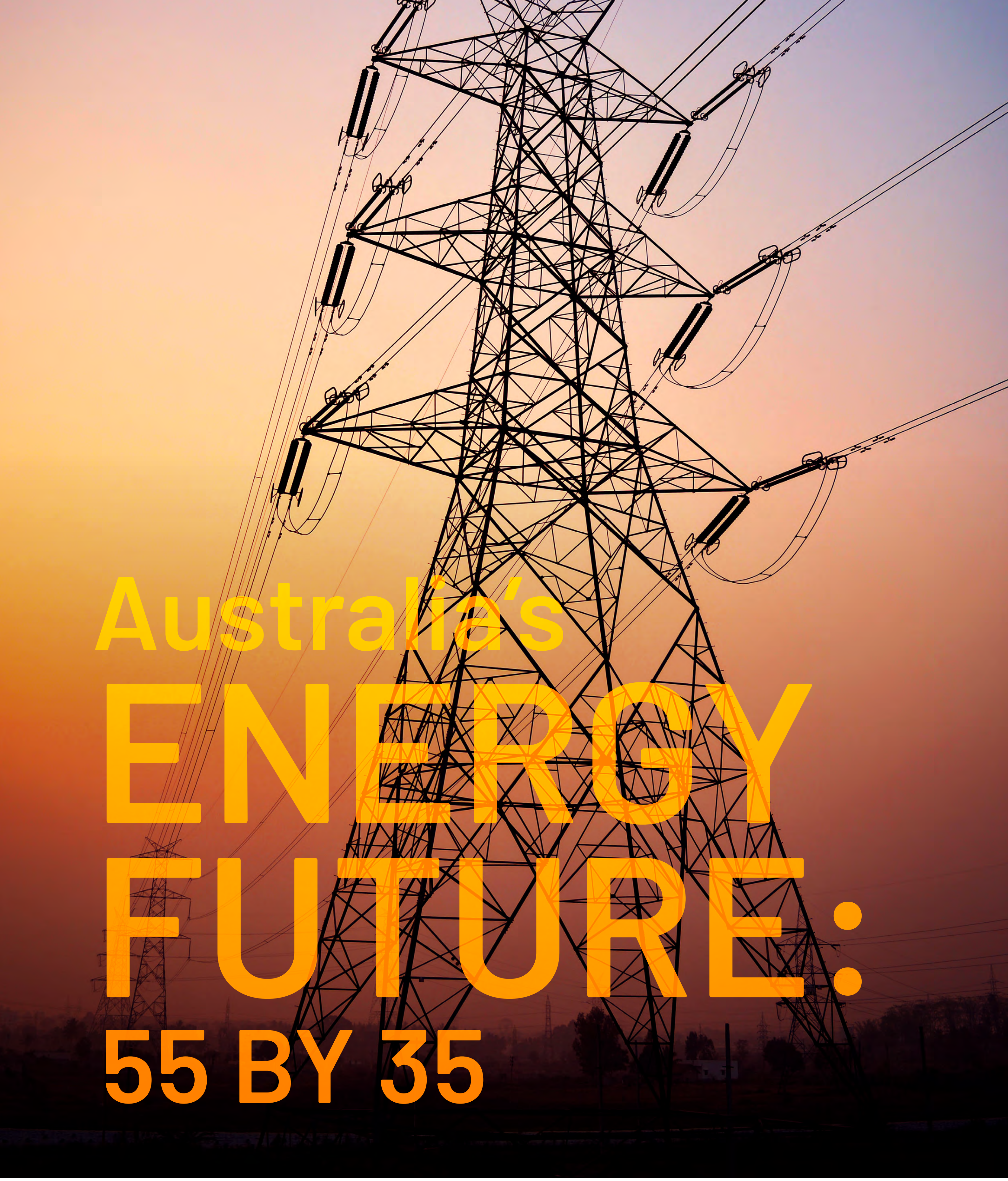

Australia's ENERGY FUTURE: 55 BY 35

Transmission Investment

AUSTRALIAN ENERGY COUNCIL

Executive Overview

The AEC has proposed an economy-wide interim emissions target of 55 per cent reduction on 2005 levels by 2035 as a milestone on the way to net zero. This paper is one in a series of papers exploring the implications of the 55 by 35 target. This paper looks at the implications of this target and the transition to net zero for Australia's electricity transmission networks.

It sets out the basic regulatory framework that applies to transmission in Australia and some of the consequences that arise from that approach, such as the need to have robust regulatory approval processes on behalf of consumers, given they are underwriting the investment.

The paper then focuses on building the transmission required to connect the large-scale renewable generators needed to progress Australia's transition to net-zero. That some new transmission is required is not in doubt.

But the continued support of consumers for the energy transition is predicated on building the system as efficiently as possible. This raises questions about how to determine what gets built and where, how it is funded and who should bear the risks of overbuilding or building in the wrong location.

> *That some new transmission is required is not in doubt. But the continued support of consumers for the energy transition is predicated on building the system as efficiently as possible.*

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Introduction

Electricity transmission systems are the high voltage wires that link large scale generators such as coal and gas plants, wind farms, and hydro systems to the low voltage distribution systems that bring electricity to homes and businesses (a few of the largest users are directly connected to the transmission network). Australia has two main transmission networks: the National Energy Market (NEM) that covers eastern and southern states and the Southwest Integrated System (SWIS) that covers Perth and the south-western corner of Western Australia. While the SWIS has a single transmission network service provider (TNSP) in the form of state-owned Western Power, the NEM has five large TNSPs, one for each state covered by the NEM and three smaller TNSPs who operate interconnectors (transmission systems connecting two states). In the NEM, the market operator AEMO has an important role to play in national planning and is also the state planner for Victoria.

The electricity transition that started over a decade ago, and will continue as Australia progresses towards net zero emissions, has major implications for the transmission networks. The best sites for new generation sources like wind and solar are not necessarily where the existing transmission lines run to the grid, as they were largely built to connect areas rich in coal deposits with major load centres. The different generation patterns of renewables also change the economics of strengthening the connections between states (since electricity grids were initially state-based, interstate links are relatively weak). So, the case for some new transmission lines is very strong. The fundamental question is how to build for the transition efficiently. This raises questions over how decisions are made about individual projects, how they fit together, managing bottlenecks if multiple projects proceed simultaneously, who pays for them and who bears the risk of mistakes. It also raises questions about the trade-off between generation and transmission, including determining the efficient level of congestion or constraint on the system. This latter issue is especially hard to resolve given the fundamental differences in how transmission and generation are rewarded (with transmission being a regulated revenue stream while generation revenue is determined by the market).

This paper works through these issues and sets out the current state of play, including the role of different levels of government.

The role of transmission

Transmission is the transport of electrons at high voltage from large-scale generators to major load centres. Transmission networks connect to distribution networks, where electricity can be stepped down to lower voltage and to a handful of the very largest users, for example aluminium smelters. Physically, they consist of the towers and wires that carry electricity, as well as substations, transformers, switching equipment, and monitoring and signalling equipment. The primary activities of transmission networks are thus:

- Network planning – determining the future needs of the network and how to meet those needs (new investment and/or network support contracts). In the NEM, AEMO is the national planner, and the jurisdictional planner for Victoria, but elsewhere, the regional TNSP plans its own network.
- Network operations – keeping the network operating safely and securely on a day-to-day basis. In the NEM, transmission networks have responsibility for procuring certain system services.
- Network maintenance – fixing the network when things go wrong – generally either due to failure of old assets or weather events.
- Connections – ensuring new generators can connect to the network.

Transmission networks are a natural monopoly – it is not efficient to have duplicate networks that customers can choose between. Consequently, they are subject to economic regulation; by the Australian Energy Regulator (AER) in the NEM and the Economic Regulation Authority (ERA) in Western Australia. The regulatory framework results in a set of incentives on transmission operators that lead to high levels of risk-aversion ensuring they will not begin to build a new project until they have confirmed that they can recover their costs in full.

Transmission costs are ultimately paid for by customers. Generators only pay to connect to the shared network. The regulatory framework seeks to protect consumers from excessive costs by having a rigorous process for approving new transmission projects.

The transmission network is open access but because generators are not paying for the shared network, they are not assigned any firm rights. When multiple generators are generating at the same time, their available output may be higher than the transfer capacity of the network. Generators may be constrained from delivering their maximum output, and this is called congestion. Some congestion is likely to be efficient.

Co-ordinating generation and transmission

While transmission is a regulated monopoly, generation is a competitive market and investment in generation is supported by investors' assessments of market revenues over time, rather than a guaranteed return for the life of the asset. This creates challenges for system planning, especially in situations where the network is being extended to allow new generation to connect.

Risk allocation options

While the standard approach in Australia is that transmission is provided as a regulated service, this is not the only option. The table below sets out the three primary options for driving investment in transmission: generator underwriting, TNSP self-underwriting or customer-underwriting. Each allocates the risks of whether a good investment decision has been made differently, and so the benefits of the investment also flow differently.

The model can be applied in different contexts – for example, a TNSP speculation approach to interconnectors is one where the TNSP makes money on the price arbitrage between the two regions it is connecting (or by selling this right to some other party).

Policy and regulatory issues

Transmission networks are natural monopolies and accordingly are heavily regulated. The risks associated with investing in new transmission should lie with the party best able to manage them.

The key issue is that different parties disagree where risks should lie. The current framework imposes most of the risks of overbuilding, inefficient costs or excess congestion on consumers, even though they are not best placed to manage the relevant risks. However, they are the beneficiaries of an optimised transmission network that minimises the combined cost of generation and transmission whilst meeting reliability standards.

The main activity of the networks – operating, maintaining and, where necessary, augmenting – the shared network is subject to a revenue cap that is set every five years. Because their revenue is fixed, the network businesses have a strong incentive to keep their costs down, although the rules require them to return a portion of any savings to customers through lower future prices. A set of standards (with penalties for non-compliance) and other incentives act as a safeguard against cost-cutting to the point that the quality of service degrades.

This basic framework is known as incentive-based regulation and is widely used in the UK (where the framework was developed), Europe as well as Australia and New Zealand. By contrast, most US networks are subject to a simpler form of regulation called cost-of-service.

The process, or determination, of setting the allowed revenue takes approximately two years from start to finish, hence why it is set for a five-year period. Given the

Table 1 *Risk allocation options*

	GENERATOR CO-ORDINATION	TNSP SPECULATION	REGULATED SERVICE
Description	Generators connecting in the same area coordinate connections	Generators connecting in the same area coordinate connections	Generators connecting in the same area coordinate connections
Who pays	Generators pay to connect	TNSPs - but if generators connect in the future, costs would be recovered from consumers or generators (depending on the model)	Consumers - so this model requires regulatory sign-off
Who bears the risk	Generators – if not enough of them connect	TNSPs – until sufficient generators connect	Consumers - including facing the stranded asset risk
What's in it for them	Generators can acquire firm access rights	TNSPs may be able to make greater profits than under a regulated model	Consumers may get lower wholesale prices because new generation is encouraged to connect

process is about trying to predict the future costs of the business there are risks in extending the period out longer. Until recently, the final determination could be appealed, but that right has now been removed. Importantly, given the need for additional transmission to support the energy transition, there are separate processes for large projects, so that the TNSP does not have to wait until the next five-year period to see if it can get these projects funded. These include a test to determine if a large project is worthwhile and the best option to solve the identified need, and a process for the regulator to review a robust estimate of the costs and determine an additional revenue allowance if required.

Capital expenditure is added to the Regulatory Asset Base (RAB). Once in the RAB, it can earn a return of capital (depreciation, typically over 50-60 years for a major project) and a return on capital (to cover a blend of debt and equity financing for the expenditure). This guaranteed return helps the TNSP to obtain finance for its capital expenditure.

The unusually high level of capital investment required for the transition is challenging this underlying assumption of financeability. Transgrid, the NSW TNSP, is particularly impacted as NSW's position in the middle of the NEM means that most projects to strengthen the overall system pass through NSW. If all the relevant projects in the ISP went ahead in the timeframes suggested by AEMO, Transgrid would double its RAB in under a decade. Transgrid has already argued that it needs more flexibility than the rules currently allow to finance its share of Project EnergyConnect, the NSW-South Australia interconnector. The AEMC did not accept its arguments, and Transgrid eventually secured financing from the Clean Energy Finance Corporation (CEFC), the Federal Government's "green bank". The CEFC has a broader transmission funding program available for other projects.

The AEMC is now proposing to give more flexibility to the AER to vary the depreciation profile on ISP projects to make them easier to finance. As a consequence of this accountability, customers will pay more for these projects in the short term, although they should pay the same in real terms over the life of the asset. The AEMC is also considering making more projects contestable. This could allow for projects to be spread across a wider set of TNSPs, which could make financing easier.

The Queensland and Tasmanian TNSPs are owned by their state governments, so these financing issues are likely to be less relevant (so too for Western Australia, which is subject to a similar framework but one overseen by the ERA and the State Government rather than AEMC/AER). Additionally, the new Federal Government's $20bn Rewiring the Nation plan may render these issues redundant, although the details of implementing this plan are yet to be released.

Regulatory tests

Regulatory tests are processes to determine whether certain types of network investment should go ahead and be paid for by consumers. The network proponent identifies a need and models the costs and benefits of a range of options (including non-network options). It releases its analysis for consultation amongst its stakeholders and uses this feedback to finalise its analysis and determine the option with the maximum net benefits, which it then submits to the regulator for review and approval.

The key elements that the test must incorporate include:

- The use of cost-benefit analysis against a counterfactual of the status quo (i.e., where none of the options take place) and the use of standard discounting techniques to obtain a net present value of each of the options.
- The use of sensitivity analysis to check how the results are affected by changing or relaxing some of the underlying assumptions.
- Defining the kinds of benefits that can be taken into account in carrying out the analysis.
- Consideration of all credible options for addressing the specified need, which include any relevant non-network options (such as generation, demand management or network support agreements).

The network must subsequently make a separate application to the regulator with a more detailed project costing in order for the costs to be added to the network's RAB.

In the NEM a transmission business must carry out a regulatory test (known as a regulatory investment test for transmission or a RIT-T) if it wants to build new network infrastructure to reduce congestion (as opposed to maintaining reliability, which is the other major driver of new investment) within their own region or between their region and another region. The test to planned infrastructure that would cost over $6m, with exemptions for certain urgently required investment. In Victoria, AEMO has the transmission planner role, so it carries out the RIT-T.

Most criticism of the RIT-T process falls into one of three categories:

- It takes too long;
- It doesn't account for all the potential benefits; and/or
- TNSPs may not be incentivised to choose the right option - in particular, non-network options rarely get due consideration.

These criticisms are briefly considered below.

It takes too long

A RIT-T can take up to five years including approval of the final budget by the AER. Then it must be built. There are concerns that this will unduly slow the transition or delay benefits to consumers. These concerns are mounted with the publication of the ISP which appears to have worked out which projects are worthwhile already. However, the ISP is a whole of system plan. It is not unreasonable for individual projects to have to stand on their merits, especially given there have been cost estimate increases of over 100 percent between ISP and the final stage of the RIT-T for some recent projects (it is not unusual for project costs to rise as the project becomes more highly specified). The purpose of the RIT-T process is to protect customers from paying over the odds for infrastructure, as they bear the risks of a transmission project not delivering the expected benefits. Other routes are available to build transmission that lead to other parties bearing these risks, and such routes do not have to satisfy the RIT-T, so can proceed more quickly. A case study of the largest RIT-T to date, the South Australia-NSW interconnector, can be found in Appendix 2.

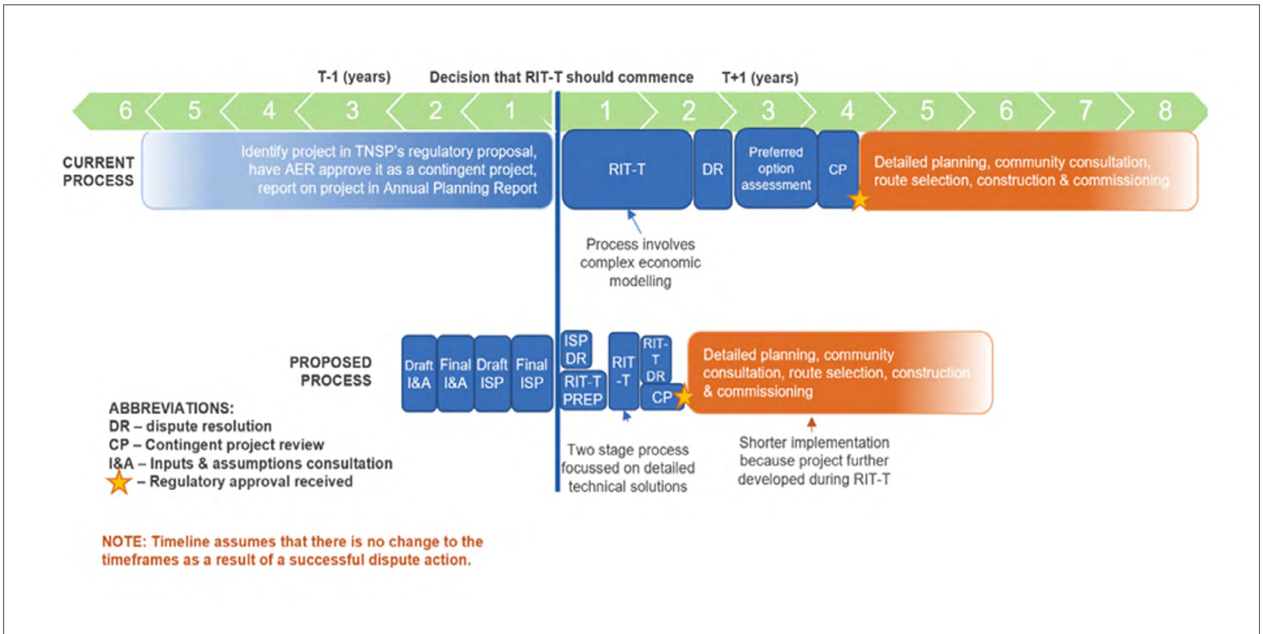
The Energy Security Board (ESB) has also responded to these concerns by implementing an accelerated RIT-T timetable for actionable ISP projects. This is illustrated in Figure 1 below.

It doesn't account for all the potential benefits

The RIT-T prescribes the kinds of benefits that can be taken into account. These are primarily "market" benefits – the cost reductions in generation that will occur from the project enabling more cheaper generation to be brought to market. They also include technical system benefits, such as improvements to reliability and security. They do not directly include emissions reduction benefits (or costs if a project was forecast to result in higher emissions) or general government policy objectives, such as increasing renewable energy investment or regional jobs.

The lack of emissions reduction benefits is consistent with the overall governance of the east coast energy system and has long been the subject of debate. It is important to note that if such benefits were included (and the same applies to other intangible benefits) and it altered the outcome of the process, then it would result in consumers paying for the costs of additional projects that would not be expected to lower overall system costs. There is an argument that consumers should not foot the bill for meeting other policy objectives no matter how well-founded those objectives are. Of course, if emissions costs were internalised into the system through carbon pricing then emissions reduction benefits would be "baked in" to the RIT-T. Energy ministers recently agreed to the introduction of an emissions objective in the National Electricity Objective (NEO) and this might influence how the RIT-T is interpreted in future.

Figure 1 *Expedited framework for actionable ISP projects*



Source: ESB

The use of cost reductions rather than price reductions in assessing the benefits avoids the risk of distorting the market for generation by using the RIT-T to chase ever lower prices. This is the tension between having entirely different methods for determining and rewarding investment in the partial substitutes of generation and transmission. Modelling price outcomes rather than simply system costs outcomes also introduces an additional layer of complexity and uncertainty into the cost-benefit evaluation.

TNSPs may not be incentivised to choose the right option

As discussed in greater detail in the Distribution paper in this series, there are concerns that network incentives may be biased towards capital expenditure (capex). This may lead a TNSP to favour a capex option over an operating expenditure option, such as payments to another party for network support.

An alternative factor may be that the process does not facilitate choices that maintain optionality in the face of uncertainty. A potential example is ElectraNet's recent decision to install four synchronous condensers in its South Australian network to address system strength and inertia. While this option clearly appeared to be the lowest cost on an annualised basis, the condensers are intended to run for twenty years. However, there is a chance they will be redundant before then, due to both the building of the interconnector to NSW (whose RIT-T followed this one) and recent evidence that grid-forming inverters that connect large renewables and batteries to the grid can provide system security services.

It is hard to evaluate general claims of bias, given the scope of the issue to be addressed in most RIT-Ts appears to point to a capex option. To date there have been few RIT-Ts that have resulted in a non-network option.

The WA regulatory test applies to all capex projects over $30m that are proposed outside of Western Power's five-year access arrangement process. There have been relatively few applications of the test in the past and given that there is not currently a major expansion of the transmission network proposed to support the energy transition, the test has not been as controversial as in the NEM. Nonetheless, the ERA recently reviewed the guidelines for carrying out the tests, which are broadly similar to those in the NEM.

Access regimes

The NEM transmission system is an open access network where new generators pay "shallow" connection charges. "Shallow" connection refers to the assets that are dedicated to that generator only (e.g. a radial line connecting a new generator to a cut in point in the existing network with no expectation that it will connect other generators). The costs of any "shared" network assets are recovered from consumers on a regional (state) basis. "Shared" means that the asset is of value to more than one participant, even if it is a small number: (e.g. a line connecting two generators to the network).

Where generators do not have to pay for shared transmission, they have no firm access rights to the network and risk being "congested off". Not all generators are exposed to this risk, in practice, however.

Policymakers have long been concerned that there is a lack of locational signal for new generators to site themselves in the optimal part of the network, although the counterargument is that Marginal Loss Factors (MLFs) and congestion serve as a signal.

Historically, there has been limited support for significant reform. Key stakeholder objections are:

- Incumbent generators argue that there is no point exposing them to a locational signal since they cannot relocate.
- New generators argue that they should not pay charges that incumbent generators did not as that would disadvantage them.
- All types of generators argue that locational marginal pricing (the AEMC's preferred solution) exposes them to unmanageable risks and that the size and configuration of the NEM does not warrant this approach. Whether the size argument is compelling is questionable given a far smaller market (Singapore) has implemented locational marginal pricing.
- TNSPs argue that their investors have chosen a low-risk business and they should not be exposed to new risks in the form of incentives to decide for themselves the least cost approach to managing congestion.

Recent regulatory developments indicate that locational marginal pricing may have been overlooked in favour of the ESB's proposed Congestion Management Mechanism for REZs, which it consulted on earlier in 2022. The ESB is especially concerned about REZs, given they will represent much of the new transmission system that new generators will connect to, so these are the key decision points for determining how much congestion will be allowed and whether that is an efficient level.

Several stakeholders proposed alternatives, which the ESB narrowed down to four for continued consideration. Two are designed to provide incentives for generators to account for congestion when deciding where to locate: the Congestion zones with connection fees and Transmission queue options. Two are designed to provide incentives for generators to account for congestion when bidding into dispatch: Congestion Management Market (CMM) with universal rebates and Congestion Relief Market (CRM). These are briefly described in Table 2 below.

In the investment timeframe, the congestion zone model will provide physical access rights to new generation, which is a clearer signal than the transmission queue approach.

In the operational timeframe, the CRM will be an opt-in model, and thus be less intrusive than the CMM, which all generators will have to participate in. However, AEMO is concerned about the costs it will incur to implement CRM.

In Western Australia, the system is in the process of transitioning from an unconstrained access model to a constrained network access model, which will be more similar to current arrangements in the NEM. In recent years, over 600MW of new renewables has been connected under a generator interim access (GIA) framework, which would not have been achievable under the unconstrained access model. A full move to constrained network access is scheduled for implementation later this year and will include grandfathering of access rights for existing generation.

Designated Network Assets

In the NEM, the AEMC has recently updated the rules in an attempt to facilitate the uptake of commercial transmission extensions where connecting generators contribute to funding the new transmission. There was already a dedicated connection agreement (DCA) process that allowed for generators to contribute to transmission extensions (beyond the basic shallow connection to the existing shared network) while receiving some protection from being constrained off that line by later generators who do not contribute. The new Designated Network Asset (DNA) rule extends these arrangements to facilitate multiple generators contributing to a network extension.

For example, the first use of the new DNA rule could be a project in NSW that seeks to connect four new generators who will collectively pay for the project through an annual service fee. In return they will effectively get "firm" capacity rights and exemption from system strength requirements on new generators.

Table 2 *Congestion management options*

INVESTMENT TIMEFRAMES	OPERATIONAL TIMEFRAMES
Congestion zones with connection fees Investors receive clear up-front signals about which network locations have available hosting capacity	**CMM with universal rebates** Single, combined-bid energy and congestion market
Transmission queue Establish a transmission queue that confers priority rights (either to be allocated rebates in the CMM or to establish who buys and sells congestion	**Congestion relief market (CRM)** Changes to the market and settlements to provide separate revenue streams for energy and congestion relief

Source: ESB

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Transmission for the transition

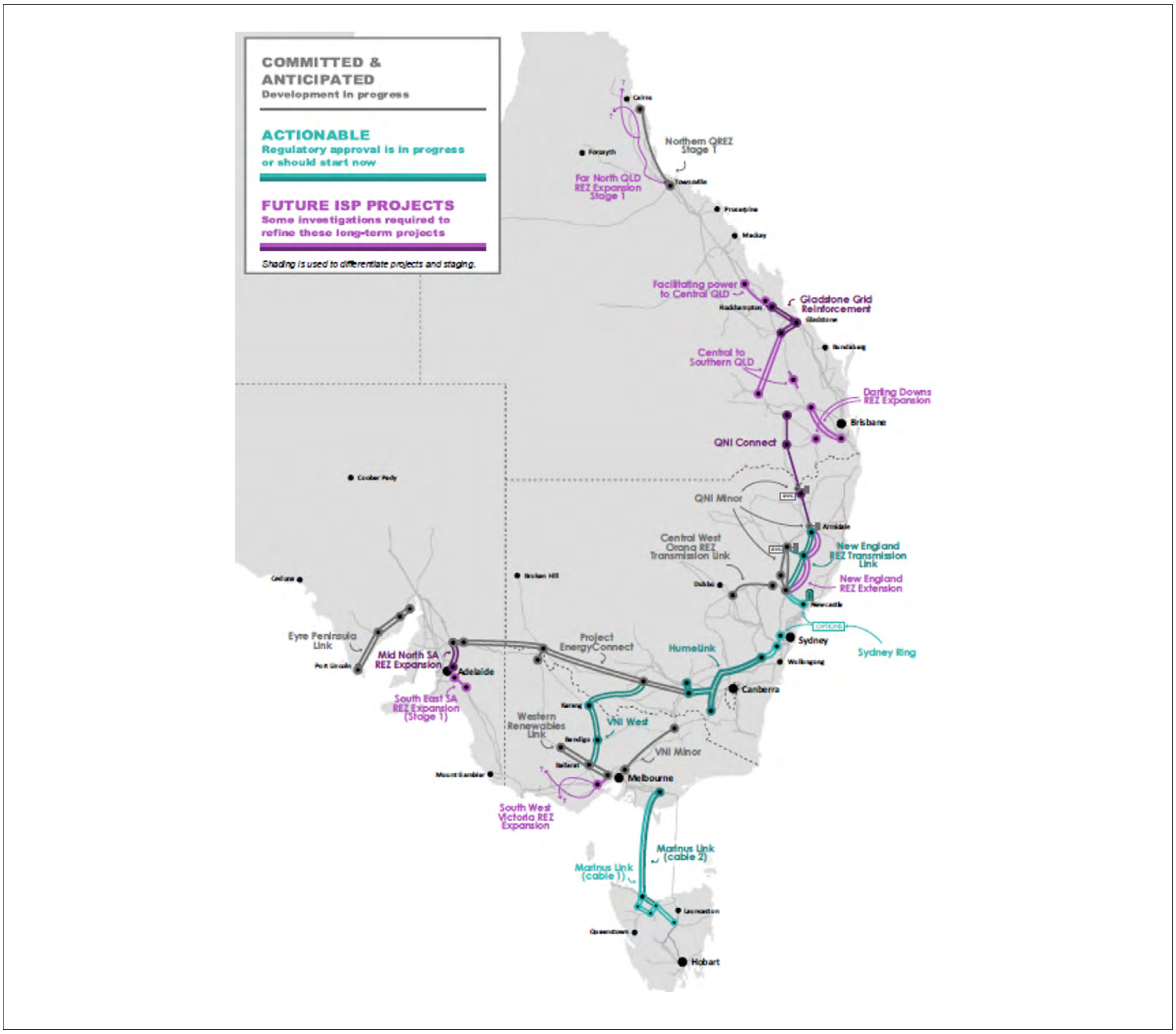
Concerns about how to deliver a transmission system to support a low carbon electricity system have been around for some time. To address these concerns, Dr Alan Finkel's Independent Review into the Future Security of the NEM recommended a "long-term integrated plan for the grid that establishes the optimal transmission network design to enable connection of renewable energy resources, including through inter-regional connections". This proposal became the Integrated System Plan (ISP), first published by AEMO in 2018. The South West interconnected System (SWIS), the network that serves south-west Western Australia has its own Whole of System Plan (WoSP).

The Integrated System Plan

The ISP focuses on proposing where major transmission investments should be made to strengthen the grid and enable new large-scale renewable investment. It does so by considering the optimal combination of generation and transmission capacity to meet a range of demand scenarios over a 20 year horizon. It models least cost systems but does not use market modelling to confirm that its proposed generation capacity will actually be commercially viable. The ISP is updated every two years.

Figure 2 below shows AEMO's latest view of how the NEM's transmission grid should be upgraded to help the system transition to net zero emissions.

Figure 2 *2022 ISP – proposed transmission infrastructure*



Source: AEMO

Transmission operators can use the ISP as a basis for proposing new investments to the AER, but each project must pass its own cost-benefit test. Energy market bodies have collaborated to streamline the transmission investment approval process in light of the many transmission projects emerging from the ISP. Critics still claim that the process takes too long: as Figure 2 above shows, the streamlined process still takes 18 months after publication of the ISP to gain regulatory approval for the project. Only at that point will the TNSP make its investment decision, and then the design, consultation and construction of the new asset can take several more years. Consumer advocates point out that consumers underwrite these projects, and the approval processes are there as an important check. They are broadly consistent with the recommendations of Infrastructure Australia for infrastructure development generally, including the need for detailed analysis of different options and independent review of the proposed project and its costs.

Governments have tried to accelerate the process. The previous Federal Government funded early works that the TNSP would not otherwise be prepared to carry out as it waited on full approval. The rules have also been tweaked to allow TNSPs to stage projects and apply for early works separately.

The current Federal Government has identified this as a priority issue and committed $20bn via its Rewiring the Nation policy to fund an accelerated rollout of transmission. Given that financing a project once it has been approved does not appear to be the major hurdle (see below for further discussions on financing) – and since the project will earn a guaranteed regulated return – it is not clear whether this policy will significantly accelerate the rollout.

The Whole of System Plan

Western Australia is not currently contemplating the same rate of change as the NEM. Its most recent long-range planning exercise, the Whole of System Plan (WoSP) envisaged that given the current level of renewable generation capacity being constructed or commissioned and the expected reduction in demand for grid-supplied electricity due to the uptake of rooftop solar, there was no need for further material investment in new generation or transmission network infrastructure in the near future.

Subsequent to the release of the WoSP, the government has announced accelerated closure of its remaining coal plants. The next WoSP, which is due in 2023, will reflect this change and this may require greater investment in both generation and transmission to connect the replacement generation.

Renewable Energy Zones

Renewable Energy Zones (REZs) are network extensions to allow the connection of large volumes of new renewables. They are an intended outworking of the ISP. Nevertheless, state governments are implementing their own approaches that they are also labelling as REZs.

Most of the new renewable capacity has to date been built close to the existing transmission network in order to minimise connection costs. As these lines become congested, the number of suitable quality sites close to spare capacity decreases. Consequently, pressure is growing to extend the network to new areas with good renewable resources. State governments are keen to see these extensions get built to help ensure their state meets its renewable energy goals.

As part of the ISP, AEMO identified up to 39 "candidate" REZs including four for offshore wind.

The current regulatory investment test (RIT-T) for new transmission projects is not well suited to deciding whether to build a REZ as the RIT is largely based on the benefits from improving the transmission of existing generation while the value of REZs is to facilitate new generation. But a generation proponent will not commit until they know the REZ will be built, which can make the business case for a REZ harder to prove.

State governments are starting to bypass the RIT-T and set up their own frameworks for developing REZs. This also allows them more influence on where and when they get built, which is not always fully aligned with the ISP.

AEMO's latest view of where REZs may be most usefully built is set out in Figure 3 below. Not all REZs will necessarily be built even by 2050. For example, in most scenarios, AEMO does not envisage offshore wind REZs to be part of its optimal development path.

Western Australia has not currently set out any plans to develop REZs for the SWIS. As noted above, if the next WOSP sets out a requirement for more renewables to replace closing coal plants, then this may change.

Interconnectors

Interconnectors are simply the term used for transmission lines (or rather collections of transmission assets) that cross state borders. An important implication of this is that market prices can vary by state – due to limitations on the volume of energy that can be transferred between the states – so the business case for interconnectors is largely predicated on increasing the opportunity for trading electricity between states and thus making the wholesale market more efficient (which should in turn mean lower

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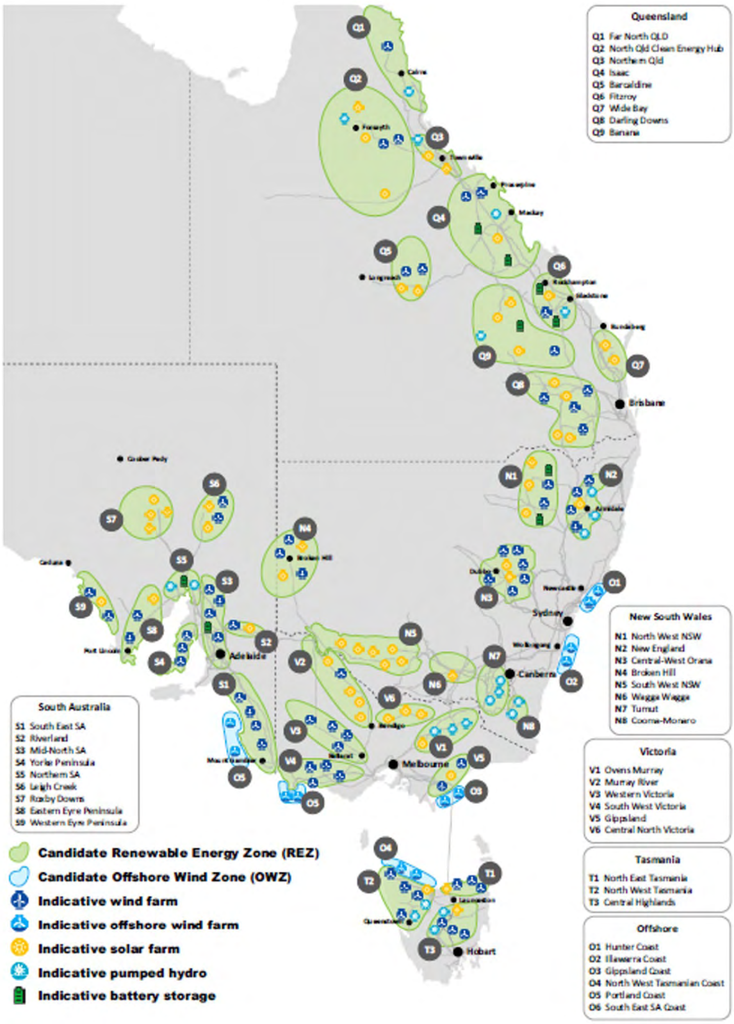
Figure 3 *Location of potential REZs, 2022ISP*



Source: AEMO

prices overall). Interconnectors are only applicable to the NEM in Australia, as the SWIS lies entirely within Western Australia's borders and does not have multiple regions.

Interconnectors are paid for according to the same rules as the rest of the transmission network – customers in the state where the asset is built pay for it over several decades. But this allocation of costs depends on the geographical split of the assets and may not relate to how much each set of customers benefits through lower prices in their region.

This is mitigated somewhat by interregional transmission use of system charges (IR-TUOS). AEMO looks at the net flows of each interconnector annually and allows the net exporting TNSP to charge the net importing TNSP (with flow on impacts for the consumers in each region). But this is only an approximation of the benefits as it relates only to the volume of the energy flows, not the value of the energy at the time of import/export or the price difference between regions. Because interconnectors have two-way flows and are 'netted-off', the IR-TUOS charges tend to be also very small compared to the true costs and benefits of interconnection.

This is proving to be a sticking point for the proposed second interconnector between Tasmania and the mainland, Marinus Link, which is intended to proceed as regulated transmission with its costs directly payable by end-use customers. Tasmania's population and customer load is much smaller than Victoria, so the cost per customer will be much higher there if the costs are evenly shared. Additionally, cost allocation between Victoria and Tasmania is subject to uncertainty as there is no NEM regional boundary and much of the cable route lies in seabed vested in the Federal Government.

According to the Marinus RIT-T final conclusions report, the primary beneficiaries of Marinus are expected to be mainland customers benefiting from northward flows of firmed Tasmanian based renewable capacity, whilst lower value energy will dominate southward interconnector flows. These issues did not arise for the existing interconnector, Basslink, which is the only remaining "merchant" interconnector in the NEM. The company that owns Basslink is currently in receivership with ongoing arrangements set to be determined by its future owners.

In principle, Victoria and Tasmania could strike a bilateral deal to share the costs differently. This happened when South Australia and Victoria were first connected. But this outcome and its politics are not straightforward and would require Victoria to take on a larger share of the costs than implied by the current rules.

The NEM's transmission planning cost-benefit framework is already supported by economic modelling which is necessary to show that the total market benefits of an interconnector project exceed its cost. It does not matter where those benefits fall – it could be customers anywhere, or even generators who benefit from the interconnector.

TasNetworks, who would build the Tasmanian side of Marinus Link, has proposed a new model to apply to Marinus Link and other new interconnectors (but not the existing ones). It notes that the regulatory test for whether transmission is worth building requires economic modelling of market outcomes with and without the new interconnector. It argues that the modelling can determine the incidence of the customer benefits (i.e., it can identify which states' customers benefit and by how much). The relative proportions are then used to determine what shares of the new project will be allocated to each states' customers. At face value this process seems fair, but it comes with some complexities, for example not all beneficiaries are customers (some are generators), and the process places heavy reliance on the specifics of the modelled outcomes at the time of the regulatory test.

Jurisdictional developments

While the SWIS lies fully within Western Australia and is subject only to state oversight, the governance arrangements for the NEM are more complex. NEM-wide arrangements were set up in 2001 following the signing of the Australian Energy Market Agreement between the Commonwealth and the states and territories. For many years, the states stayed at arm's length from transmission planning and access issues, but in recent years as several states have developed their own net zero and renewables policies, they have also become frustrated with perceived barriers to those policies arising from the NEM framework for transmission.

Accordingly, individual states have begun to develop their own transmission policies and planning bodies. This is likely to lead to a pattern of sub-optimal investment because state bodies will not take a system-wide perspective and their processes will not be fully integrated into the ISP. A fuller description of jurisdictional policies of the NEM states is set out in Appendix 1.

Local planning issues

While much effort has been expended considering how the electricity regulatory framework does or does not support an efficient and timely rollout of new infrastructure, relatively little consideration has been given to the fact that an AER-approved project still must apply for local planning permission, consult with affected parties along the route and comply with jurisdictional requirements on environmental impacts, among other things.

Given the scale and importance of projects, planning approval will typically be determined at state level.

Formal planning approval is not necessarily the only hurdle. Social licence cannot be taken for granted, as evidenced by the extensive opposition to the Western Victoria Transmission Network project.

Planning approval may also come with conditions that can materially impact the overall cost of a project. NSW transmission projects come under the scope of the state's Biodiversity Offsets Scheme, which requires project proponents to mitigate any unavoidable environmental impact of their project by paying for environmental improvements elsewhere. While the allowed cost of offsets for the NSW section of Project EnergyConnect was $125m (some $41m less than requested by Transgrid) or 7 percent of the costs, the estimate for HumeLink is $935m, or 28 per cent of the total costs. These costs are at least a partial explanation for why final project cost estimates are coming out so much higher than in the ISP. As the incidence of these costs is becomes clearer, they can be more readily factored into earlier estimates of future projects.

It is not uncommon for objectors to large transmission projects to opine that the lines should simply go underground. In Germany, the government chose to underground a new project known as Suedlink in response to public opposition to the major north-south transmission connection. This decision resulted in a trebling of costs to approximately €10bn. Some local opposition still exists.

Conclusion

That Australia's energy systems will need new transmission investment to support the transition from a coal-dominated system to a renewables dominated system is not in doubt. The larger issue to be addressed is how to manage investment decisions so customers can benefit from the lowest cost system that is achievable? This is the focus of current reform efforts, which are hampered by wide disagreement among stakeholders as to who should bear the risks of poor decision-making or the costs of managing congestion on the system.

Into this gap have come governments at both federal and state level. This has elevated the risk of poor planning and decision-making as a result of too many stakeholders being involved. Planning and decision-making in the NEM is now shared among AEMO (via the ISP), individual TNSPs (for in-state projects), AER (regulatory sign-off), state governments (various roles, varying by state) and the Federal Government (potentially very significantly via its new Rewiring the Nation policy). While there is no perfect answer, at a minimum, closer co-ordination amongst these parties, and clearer delineation of roles is required to facilitate an orderly and efficient transition.

There is no doubt that planning transmission is complex, from design, to justification, to financing, to construction. Given more is required it is natural that policy makers will want to see these hurdles smoothed. However, major augmentations cost billions of dollars and decision-makers do not always bear the risk of their decisions. Therefore, complexity may not be a bad thing.

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Appendix 1: Jurisdictional policies

NSW

NSW, although not the first state to move to take greater control over intrastate transmission developments, has the most ambitious plan and is already implementing it, via its Electricity Infrastructure Roadmap.

The Roadmap is expected to deliver five REZs for NSW, under the purview of EnergyCo, a new government agency. In each case, EnergyCo will lead community consultation in an attempt to ensure social licence for the REZs and connecting generation. It will solicit expressions of interest (EOI) from potential generators in each zone to gauge interest in connecting to the REZ, which will inform the final detailed specification of the REZ. It will also design a REZ access standard for each zone to streamline connection processes for new generation.

The risk that a new REZ will have insufficient new generation connected will be mitigated by the NSW government's parallel process to provide supporting contracts for new renewable generation and storage.

The first REZ to be developed is the Central-West Orana REZ. The EOI process in June 2020 elicited 113 registrations of interest for the Central-West Orana REZ, representing 27 gigawatts of new energy generation and storage projects. This was considerably more potential capacity than needed to justify the REZ and in November 2021 the energy Minister "declared" the REZ. EnergyCo is tendering for the construction and operation of the REZ and is consulting on the access standards. This approach increases the number of contestable projects in the NEM which could help to foster competition in the provision of transmission services (however while Victorian projects are in principle contestable, they are generally won by the incumbent, AusNet).

There have been additional developments in NSW outside of the government processes. TransGrid's commercial arm, Lumea, ran its own EOI for connection to a new transmission line in New England. Sufficient credible applications were received to more than achieve the maximum 1,400MW of transfer capacity on the line. Accordingly, Lumea is seeking planning approval to go ahead with the project. The project is being carried out under the new DNA arrangements.

Another independent enterprise looking to build new transmission is Walcha Energy. This is a collection of potential new developments (solar, wind and storage) where the proponent is also looking to build their own transmission to connect all the projects into the rest of the network.

Both these projects are in New England which is the second REZ under development by EnergyCo. It is unclear how the three projects interact.

If either or both of these end up being constructed it will serve as a useful test case demonstrating the viability of alternative routes to developing transmission that are not reliant on customer funding, the lengthy RIT-T process, or government facilitation.

Victoria

Victoria was the first NEM jurisdiction to move to formally drive new transmission investment intra-state. It passed enabling legislation in early 2020. This allowed it to bypass existing regulatory arrangements and specify requirements for new electricity infrastructure (potentially including storage and generation as well as transmission), implement its own decision process for deciding whether projects should go ahead and the means to recover the costs from customers (most likely via network charges).

The first project carried out under these arrangements was the Victoria Big Battery near Geelong. Its main role is to facilitate extra transmission capacity.

In order to determine and carry out other projects, the Victorian Government has allocated $540 million in funding to a new body called VicGrid. It will serve as an independent agency to oversee development of up to six REZs. Recently, the Victorian government began consultation on its transmission investment framework.

Queensland

The Queensland Government owns the local TNSP, Powerlink, and so it has less need than NSW or Victoria to set up additional agencies to manage transmission expansion in the state. It also has less urgency – the current actionable ISP projects are not in Queensland. To date, Queensland has identified three REZs and is providing some initial funding.

In addition to this, there is a private proposal to develop a transmission connection, known as CopperString between the NEM and the area around Mt Isa, which is currently an energy "island". The Queensland Government is currently considering electricity supply options for this area, also known as the Northwest Minerals Province. Under a high demand scenario where several new mines open, one option for additional supply is to connect it to the NEM. This could be carried out under a RIT-T, or the Queensland Government could bypass the RIT-T if it considered that there would be material economic benefits not picked up in the RIT-T. In either case, Queensland consumers would cover a significant portion of the $2.5bn cost, even though it is not clear that they would get any direct benefit.

South Australia

South Australia already has higher renewable penetration than the rest of the mainland NEM and therefore there is less drive to develop new REZs. Additionally, none of the Actionable ISP projects are in South Australia. The South Australian government has been supportive of EnergyConnect which will also function as a REZ, but this support does not require it to contribute funding or derogate from NEM frameworks.

Tasmania

Tasmania also has high levels of existing renewable generation. In fact, it is all but 100 per cent renewable. However, it sees an opportunity to export more clean energy to the mainland through some hydro upgrades and new wind farms. To do this, it needs another interconnector in addition to the existing Basslink.

As discussed above, this 2nd interconnector, MarinusLink is strongly supported by the government, but their concern is that if it goes ahead under the RIT-T, Tasmanian customers will pay a significant proportion of the cost. Given Tasmania has far fewer customers than the mainland, this is a cost impost they would like to avoid.

Appendix 2: Case study – Project EnergyConnect

EnergyConnect is a transmission line connecting the existing power grids in South Australia and New South Wales. The interconnector will run from Robertstown in South Australia to Wagga Wagga in New South Wales, with a spur line into the north section of the transmission network in Victoria. It will be rated at 330kV and have a maximum transfer capacity of 1500MW – equivalent to a medium-sized coal plant. It was first proposed by South Australia's TNSP ElectraNet in November 2016. At that time, the rationale for the interconnector was:

- The closure of Northern Power station earlier that year had resulted in much higher wholesale prices in South Australia than in neighbouring states – futures prices indicated an average $35-$45/MWh premium;
- improving security of electricity supply in South Australia, especially when it is separated from Victoria by an event which prevents use of the Heywood interconnector with Victoria, and;
- enabling more renewable generators to effectively connect to the system.

ElectraNet's proposal was backed in the original Integrated System Plan, published by AEMO in June 2018. At this point, it was called Riverlink, and was estimated to cost $1.27bn (+/-50%).

The second step was the cost-benefit analysis, which ElectraNet published in July 2018, just after the ISP. ElectraNet put the cost at $1.5bn, which was already a 20 per cent increase on the AEMO ISP figure. But its modelling suggested $1bn of "net benefits". The main saving was the avoided fuel costs from gas generators in South Australia as they were displaced by cheaper generation (mostly black coal) in NSW. The interconnector would also reduce the need to keep two gas plants on at all times in South Australia to ensure system strength (the grid's ability to recover quickly from faults). ElectraNet noted that later, as coal plant in NSW retired, there would be savings in that jurisdiction because imports of renewables from South Australia would mean avoided costs of building new gas plants. At this point the price premium for South Australia power was around $14-18/MWh.

The other major source of financial benefit was the closer connection to proposed new REZs the interconnector would enable.

The final cost benefit analysis in February 2019 largely confirmed the above, although the expected net benefits had fallen slightly to $900m. In the meantime, state governments had already started funding early works so that if the project was approved, ElectraNet and Transgrid would be ready to go.

Next, the AER had to review the cost-benefit analysis. This step was delayed because several consumer representatives were concerned that consumers would foot the bill for the project but they were not convinced they would see the benefits, and one of them (SACOSS) lodged a formal dispute. The AER decided that ElectraNet had complied with the rules and they would consider SACOSS's issues in their overall review. They asked ElectraNet to re-run their modelling. The re-run modelling still showed net benefits, and the AER declared the project had passed the test in January 2020.

Following approval, Transgrid and ElectraNet were able to develop the scope of the project in more detail and tender for the main construction works. Once received, they could go back to the AER with a contingent project application which would confirm the costs recoverable from customers.

The TNSPs submitted their cost claims in September 2020. The cost had risen to $2.382bn, a 56 percent increase in nine months. New modelling, consistent with AEMO's latest ISP, indicated the benefits had also increased. For example, more projects had passed the RIT-T in the meantime, meaning that firming capacity from Snowy 2.0 could flow to SA.

In May 2021, the AER confirmed it would approve the build cost at $2.275bn. The TNSPs had already confirmed they would go ahead if approved and funding was obtained. Transgrid confirmed it had secured financing, thanks to the CEFC.

Large amounts of change occurred in the five years from initial proposal to final sign-off. There is a lot of uncertainty about whether AEMO will continue to require two gas generators to run in South Australia with or without the interconnector. The South Australia system services that EnergyConnect was designed to support may be largely supplied by new synchronous condensers (built by ElectraNet) and various big batteries that have been installed on the South Australia grid. The energy plan for NSW looks designed to ensure NSW builds plenty of its own renewables and back-up capacity, which could impact the interconnector's utilisation.

Herein lies the challenge of building large new pieces of infrastructure in the NEM. There is a constantly moving target to chase when assessing the value of the investment.