW of upgrades were required to the period to 2030 in the scenarios were there was a mix of policies to achieve the emission target.

The order of upgrades was consistent across the studies. In all studies examined, a doubling of the import /export capacity from Tasmania was required by 2025. Upgrades to the Queensland/NSW and the South Australia/Victoria interconnects were also required by 2030. The principle reasons for this were the low cost of the renewable resources in Tasmania and South Australia, and the exhaustion through development of the available low cost wind resources in Victoria in particular.

4.2 Conditions for interconnection upgrades

The modelling provided the following insights into the determinants of the upgrades:

- The level of and rate of retirement of the coal-fired generation and particularly the brown coal fleet. Replacement of the brown coal fleet required all the low emission sources of generation that could be obtained. And the faster the rate of closure the sooner the upgrades were required. In the 2^{o} Celsius target simulations for the CCA, the entire brown coal fleet had to be retired by 2025, which pushed the interconnect upgrades closer to 2020. Even for the 45% target simulation for the ENA the upgrade of the interconnection to Tasmania occurred around 2022. The lower 28% target still required the second interconnect by around 2025.

- The higher the level of renewable energy required the higher the level of interconnect upgrades and the sooner those upgrades occurred. In policies that targeted renewable forms of generation as the main source of emission abatement, interconnect upgrades were required to facilitate least cost development of the renewable energy either by allowing access to lower cost resources or by facilitating more efficient levels of dispatch of those resources.

- In the CCA study, sensitivities were performed to lower and higher rates of growth in demand. Clearly this lead to lower or higher levels of interconnect upgrades and the delay or bringing forward of upgrades. However, the need for and timing of the interconnect upgrade across the Bass Strait was only marginally affected, as the brown coal fleet still retired around the same time in these sensitivities.

4.3 Modelled benefits

From the modelling, it is difficult to estimate precisely the magnitude and range of benefits brought on by increased interconnection. But a review of the modelling results gleaned the following insights:

- Interconnect upgrades facilitated the rapid replacement of coal fired generation. In Victoria, with the requirement for rapid replacement of the brown coal fleet, the interconnect upgrades allowed more renewable energy resources to be developed in time to replace the brown coal fleet and also allowed the hydro-electric system to effectively provide peaking duty to the system in Victoria. In the case of the second interconnector from Tasmania, this was found by the modelling as lower cost than upgrades from other regions (due potentially to lower assumed cost, lower losses and higher capacity factor wind resources in Tasmania).

  For other interconnects, the upgrades allowed for a more optimal retirement of the black coal fired fleet (allowing lower cost black coal generation from Queensland to retire later than the black coal plant in NSW).

- Accessing resource rich renewable areas. Interconnection opened up resources in areas with limited access or limited need for additional renewable generation. Upgrades allowed for greater development of intermittent resources in Tasmania and South Australia.

- Under most assumptions used, even in cases with assumed lower costs for alternatives to interconnect such as battery storage systems, interconnect upgrades were still required as part of the least cost solution to supply electricity. This is because interconnect upgrades provides a greater range of benefits and because of the need for new interconnection early on in the next decade. In none of the alternative technology cases, did alternative options become cheaper in the early 2020s and hence the interconnect upgrades went ahead due to the need for the upgrades. In scenarios with high levels of intermittent renewable generation the level of interconnection (across regions with divergence in peak demand times and lower correlation of intermittent generation profiles) reduced the need for additional simple cycle gas turbines to provide backup to the intermittent generation.

- One of the key findings of the analysis was the rapid uptake of intermittent sources of generation, which led to high levels of generation at certain times of the day and even the potential for curtailed energy (if there was too much generation compared to local demand). Interconnect upgrades were essential in avoiding excessive curtailed energy.

- Similarly interconnect upgrades were often found to be economic to narrow potential price differences between regions and thereby replace higher cost generation with lower cost resources despite the additional power transfer loss across the interconnection.

In summary, in a world where greenhouse gas emissions are required to be reduced and the electricity sector is being transformed so that the existing coal fleet is being retired within 15 years, interconnect upgrades appear to be part of the least cost solution for replacement of the coal fleet with low emission plant. The second interconnector across Bass Strait appears consistently as one of the earlier upgrades required mainly to allow access to the mainland of lower cost wind generation in Tasmania, to avoid curtailing energy from intermittent forms of generation and to provide backup services to higher levels of intermittent generation in Victoria. This value is derived from the spare generation capacity in the Tasmanian hydro system that would be available to provide peaking energy to mainland in return for capturing the renewable generation at other times when there is a surplus to local load requirements in Tasmania or on the mainland.