Centre for Energy and
Environmental Markets

Cluster Project 4 – Robust energy policy frameworks for investment in the future grid: Deliverable Report 1b: Connecting Remote Renewables

by

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Contents

List of Figures

List of Tables

List of Acronyms

Acronym	Definition
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AIG	All Island Grid
APR	Annual Planning Report
CAISO	Californian Independent System Operator
CEC	California Energy Commission
CO2	Carbon dioxide
CPUC	Californian Public Utilities Commission
CREZ	Competitive Renewable Energy Zones
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CTPG	California Transmission Planning Group
DC	Direct current
DNSP	Distribution Network Service Provider
DTSO	Declared Transmission System Operator
ERA	Energy Resource Areas
ERCOT	Electricity Reliability Council of Texas
ESOO	Electricity Statement of Opportunities
FERC	Federal Energy Regulatory Commission
GIP	Generator Interconnection Procedures
GIPR	Generation Interconnection Process Reform
GPA	Group Processing Approach
GW	Giga-Watt
LCRI	Location Constrained Resource Interconnection
LCRIF	Location Constrained Resource Interconnection Facilities
MCE	Ministerial Council on Energy
MISO	Midwest Independent Transmission System Operator
MVP	Multi Value Projects
MW	Mega-Watt
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NPV	Net present value

NTNDP	National Transmission Network Development Plan
OFA	Optional Firm Access
PUCT	Public Utility Commission of Texas
REFIT	Renewable Energy Feed-in Tariff
RET	Renewable Energy Target
RETI	Renewable Energy Transmission Initiative
RETPP	Renewable Energy Transmission Planning Process
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Operator
SCER	Standing Council on Energy and Resources
SEM	Single Electricity Market
SENE	Scale Efficient Network Extension
SONI	Single Electricity Market Operator
TAC	Transmission Access Charge
TFR	Transmission Frameworks Review
TNSP	Transmission Network Service Provider
UK	United Kingdom
WECC	Western Electricity Coordination Council

1 Introduction

1.1 CSIRO Cluster Project Background

The broad objectives of this CSIRO Cluster project are:

- The development and application of an interdisciplinary policy assessment framework to better understand and assess existing and proposed policy options for driving appropriate investment in the electricity industry given its unique technical(e.g. system security), economic (e.g. network investment) and wider social (e.g. affordability imperatives) characteristics. A key focus is on the interactions between these policies.
- Development of a high level (i.e. focused on broader policy relevant perspectives rather than just detailed technical and economic modelling) quantitative policy analysis tool for exploring the potential impact of different policies on the most economic future electricity generation portfolios.
- Application of this policy assessment framework and quantitative policy analysis tool to develop high level insights on coherent and comprehensive climate and energy policy frameworks to drive appropriate investment in the future grid. A particular focus is on maximising the synergies and minimising possible conflicts between multiple policy instruments such as, for example, might be seen with renewable energy targets and network investment drivers.

1.2 Scope of this report

This report represents the second agreed milestone for the project: a literature review on Australian and international policy options.

The issue of policy frameworks for future grids is complex and multifaceted. This means that there is a correspondingly vast array of relevant literature. To ensure productive outcomes, we have elected to focus our efforts in this literature review on the following areas:

- ***Transmission networks*** – The review will target transmission level networks, rather than distribution level networks. There are many significant issues relating to the evolution of distribution networks in future, but these are quite different in nature and deserving of independent analysis focused solely in this area.
- ***National Electricity Market*** – This review will focus on the National Electricity Market (NEM), which serves around 80% of the electrical load in Australia. The regulatory frameworks for grid planning and investment in Western Australia, the Northern Territory, and off-grid locations will not be dealt with in this review.

- ***Drivers for asset location*** – The review will focus on the factors that influence the ways in which locational decisions are made, both for new transmission assets and new generation investments (since these are highly inter-dependent).
- ***Drivers for asset size*** – The review will focus on the factors that influence the ways in which transmission augmentation sizing decisions are made. This includes consideration of the scale efficient sizing of connection assets for remote renewable projects, as well as optimal levels of congestion and appropriate incentives for sizing of transmission assets related to variable renewable generation.

The following questions have been used to guide the review:

The Australian experience to date

1) What is the current approach to transmission investment in Australia?
2) Where does it work well, and where has it failed?
3) What reforms are under consideration or implementation, and what are the motivations for that reform?
4) What new challenges may arise in future, and is the current approach likely to successfully handle those new challenges?

International experiences

1) What alternative models have been applied in other nations?
2) How have those models been successful, and where did they fail?
3) What reforms are under consideration or implementation, and what are the motivations for that reform?
4) What are the key learnings for Australia?
5) Are there any factors that make the Australian context unique, such that models applied internationally may work differently in Australia?

1.3 Structure of this report

This report is organised in two parts. Part A explores the general regulatory and market frameworks that drive decisions on transmission location and size. General theory from international research is outlined, followed by an outline of the Australian framework applied at present. Current reforms and processes exploring change in Australia are then outlined, leading to a summary of issues for further consideration.

Part B of the report considers the special case of connection of remote renewable resources to the grid. The Australian experience to date is outlined, including the 2010 review on Scale Efficient Network Expansion (SENEs). This is compared with a range of international models. Part B concludes with a description of the implications of current reforms, and recommendations of issues for further consideration.

2 Connecting remote renewables

The development of transmission to connect remote renewable generation projects to the grid is a relatively special case in the broader area of transmission operation and investment. The electricity industry has, of course, undertaken major network extensions in the past to connect up remote conventional generation (such as, for example, hydro generation) or serve growing remote loads (for example, connection to large mining operations). However, these decisions were typically undertaken within the context of centralised and vertically integrated monopoly electricity utilities.

Restructured industries therefore face new challenges with such remote renewable generation opportunities. These projects are often larger than usual, and in many cases could represent a significant augmentation to the main grid backbone. Furthermore, the utilisation of the new augmentation may be dependent upon the decisions of a small number of stakeholders. Therefore, uncertainty is exacerbated beyond typical levels, and the risks of under or over investment are higher than usual. The question of who should bear the costs, risks and potential benefits associated with these developments is therefore especially important.

For these reasons, the policy and regulatory frameworks that manage the development of transmission to connect remote renewable projects has been considered deserving of further in-depth analysis.

This is an issue that is especially pertinent for Australia, given the large geographical distances involved, and the remoteness of many of the highest quality (underlying energy density and availability) renewable resources available. Examples include engineered geothermal opportunities in central Australia, and the improved direct solar irradiance for solar thermal generation available in inland NSW and Queensland. It is also a highly timely issue, given the rapid transformation of the electricity sector that is required over the coming decades to effectively address our climate change and other challenges. It is anticipated that significant development of renewable resources will need to occur to achieve electricity sector emission reductions of the scale and speed that appears required. The efficient development of the connecting network in a co-optimised fashion could lead to significant cost reductions for consumers in comparison to options which either fail to access these remote renewable energy opportunities, or do so in a poorly planned manner.

2.1 Australian experience to date

2.1.1 The current framework in Australia

The arrangements for network connections and the construction and funding of network extensions in the NEM are set out in Chapters 5 and 6A of the National Electricity Rules (NER). Essentially, the NEM operates an open access regime whereby network companies are obliged to facilitate connections to the shared network, subject to security and reliability requirements. The market also uses the 'causer pays' principle such that when transmission costs can be attributed to a specific user, that party should be liable for the costs incurred. In the case of connecting a single remote renewable energy project the costs attributable to that generator would typically be unambiguous.

Broadly, there are two options for the transmission connection services available to a new-entrant generator at present [1]:

- A transmission investment can be a Prescribed transmission service if it has passed the RIT-T. In this situation the funding is recovered from the customer base of the network utility.
- The network utility can provide either a Negotiated or a Non-regulated transmission service whereby the new transmission asset is funded by the generator.

The AEMC has demonstrated that there are barriers to this type of investment occurring via either of the two options noted above.

Applying the RIT-T to the investment is likely to be problematic, in part due to the difficulties in defining the base case and alternative options that the proposal will be compared against [1]. The allocation of potential benefits such as lower RET certificate prices (as contemplated in [2]), or lower pool prices, owing to subsequent renewable energy connections would also be problematic because market contracts limit the extent to which these benefits can be passed onto customers.

Typically it would not be feasible for a remote renewable generator to fund and build a long transmission line to connect to the shared network. This is due to the high cost of transmission infrastructure, and the specific characteristics of wind and solar projects. This has been addressed in Australian and International studies, including [2] and [3]. Instead, a viable option may be for the transmission costs to be shared if multiple generators were to connect in the same area. If generators are ready to connect simultaneously this can be coordinated. However, if connections are expected over a period of time it may be efficient to initially oversize a transmission asset to cater for the expected future connections.

There are disincentives for a generator, or group of generators, to fund the transmission line because under the current framework those generators would not be able to own the asset, have control over who can connect to it, or have guaranteed access rights to use it [1, 4]. In [1], the AEMC notes that: "The lack of clarity regarding access rights…may provide a disincentive for first mover generators to fund additional capacity". This situation represents a first mover disadvantage and the free rider problem in that non-funding generators could subsequently connect at lesser expense.

Owing to these barriers, as well as the current availability of high quality renewable resources in locations closer to the grid, transmission-connected wind and solar energy developments to date have typically not been in remote areas. As shown in Table 1, some of the largest wind farms are relatively close to existing transmission lines.

Table 1 Wind farm proximity to existing transmission lines

Wind farm	Size (MW)	Proximity to transmission line
Macarthur	420	11km from an existing 500 kV line [5]
Collgar	206	Adjacent to a 220 kV line [6]
Capital and Woodlawn	198	Turbines between 1 and 15km from substation and 330 kV line
Woolnorth	140	42 km 110 kV connection to existing network [7]

As the most easily and economically accessible renewable energy resources are utilised, it is expected that more remote resources will be considered. Such resources are currently considered to be 'stranded' as they are not close to existing transmission infrastructure. For example, the wind resource of King Island in the Tasman Strait has been described as being stranded [8], although Hydro Tasmania is currently conducting a feasibility study for a new interconnector that would allow access. Also a study has demonstrated how 2000 MW of wind energy on the Eyre Peninsular in South Australia could be 'unlocked' by a series of transmission investments [9]. Looking further ahead, the viability of geothermal energy is dependent on connecting these very remote locations; projects in the Cooper Basin could require transmission lines of around 1000 km in length [2]. The efficient development of remote projects such as these will likely require shared transmission assets, and therefore shared capital costs, for these resources to be accessed.

2.1.2 The Scale Efficient Network Extensions Rule Change

The issues discussed above were contemplated in a 2008 market review undertaken by the AEMC. The *Review of the Energy Market Frameworks in light of Climate Change Policies* considered whether existing frameworks would operate efficiency once an emissions trading scheme and an expanded Renewable Energy Target (RET) were implemented [10]. It was anticipated that the RET would cause the establishment of clusters of new renewable generators in certain remote areas. However, the existing frameworks are not well structured to capture the efficiency gains from connecting these generators in clusters when these generators are not connecting at the same time. As well as the first mover disadvantage and free rider problem noted above, there is also no incentive for network utilities to oversize a transmission asset in anticipation of generators connecting the future.

The SENE proposal

To address this, the AEMC recommended that the Ministerial Council on Energy (MCE, now the Standing Committee on Energy and Resources (SCER)) submit a Rule change proposal for Scale Efficient Network Extensions (SENEs); the MCE did so in December 2009. The AEMC subsequently published a Consultation Paper [11] that details the key elements of the SENE proposal:

i. the Australian Energy Market Operator (AEMO) to identify possible SENE zones as part of the National Transmission Network Development Plan (NTNDP);

ii. NSPs to identify credible connection asset options for the SENE zones identified by AEMO and undertake preliminary planning, to be reported in their Annual Planning Report (APR);
iii. NSPs to publish a planning report and standard connection offer for each SENE zone, including technical design issues and annual charges payable by generators who connect to that asset based on a forecast generation profile;
iv. AEMO and the Australian Energy Regulator (AER) to have regulatory oversight roles, including a requirement that AEMO reviews the relevant NSP's forecast generation profile and an opportunity for the AER to disallow the project;
v. the connection offer to contain an agreed power transfer capability, including compensation arrangements where a generator is constrained off below its agreed capability;
vi. construction of the SENE to be triggered by agreement on the connection offer by at least one generator;
vii. a charging framework that requires connecting generators to pay for the share of SENEs that they use. Consumers would pay for any revenue requirement not recovered from generators, where fewer generators connect or connect later than was planned for; and
viii. a review of the policy to be undertaken by the AEMC and provided to the MCE after five years to ensure the anticipated benefits are being achieved.

During the course of the *Climate Change Policies* market review, stakeholders provided examples of the potential benefits of SENEs. A Victorian Distribution Network Service Provider (DNSP) identified a circumstance where four generators could be connected over 35 km of line at a saving of $12 million over the alternative where they were each connected individually [12]. Grid Australia gave an illustrative example in which there was a 50% saving on the capital cost to generators from using the SENE approach [13]. The AEMC considered that the potential for scale efficiencies was greater at the transmission level than at for the distribution network [14].

Rule change process

Following the Consultation Paper the AEMC published an Options Paper [1] in which it observed that the initial support for the proposal had, "been tempered by the complex nature of the proposed Rule and the implementation difficulties that it poses". A key concern was that consumers were exposed to the risk of stranded transmission assets.

The Options Paper presented five options. Options 1 and 2 were similar to the original SENE proposal; the key differences were that they both specified that 25% of the SENE must be subscribed to before it could be built, and Option 2 included an economic test for market benefit and excluded regulated compensation. Under Option 3 the first generator would pay their stand-alone cost and a RIT-T would be performed on any additional capacity. The additional capacity would be funded permanently by TNSP customers, while generators connecting in the future would contribute to the initial costs of the first generator to connect. Option 4 also involved a RIT-T on the capacity above the needs of the first generator; however the cost of the incremental capacity would be transferred to generators connecting in the future rather than remaining with the TNSP customer base. In Option 5, a RIT-T was performed on the whole SENE, if it passed then all generators (including the first generator) would pay their proportional cost (i.e. the cost they would pay when the SENE is fully subscribed), as opposed to the stand alone cost specified in Options 3 and 4.

The options were assessed against five criteria:

- generators are able to connect in a timely manner;
- generators face efficient locational signals;
- potential to capture scale economies;
- frameworks are not overly complex; and
- stranded asset risk is appropriately managed.

Analysis by Wright [15] of stakeholder submissions demonstrates the lack of consensus as to which option, if any, was the most suitable. Eight submissions opposed the proposals, 10 were in favour, and a further eight were undecided or neutral. Wright observed that stakeholders who benefit under the current arrangements opposed the proposal, while those in favour included utilities with investments in renewable energy and organisations seeking to encourage the uptake of renewable energy.

Following the Options Paper, the AEMC published the Draft Rule [14]. In the Draft Rule the AEMC proposed a “more preferable Rule” which was different from both the original proposal by the MCE and the five options presented in the Options Paper. Despite stakeholder concern that the new proposal was inadequate and “essentially upholds the status quo”, the Draft Rule was maintained in the promulgation of the Final Rule.

The Final Rule is compared with the original proposal in

Table 2. The Final Rule specifies that a TNSP is to investigate the potential for a SENE if the investigation is requested and funded by a project proponent. The scope of the study will be established through negotiations between the TNSP and the entity requesting the study; the completed study is to be published on the website of the TNSP. Equipped with this information, developers and other market participants are then able to decide whether or not to fund the SENE. As the pre-existing framework remained unchanged, the party funding the SENE would not be able to own, operate or control the asset, nor influence who may or may not connect to it.

Table 2 Comparison between the Proposed Rule and the Final Rule for SENE

Key design feature	Proposed Rule	Final Rule
Trigger for considering a SENE	AEMO to identify SENE zones, NSPs to identify credible options for connection to network.	Any entity willing to fund a SENE feasibility study can request the TNSP to undertake the study.
Investment test	Signed connection agreement with at least one generator. Consultation on optimum size of asset.	Whether or not an entity is willing to fund the SENE and bear the associated risks.
Cost allocation and charging methodology	Generators pay for share of the SENE that they use. Consumers pay for any revenue requirement not recovered from generators.	SENE funded by generator, TNSP, government, or other third party. Terms by which SENE funder is reimbursed are subject to negotiation with TNSP.
Access provisions	Connection offer contains an agreed power transfer capacity and compensation provisions if generator is constrained-off below this agreed transfer capacity.	Existing connections framework. Any subsequent generators could negotiate with TNSP for connection; SENE funder no influence in decision.
Regulatory oversight	AEMO to review NSP forecasts, while AER has power to disallow project.	No explicit role. Enforcement of National Electricity Rules by AER.

Reasoning behind decision

The AEMC judged that the Final Rule, by allowing for the identification of potential benefits of a SENE, would allow for generators to make more efficient investment decisions. It overcomes any information asymmetry between TNSPs and other market participants while protecting consumers from the risk of stranded assets. The AEMC's reasoning for why the Final Rule would be more efficient than the options previously considered was threefold:

- It more efficiently allocates the risk of stranded assets by allocating it to those best able to willing to manage the risk, i.e. market participants and investors rather than consumers.
- It maintains a market-based approach rather than requiring non-market facing entities (i.e. AEMO and the AER) to take risks on generator investment decisions.
- It is less complex as it maintains the current arrangements for access and connection.

In analysis by Wright [15] it is deemed unlikely that any SENE will be progressed under the Final Rule. It is demonstrated that the Final Rule does not provide any incentive for generators or TNSPs to construct a SENE; nor does not correct the first mover disadvantage.

In light of this, the decision of the AEMC can be explained by the scope of the National Electricity Objective (NEO). It is notable that this objective does not contain an environmental objective [16]:

> *"To promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to –*
>
> *a. price, quality, safety, reliability and security of supply of electricity; and*
>
> *b. the reliability, safety and security of the national electricity system."*

All rule changes must promote the NEO. As discussed by Wright [15], during the SENE rule change process the NEO did not allow for the full quantification of potential SENE project benefits. In regards to the RET, the AEMC states:

> *"It is…not our role to ensure the RET is met, but to ensure any behavioural changes as a result of the RET are accommodated in the most efficient way" [1]*
>
> *"It is the governments' role to ensure that environmental policy objectives are met" [14]*

In promoting the NEO, the AEMC sought to ensure that transmission and generation investment would occur in an efficient manner. An inefficient outcome would involve the duplication of assets if multiple generators connected in the same area but did not coordinate their investments. Understandably this would incur unnecessary cost on consumers. The AEMC decided that the Final Rule was enough to avoid this situation. Owing to the AEMC's position on the RET, the decision was not intended to encourage efficient investment, rather to discourage inefficient investment.

2.1.3 Victorian clusters experience

In Victoria, transmission investment is managed differently to the other NEM regions; the functions undertaken by TNSPs in other jurisdictions are split between AEMO and Declared Transmission System Operators (DTSOs) [4]. Under this arrangement, AEMO is responsible for planning and procuring new transmission capacity and for connecting generators and customers to the electricity transmission network [17]. In this capacity AEMO has developed a methodology for identifying generation clusters [18]. This was done in response to a large number of connection requests for connections to the 500 kV lines between Moorabool and Heywood, and to the 220 kV lines between Moorabool and Ballarat.

In the methodology AEMO discusses three options for connecting new generators:

1. establishing a new terminal station for each new generator;
2. connecting a generator to an existing terminal; or,
3. creating a new connection hub.

The first option has potentially negative implications for network reliability if multiple generators connect is close proximity to one another. The availability of the line would also be affected by a greater number of planned outages as the connections are commissioned – AEMO estimates that 600 hours of outages are required to connect a new terminal station. The second option relies on the locational constraints of the generator, and whether there is spare capacity at the existing terminal. For these reasons, AEMO cites benefits in terms of reliability, reduced outages, easier network expansion for future connections, and potential scale efficiencies, from using a hub approach (option three).

The criteria that AEMO proposes to use to assess potential hub connection are:

- Whether the concentration of energy resources around the hub are sufficient to make a generation cluster
- Proximity to an existing transmission line corridor
- Accessibility for construction and availability of suitable transport infrastructure
- Whether there are sufficient generation enquiries and connection applications
- Overall cost of connecting generators to the hub
- Ability to mitigate environmental impacts related to line easements and the physical establishment of the connections
- Availability of land for line easements or terminal stations

An assessment using these criteria has been conducted for potential locations in Regional Victoria and the South-West Corridor [18]. The potential hub locations received a tick or a cross for each criterion, leaving each with a rating out of 7 that corresponds to the number of ticks received. In this process each criterion has an equal weighting.

As the Victorian transmission network planner, AEMO responds to developer interest in connecting to the network. The clusters methodology it is a planning exercise that seeks to solve the technical issues associated with connecting multiple generators to the shared network. For this reason it does not propose an investment trigger, nor discuss the risk of stranded assets, other than to say that this risk could be reduced by the staged development of the hubs. This approach to risk reduction has been modelled by Chattopadhyay [19].

While the allocation of risk would need to be addressed if a hub project was to proceed, this concept presents a robust approach for the identification of scale-efficiencies. It is more coherent than the criteria proposed as part of the SENE rule change proposal [11]. Although it involves a degree of central-planning, it is ultimately a demand-driven process. AEMO is also able to consider NEM-wide implications of potential investments in the Victorian transmission network. At the current time, no transmission investments for clusters connections have been undertaken. However, the technical assessment by AEMO [18] would assist developers who are considering projects in these areas.

2.1.4 Other relevant research

A number of Australian studies have documented the challenges for connecting location-constrained renewable energy resources [2, 15, 19, 20]. The SENE concept has been investigated by Chattopadhyay [19] as well as Hasan *et al.* [2, 20]. In [19], four theoretical case studies are investigated to assess the relative merits of developing generation projects by use of the SENE regime, the RIT regime, and by a negotiated outcome between a developer and the TNSP. The potential for the staged development of the SENE is also considered. In [20], Hasan *et al.* describe a range of different transmission network configurations for new generator connections and propose the addition of an environmental component to the net benefit calculation for these projects. This net market benefit evaluation approach is expanded on in [2]. This paper also reviews a number or international and domestic schemes for connecting remote generators. Some of these are explored in more detail in section 2.3 of this report.

2.2 Market Reforms in progress

2.2.1 The Transmission Frameworks Review

Investment in transmission in the NEM has historically been driven by the need to meet demand-side reliability standards [4]. The Transmission Frameworks Review (TFR) considers whether efficiency can be enhanced by allowing generators to drive investment in transmission. For this to be achieved, generators will need to have enforceable rights to use the transmission system, thus overcoming the free rider problem. In facilitating this, the AEMC makes recommendations in regard to:

- Implementing a system of optional firm access whereby generators have the option of buying firm access rights to the transmission network
- Enhancing transparency, contestability and clarity in the connection frameworks

Under the proposed optional firm access (OFA) regime, generators would be able to purchase firm access rights to the transmission network. The capacity of firm access on offer would reflect the physical capacity of the transmission assets. In the event of network congestion where a rights holder is constrained-off by a non-firm generator, the non-firm generators would be required to pay compensation to the firm generator. The rights holder would thereby receive the same amount of revenue that they would have had they not been constrained-off. Hence the firm access rights represent a hedge against network congestion. Changes are also proposed to the framework for connecting to the transmission network. Of particular relevance are the proposed changes to the treatment of dedicated connection assets: the transmission equipment between a substation and a generator's plant. The AEMC recommends that these assets should be capable of being constructed, owned, operated, controlled and maintained by any party. However they would need to meet minimum technical standards, and would still be subject to third party access provisions. In the case of a third party seeking connection, the asset owner would need to negotiate on "reasonable terms".

In the case of a TNSP owning a dedicated connection asset, protection is provided to incumbents by the recommendation that, "the existing generator or customer [load] would not have to accept terms that disadvantage it as a result of the TNSP providing access to a third party" [4].

Furthermore, the AEMC seeks to clarify the circumstances in which a dedicated connection asset would become part of the shared network. The two "triggers" for this happening are when a DNSP connects to a dedicated connection asset, and when the shared network is being augmented and the most efficient option involves the subsumption of the dedicated connection asset.

These recommendations, if implemented, could remedy the concerns relating to the perceived complexity of the original SENE proposal, specifically the provisions around access and compensation, and around ownership of the connection asset.

The original SENE rule change proposal specified that the connection offer would, "contain an agreed power transfer capability, including compensation arrangements where a generator is constrained off below the agreed capability" [11]. This conflicts with the existing open access regime under which TNSP are obliged to facilitate connection, subject to network security and reliability requirements. Even though negotiated firm access is contemplated by clause 5.4A of the Rules, the AEMC has demonstrated that this would be unworkable under the existing arrangements [4].

It was also deemed problematic as to how the arrangements between the TNSP and generators connected to the SENE would be managed if the SENE was to be subsumed into the shared network [1]. This would seemingly be remedied by the implementations of the TFR recommendations. If OFA was implemented across the shared network, there would no longer be a conflict between the regulation of the SENE, and the regulation of the shared network that was envisaged at the time of the SENE rule consultation. Furthermore, the "triggers" proposed add clarity to the process of a dedicated connection asset becoming part of the shared network.

If a SENE was to be defined as a dedicated connection asset, then the TFR recommendations would give generators the ability to own and operate the asset, and negotiate access by third parties wishing to connect. Combined with the ability for generators to manage congestion through firm assess rights, the recommendations, if implemented, would be more accommodating to SENE projects. By giving generators more control over the factors that influence their investment, they would have more confidence in the SENE project.

While this appears to overcome the free rider problem, it is still necessary for a generator to individually fund an oversized asset, or collaborate with other generators in order to do so. Since generators would likely be in competition with each other there remain barriers to this occurring.

2.3 International comparisons

This section considers international examples of transmission policies for connecting renewable energy resources. An attempt is made to highlight the ways in which international jurisdictions have addressed the concerns raised by the AEMC and Australian stakeholders during the SENE rule change consultation. As stated, this report focuses on matters relating to the transmission network.

Work commissioned by AEMO has observed that European wind energy projects have typically been connected at the distribution level, whereas in the United States (US) projects have typically been larger and therefore connected at the transmission level [21]. This was also observed in compiling this report. As a result, three of the four jurisdictions considered in this section are from the US.

A number of studies have previously reviewed transmission initiatives for renewable energy connections. Both Schumacher et al [3] and Smith et al. [22] review United States (US) examples of state and regional transmission. Wright [15] provides an overview of initiatives in Texas and the United Kingdom (UK). This report explores some of these examples in more detail as well as others that were not considered in these studies. The jurisdictions considered in the following subsections are: Texas, California, the Mid-West Interconnected System in the US, and Ireland. A note is also made on relevant initiatives in Colorado, the European Union (EU) and the UK.

2.3.1 Texas

The Electricity Reliability Council of Texas (ERCOT) is the independent system operator for the interconnected electricity network that supplies 85% of the state's electrical load [23]. In the following paragraphs the acronym will be used to refer to the market itself, unless indicated otherwise.

Fleisher [24] documents the complex history of ERCOT's jurisdictional status; despite ERCOT being linked to an adjacent market by two asynchronous DC interconnectors, ERCOT is largely exempted from the jurisdiction of the Federal Energy Regulatory Commission (FERC). One implication of this is that the cost allocation methodology for new transmission projects in ERCOT differs from other jurisdictions in the United States. Clark [25] has conducted a comparative analysis of the cost allocation methods used by ERCOT and those used by the Midwest Independent Transmission System Operator (MISO).

In the absence of strong interconnection with neighbouring transmission networks, the integration of significant wind generation capacity has been managed locally. As such, ERCOT presents an interesting example of a central-planned approach to renewable energy integration in a competitive electricity market.

In 1999, Texas introduced a renewable portfolio standard (RPS) in the form of the Renewable Energy Mandate on competitive retailers in the state. The standard specified for 2000 MW of new renewable generation to be built by 2009. The existing capacity at the time was 880 MW [26]. Texas faced the familiar problem that the areas with the best wind resource were not well serviced by the existing high voltage infrastructure. These areas became constrained, an example being the McCarney area where the transmission system became constrained in 2001 [27]. The subsequent drop in wind development after 2001 is reflected in Figure 1.

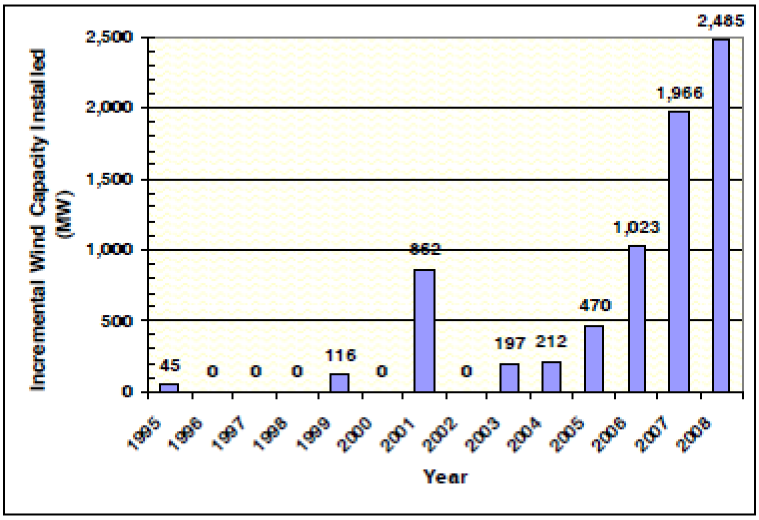

Figure 1 Incremental annual wind development in ERCOT

Source: Lasher [27]

Competitive Renewable Energy Zones

By 2005 the initial renewable energy target had been exceeded. In response to this, and to address concerns about the adequacy of the state's transmission system, the Texas Legislature introduced Senate Bill 20 (S.B 20) [26]. S.B 20 expanded the Renewable Energy Mandate to 5880 MW by 2015, and directed the Public Utility Commission of Texas (PUCT) to designate Competitive Renewable Energy Zones (CREZ) throughout the state and develop a plan to connect these zones to electricity customers [28].

S.B 20 resulted in ERCOT, the organisation, undertaking two major studies for the PUCT. These were the *Analysis of Transmission Alternatives for CREZ in Texas* (Analysis Report) and the *CREZ Transmission Optimisation Study* (CTO Study). In the Analysis Report, ERCOT requested wind developers to specify in which areas of the state they were interested in developing wind projects. The best areas were then identified using data on the wind resource and land availability; this resulted in 24 potential CREZ areas. The transmission options for connecting 10 of these areas were then studied in four discrete groups and the expected costs and benefits of each option were quantified [29]. The PUCT used these results, and considered the level of financial commitment by generators in each potential CREZ area. This was taken into account in deciding that five of the proposed regions should be designated as CREZs [30]. ERCOT was then instructed to conduct the CTO Study, a more detailed analysis of the transmission options for the CREZ that had been chosen.

The CTO Study featured four scenarios that differed in the capacity of wind that could be integrated [31]. Scenario number 2 was ultimately chosen, under which

3,824 km of new transmission lines would be built, at a cost of US$4.93 billion, to integrate an additional 11.6 GW of new wind capacity [30]. It was calculated that, based on this US$4.93 billion figure, the additional transmission costs owing to CREZ investment would add 2.2%, or US$4.04 per month, to the bill of a typical residential customer [32]. As of April 2013, the quantity of new lines required, and subsequently the cost of the projects, had increased to 5782 km and US$6.84 billion respectively. The additional costs are attributed to discrepancies between how the CTO Study envisaged the implementation of the projects, and how they were implemented in practice [33].

The PUCT allocated the CREZ projects into three categories: *Default Projects, Priority Projects,* and *Subsequent Projects*. The *Default Projects* involved modifications to existing infrastructure, and were allocated to the incumbent utilities [33]. The *Priority Projects* were deemed necessary to alleviate current and projected transmission congestion issues, and were of high priority; these were also awarded to incumbent utilities. The *Subsequent Projects* were awarded to both incumbent and non-incumbent utilities after a selection process that involved 19 entries, in which 14 were incumbents and five were not [34]. The timing of the *Subsequent Projects* would be jointly decided by the PUCT, ERCOT and the utilities [35]. Figure 2 depicts the CREZ areas and the transmission projects, colour-coded to correspond to the utility that is responsible for each project [33].

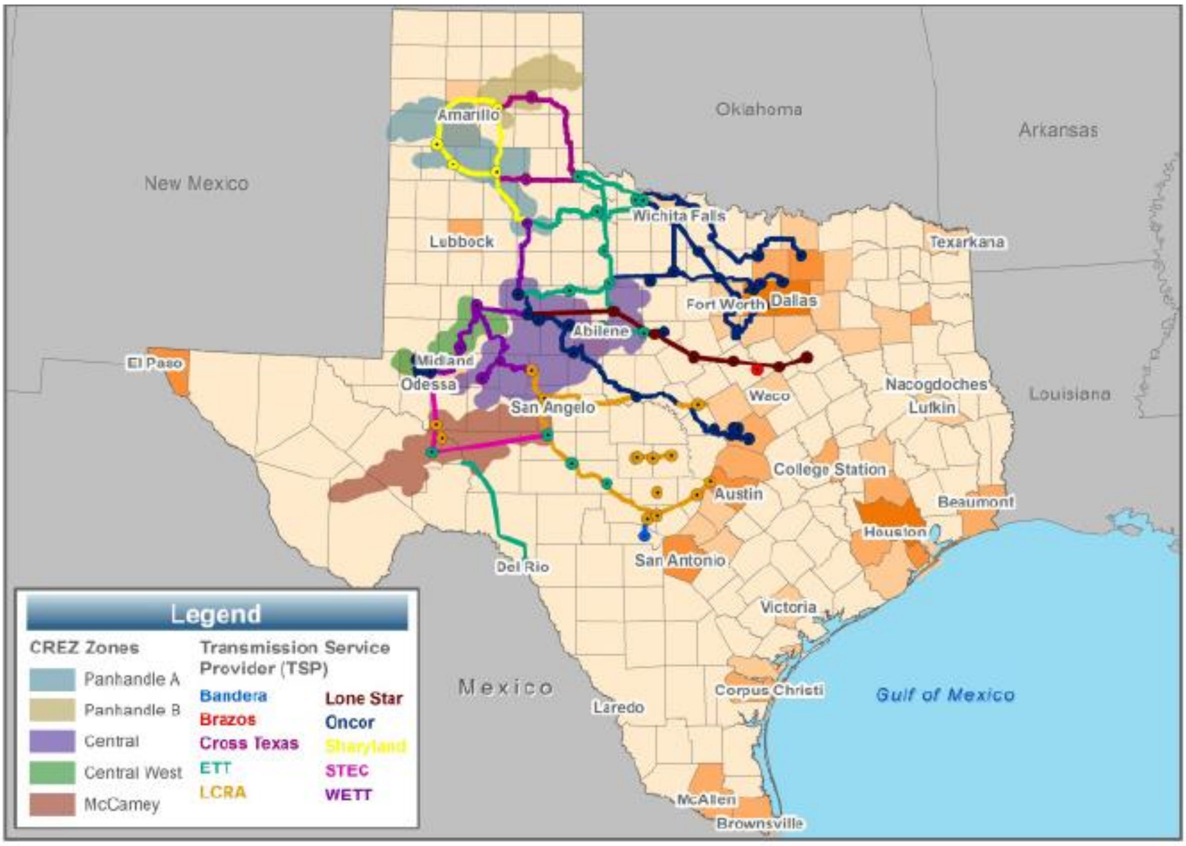

Figure 2 CREZ areas and transmission projects

The up-front costs of the CREZ transmission projects will initially be paid by the network utilities. They will then be able to recover their investment from all customers in the ERCOT market. This is represented in the Texas Utility Code [36]:

> *"If the commission issues a certificate of convenience and necessity … to facilitate meeting the goal for generating capacity from renewable energy technologies …, the commission shall find that the facilities are used and useful to the utility in providing service … and are prudent and includable in the rate base, regardless of the extent of the utility's actual use of the facilities."*

It is notable that while the ERCOT customer base is liable for the cost of the CREZ transmission projects, the PUCT is not required to consider the costs and benefits to all customers when deciding whether they should be approved [25]. Owing to ERCOT's exemption from regulation by FERC, neither ERCOT nor the PUCT are required to ensure that costs are allocated commensurate with benefits, or ensure that parties that do not benefit are not charged for the transmission investment.

Instead, the ERCOT / PUCT methodology considers the cost of the new transmission, and the expected market benefits from the new wind capacity in deciding whether the CREZ projects should proceed [25]. The PUCT concluded from the CTO Study that the investments identified under Scenario 2 are, "necessary to deliver the energy generated…in a manner that is most beneficial and cost-effective to the customers". This is supported by analysis that calculated a net energy saving of US$1.95 per MWh [32]. In making this judgement, the PUCT assumes that all rate payers will enjoy this benefit. Because ERCOT is not regulated by FERC, it is not necessary for the cost and benefit to specific customers, or for classes of customers, to be quantified.

Cancelled projects

The CTO Study initially estimated that there would be 109 CREZ projects. As of July 2013 this has increased to 186, of which 106 have been completed, 65 are 'active' and 15 have been cancelled [37]. Of the cancelled projects listed in the July 2013 Project Update, one was cancelled because the existing line was deemed capable of carrying the energy required, while another only had distribution costs associated with it and should not have been reported. A further six projects relate to the proposed Gillespie to Newtown line. The suspension of this project was announced in June 2010 and ERCOT was requested to reassess the necessity of the project [38]. In 2012, a state politician advocated that the line be suspended until the future of the federal tax credit for wind energy was known [39].

As the PUCT is required to issue a certificate of convenience and necessity for a project to process to construction, there is the potential for the necessity of a project to be reassessed, and the implementation date amended, if conditions change. This acts a protection measure against making unnecessary investments.

2.3.2 California

Key points

California has a range of mechanisms for renewable energy integration to meet the state's 33% by 2020 RPS. These include:

- The Renewable Energy Transmission Initiative (RETI), a policy-drive exercise in central planning with extensive stakeholder involvement. The initiative formulated a conceptual plan of the likely transmission investments necessary to meet the 33% Renewable Portfolio Standard (RPS). These were used as an input to on-going planning processes (in contract to the Texas CREZ approach in which the conceptual plan was implemented straight away).
- A transition from assessing interconnection requests individually to a group processing approach
- The Location Constrained Resource Interconnection (LCRI) mechanism that allows for the oversizing of transmission assets when it is expected that more generation projects will be developed in the same area

The conceptual plan produced through the RETI, and progressed by the California Transmission Planning Group (CTPG), represents the ideal future. Market participants can then use this information in the planning of transmission and generation investments. The interconnection studies allow for the identification of potential scale-efficiencies from connecting generators in a cluster rather than individually, while the LCRI provides a financial arrangement for this to occur.

California is the most populous US state and ranked number two in terms of total electricity retail sales [40]. As part of the Western Electricity Coordination Council (WECC), the Californian grid is connected to all bordering states, including part of Mexico [41]. The Californian Independent System Operator (CAISO) is the system operator and planning body for 80% of the state [42]. Regulatory functions are performed by the Californian Public Utilities Commission (CPUC), the California Energy Commission (CEC), and federal regulatory bodies.

The state has a Renewable Portfolio Standard (RPS) for electricity of 33% by 2020. In 2012, the three largest load-serving entities served 19.8% of their retail sales with renewable energy [43]. In meeting the 33% target, market stakeholders have implemented a range of initiatives that promote the integration of renewable energy. One of these has been the Renewable Energy Transmission Initiative (RETI), as documented by Olsen et al. [44] and the California Energy Commission [45].

Price and Sheffin [46] summarise a number of market and operational initiatives of the CAISO in facilitating the integration of renewable energy resources. Further, an overview of current transmission planning practices is provided by Zhang et al. [47]. The latter proposes an integrated transmission planning framework for renewable energy integration. The authors of sources [46] and [47] consist primarily of current and former employees of the CAISO.

The following sub-sections document three specific transmission initiatives for renewable energy integration: the RETI, the CAISO's processes for generation interconnection, and the Location Constrained Resource Interconnection (LCRI) mechanism.

Renewable Energy Transmission Initiative

Launched in 2007, the RETI was a stakeholder-led planning process that developed a conceptual plan for transmission network expansion to meet the 33% RPS. This occurred in two phases: the identification and ranking of renewable energy zones, and the determination of required transmission investments by use of a least-regrets planning approach.

The primary differences between the RETI and the ERCOT study in Texas in terms of CREZ area identification were that:

- The potential Californian CREZ zones were ranked in terms of economic performance and environmental impact. The environmental impacts of CREZ developments were a key factor in the selection process.
- The identification criteria were specified by a steering committee that included a broader cross-section of stakeholders. Utilities, renewable energy project developers, local, state and federal permitting agencies, the military, tribes, consumers, and environmental groups were all represented.
- CREZ zones from outside of California were considered

Eight environmental criteria were used in the assessment: Energy Development Footprint, Transmission Footprint, Sensitive Areas in CREZ, Sensitive Areas in CREZ Buffer Areas, Significant Species, Wildlife Corridors, Important Bird Areas, and Land Degradation [48].

The most attractive CREZ areas for California were those with relatively less negative environmental impact, and relatively low economic cost; 35 were identified in total [44].

In assessing the transmission investments required, a range of scenarios for connecting the CREZ areas were considered, resulting in a list of possible, new transmission components. Each component was assessed in terms on four metrics: an energy score based on GWh of energy delivered, an economic value score, an environmental impact score, and a ranking that assessed the known commercial interest in the CREZ area. These metrics were then scaled by a shift factor that represented the relative usefulness of the component in the access to and delivery of renewable energy. These scaled metrics were then summed together to yield a single 'Combined CREZ Energy Score' for each potential transmission component. These scores were used in a least-regrets planning analysis to identify the transmission investments most likely to be 'used and useful'. These investments became part of the conceptual plan.

This was the first time that a shift factor for renewable energy flows was used for this application. The significance of this is that it is expected that stakeholders and the public will be more supportive of new transmission lines if their primary purpose is to access renewable energy resources [44]. The methodology allows for this contribution to be estimated. Benefits are anticipated to come from reduced litigation costs and less delays during the permitting process for transmission [49].

A further difference between the RETI and the CREZ process in Texas was that the PUCT in Texas went straight from conceptual plan (the CTO Study) to implementation, whereas the conceptual plan and methodology developed through the RETI in California was used as an input for on-going planning initiatives. The RETI was suspended in 2010 as the newly formed California Transmission Planning Group (CTPG) took responsibility for the coordination of state-wide planning [44]. Consisting of transmission owners and operators, the purpose of the CTPG is to develop a state-wide transmission plan that identifies the transmission infrastructure needed to reliably and efficiently meet the RPS target [50]. The CTPG use the results of the RETI in this process.

The CAISO is a non-member participant in the CTPG and uses the conceptual plan as part of its own transmission planning process. The CAISO originally proposed a separate Renewable Energy Transmission Planning Process (RETPP), however the changes were later added to its pre-existing annual transmission plan [51]. In this plan, transmission investments to meet the RPS are considered before those for reliability and alleviating network congestion [52]. The CTPG ensures consistency between CAISO's planning process and those of the other transmission owners and operators.

Interconnection process reform

As an initiative separate from the RETI, in 2008 the CAISO implemented the Generation Interconnection Process Reform (GIPR) which applied to projects greater than 20 MW. The major elements of this reform were a shift from assessing interconnection requests on a case by case basis to a cluster study approach, and new cost allocation methodologies for network upgrades [53]. The package also established financial obligations for applicants to discourage speculative projects. However, these were revised in 2009, in part due to the economic downturn [46].

The GIPR process resulted in amendments to Appendix Y of the CAISO Tariff [54]. This document contains the terms and conditions, as approved by FERC, by which the CAISO operates. Further amendments to Appendix Y, entitled Generator Interconnection Procedures (GIP), are proposed through the GIP Phase 2 reforms that were filled in January 2012 and are currently pending approval by FERC [55].

Location Constrained Resource Interconnection

In 2007, FERC approved a proposed change to the CAISO Tariff to introduce a new financing mechanism that would allow Location Constrained Resource Interconnections (LCRI) [56]. This initiative pre-dated the RETI. The LCRI mechanism is very similar to the proposed SENE rule change for the NEM. Essentially, a transmission asset, designed to connect a location-constrained resource, can be oversized when there is the expectation that more generation will be developed in the same area. This is facilitated by a new category of transmission project that is eligible for an alternative cost-allocation mechanism.

Originally projects were either funded through the regulated revenue requirement of the network utility, or by the generator. Under the new mechanism, unsubscribed capacity on an oversized asset is added to the revenue requirement of the network utility until generators connect. Future generators will pay on a per MW basis for access to the transmission line, with revenue credited against the charges initially recovered through the regulated asset base [57]. This new mechanism for cost-allocation was the primary difference between the proposal and the pre-existing regime [58]. These mechanisms are summarised in Table 3.

Table 3 Transmission project categories and cost allocation in California

Transmission category	Status at time of LCRI proposal	Cost allocation
Network Facility	Existing	Reliability or economic rationale. Costs are rolled into Transmission Access Charge (TAC).
Generator Tie-lines	Existing	Generator pays up-front before interconnection.
Location Constrained Resource Interconnection (LCRI)	Proposed	Costs initially rolled into TAC; generators reimburse their share when they connect.

There are two specifications in the LCRI policy that protect consumers against the risk of assets becoming stranded. These are a minimum level of firm and near-firm commitment by developers and a cap on the total investment that can be made on LCRI projects. The CAISO requires for a LCRI project to proceed that 25% of the transmission line must be subscribed, and there must be additional developer interest representing a further 35% of the line [57]. This interest can be expressed as a signed power purchase agreement of at least 5 years, or a 5% deposit on the desired capacity [52]. Further, the total investment in LCRI projects that can be included in the revenue requirement to be recovered from customers cannot exceed 15% of the entire transmission asset base. For California, this implied a maximum increase of 16.04% in the regulated revenue of the network companies [57].

The scheme is similar to the SENE proposal in that it does not favour one generation technology over another, other than that the fuel source must be location-constrained. This is justified as the policy is, ‘designed to address a market failure that imposes barriers to the efficient development of renewable generation facilities' [58]. The CAISO believes that the policy will allow for state and local RPS and fuel diversity goals to be met at a lower cost than if it were not implemented.

The LCRI policy does not address how access rights are maintained (i.e. how generation capacity in excess of the LCRI transmission asset capacity would be managed). However, CAISO operates a Congestion Revenue Rights scheme that facilitates financial transmission rights [59]. The scheme has operated since 2000 but changed from a 'flowgate' system to a point-to-point scheme in 2009 (see [60] for more details). If the LCRI asset becomes a 'network facility' then generators would no longer be required to pay for using the asset [61].

In assessing a LCRI project proposal, the CAISO considers the following [57]:

i. Maximum potential capacity for location-constrained generation (obtained from the State regulatory agencies);
ii. Maximum potential energy for meeting the State RPS goals;
iii. Various transmission alternatives to determine the most cost-effective transmission plan;
iv. Total capacity of generation projects in the CAISO generation queue for each of the Energy Resource Areas (ERA);
v. Fuel diversity (as an example, an ERA for wind energy is selected in conjunction with either geothermal and/or solar energy to provide fuel diversity portfolio);
vi. Distance to the nearest possible CAISO transmission bulk facility (for connection to the CAISO controlled grid);
vii. Potential viable transmission route;
viii. Order of magnitude of transmission cost per MW for the Location Constrained Resource Interconnection Facilities (LCRIFs) to deliver energy to the load centers;
ix. Realistic commercial operating dates for location-constrained projects and the transmission LCRIFs;
x. Potential impact on the Transmission Access Charge (TAC);
xi. Potential operational/congestion/reliability benefits of the facility;
xii. Stranded cost risk and potential impact if stranding was to occur.

The CAISO's 2011-12 Transmission Plan considers two LCRI proposals [52]. One of these is accepted by the CAISO as meeting the criteria for LCRI project approval while the second one is not accepted. The investment associated with the accepted project equates to 0.57% of the transmission revenue requirement, and 65% of the lines capacity is accounted for by an executed connection agreement and additional connection requests. Hence the two consumer protection measures are satisfied. There are no new LCRI projects in the 2012-13 Transmission Plan [62]. This could be because the policy-driven criterion for new transmission was introduced into the CAISO Transmission Plan after the LCRI. Investments deemed necessary to meet the 33% RPS are funded by the customer base. If a project was eligible for both the LCRI (generator pays) and approval as a policy-driven investment (customers pay), the latter option would be more attractive to the proponent.

2.3.3 Mid-West Interconnected System

The Mid-West Independent Transmission System Operator (MISO), like the Californian ISO, is a Regional Transmission Operator (RTO) and Independent System Operator (ISO). It conducts market operation and planning functions for a power system that spans 11 states and has a historical peak load of 98.6 GW [63].

In its transmission expansion planning role, MISO has developed a portfolio of Multi Value Projects (MVP). These MVP projects are transmission investments that are expected to provide multiple kinds of reliability and economic benefits under a range of potential future scenarios. They were designed to allow the states in the MISO region to meet their RPS policy targets (Figure 3), while also creating reliability and economic benefits.

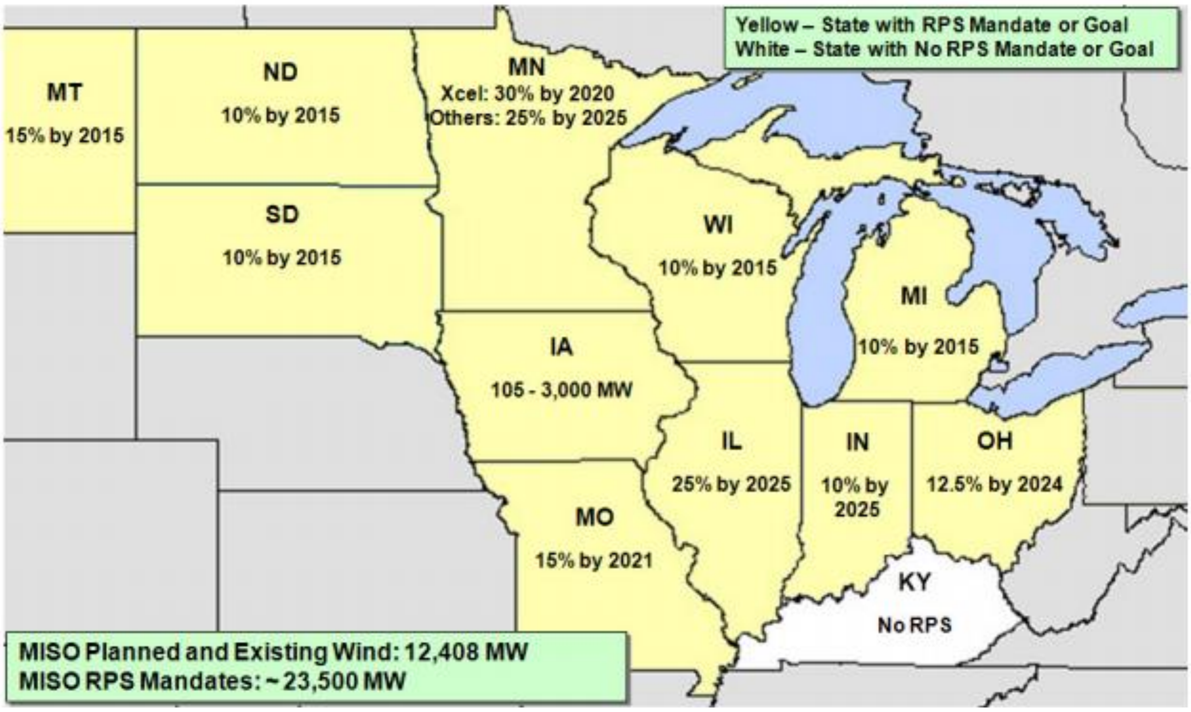

Figure 3 Renewable energy mandates in the MISO region

Source: Mid-West Interconnected System Operator [64]

In meeting the state-based RPS targets, it is acknowledged that a regional approach is required to do this at the lowest overall cost. The MVP approach is interesting in the way it combines the different motivations for transmission investment. MISO [64] describes its planning process as:

> *"…a comprehensive expansion plan that reflects a fully integrated view of project value inclusive of reliability, market efficiency, public policy and other value drivers across all planning horizons."*

The MVP Portfolio Analysis Report of 2012 [64] identified 17 transmission projects across the MISO area for implementation between 2014 and 2020 at a present day cost of US$5.2 billion. The portfolio was assessed as having a cost to benefit ratio of between 1.8 and 3.0 over the planning time frame. It would resolve anticipated reliability violations while enabling 41 TWh of wind energy per year. In doing so the portfolio would create average annual value of almost US$1.3 billion over the first 40 years of operation, at an average annual cost of US$624 million.

While the MVP portfolio does not solely cater for renewable energy interconnection, it does recognise and assess the trade-offs between wind resource quality and transmission investment required to access that resource. The MVP projects differ from the Australian SENE concept in that although the renewable resources considered by the MISO are, in some cases, remote, the network investments required to 'unlock' them are new transmission lines between two existing nodes, rather than an extension into a remote area. A similar situation in the Australian NEM was suggested by the *Isalink* and *CuString* projects that proposed the construction of high voltage power lines between coastal and inland Queensland [65, 66]. The north Queensland grid is relatively weak and would require substantial upgrades to access renewable energy projects in this part of the country.

The MVP analysis methodology emphasises the necessity of adapting the existing network to new energy flows, not just network extensions that access 'stranded' resources.

As an example of how renewable energy public policy goals have been included in transmission network planning, the MVP methodology is interesting for a number of reasons:

- It simultaneously considers public policy, reliability requirements and economic drivers for transmission investment, allowing for transmission investments to be justified based on the multiple types of value that they create.
- It maintains flexibility by supporting a variety of future generation priorities, including gas. It also supports the expansion of the state-based renewable energy targets in the future.
- It considers qualitative and social benefits that were not fully quantified through the MISO's traditional economic and reliability assessments. These are: generation policy flexibility; enhanced system robustness; decreased natural gas risk; decreased wind volatility; local investment and job creation; and, carbon emissions reduction.

2.3.4 *Ireland*

The Republic of Ireland and Northern Ireland are interconnected by the All Island Grid (AIG). This allows for the operation of one electricity market across the two jurisdictions: the Single Electricity Market (SEM). The utility Eirgird is both the TNSP and the system operator for the SEM through its subsidiaries System Operator Northern Island (SONI) and Single Electricity Market Operator (SEMO). Eirgrid also owns and operates the East West Interconnector, a 500 MW HVDC link between Ireland and Britain [67]. The other link between Ireland and the EU grid is the 500 MW Moyle Interconnector between Northern Island and Scotland [68]. These interconnectors and transmission lines of 220kV and above are shown in Figure 4.

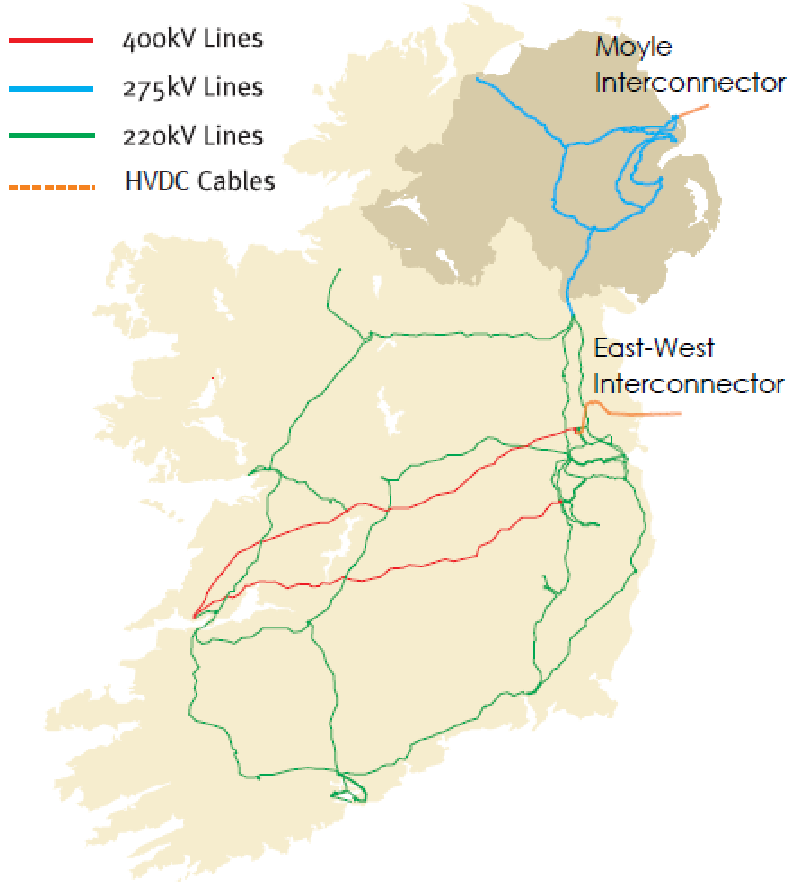

Figure 4 Ireland transmission network (220kV and above) and interconnectors
Source: Eirgrid All-Island Transmission Map [69] (edited)

The installed capacity of wind energy in Ireland has grown from less than 200 MW in 2002 to be almost 2500 MW in 2012 [70, 71]. This is large in comparison to the peak demand of the AIG: approximately 6500 MW in winter and 4500 MW in summer [67]. As a result, wind energy supplied 17% of electricity demand in 2011 [71].

The SEM operates under an open access regime whereby network operators provide non-discriminatory network access to generators [70]. Wind farms that connect are liable for the 'shallow' costs of connecting to the transmission network, but not the 'deep' costs of additional network reinforcement.

Renewable energy policies

Ireland has a renewable energy target for electricity of 40% by 2020 [72]; wind energy will be pivotal in reaching this contribution [73]. Foley et al. [74] have documented the support mechanisms for wind energy in the SEM. These are the Alternative Energy Requirement scheme, whereby over 500 MW of wind was offered power purchase agreements via competitive tender; the Renewable Energy Feed-in Tariff (REFIT); and, a renewable obligation scheme for electricity suppliers in Northern Ireland. The REFIT scheme is the primary means by which renewable energy sources are supported in Ireland. The value of the payment to large wind generators in 2013 is €69.235 per MWh (or $98.66 Australian dollars[1]) [75].

These mechanisms have supported wind development since the early 1990s; however it was in the early 2000s that significant increases in the amount of wind capacity were observed (see Figure 5). A lack of technical standards for connections or adequate models to evaluate system impacts led to a moratorium on new wind connections in late 2003 [70, 76]. This decision would ultimately result in the development of the Group Processing Approach (GPA) for generator connections.

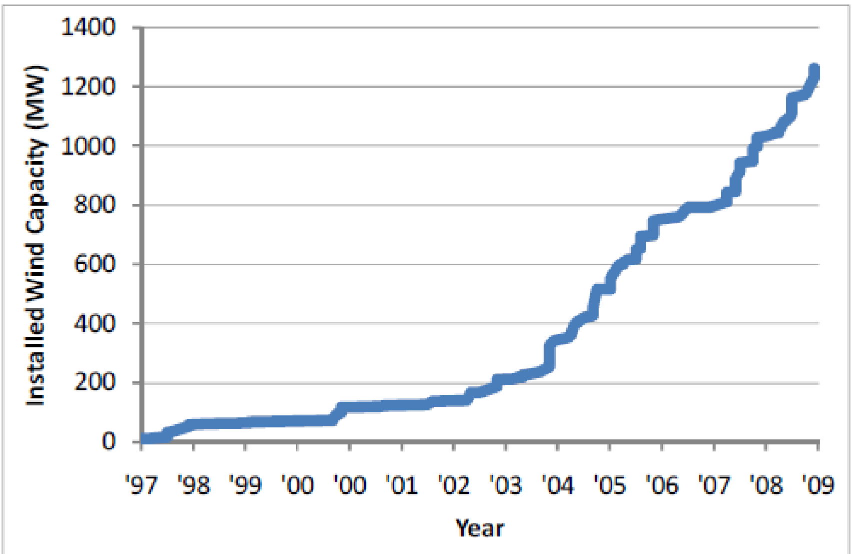

Figure 5 Installed capacity of wind energy in Ireland between 1997 and 2009

Source: Smith et al. [70]

Prior to the 2003 moratorium, generator connection applications were processed individually. This meant that when a connection offer was accepted, any remaining connection applications that interacted with this offer would need to be reassessed [77]. The large number of applications that were received during the moratorium highlighted the need for a more coordinated approach. Hence when the moratorium was lifted in 2004, the GPA was introduced. Applications where processed simultaneously in batches, or 'Gates', where the eligibility criteria and size

[1] At an exchange rate of 1 Euro = 1.42494 Australian dollars

of the gate was determined by the regulator [77, 78]. The applications are divided into groups and assigned a connection node on the transmission or distribution system [70]. This allows for the development of connection clusters that have similar characteristics to a SENE.

There have been three Gates since the GPA was first introduced. Through Gates 1 and 2, connection offers were accepted by 362 MW and 1334 MW of new wind capacity [77]. Gate 3 saw connection offers made to approximately 4000 MW of new wind capacity, and 2000 MW of conventional generation capacity. Gate 3 has been extensively analysed by Leahy [77]; since it is the most recent version of the GPA it will be the focus of the rest of this section.

Gate 3

The Gate 1 and 2 developments required significant reinforcement to the main transmission system. Hence it was decided that the capacity for the new connections under Gate 3 would be allocated as it becomes available according to the long-term transmission grid development strategy, Grid25 [70]. The strategy takes account of system demand forecasts, renewable energy targets, forecast conventional generation developments, and future interconnectors.

Smith et al. [70] summarise the processing method for applications that were chosen for Gate 3, based on date order, as being necessary to meet the 40% by 2020 renewable energy target:

1. Applicants are assigned to an existing or new node on the transmission or distribution network. Clusters develop where multiple applicants are assigned to the same node.
2. The network operators develop a 'least cost, technically acceptable' method by which the node and / or applicants can be connected to the network.
3. Based on the transmission investments planned through Grid25, applicants are allocated a Firm Access Quantity for each year from 2010 until 2025. In some cases this allocation is zero for the initial years.

This information, in conjunction with the costs of the shallow connection, is provided to the applicant before they accept a connection offer [77].

In the analysis conducted by Leahy [77], Gate 3 was deemed to be a fair and transparent process that would reduce the shallow connection costs borne by generators. However, by prioritising projects based on their date of application, the approach did not result in timely connection or the optimum development of the network. In addressing these criticisms, it was recommended that future gates be smaller but more frequent, and that system optimisation should be considered as well as the date order in which applications were made.

Eligibility criteria and project completion rate

Ireland's experience with renewable energy connections is fundamentally different to the experience in Australia to date. The GPA resulted from a surplus of connection requests (stimulated by generous incentives) and a desire to address the applications in a coordinated manner. In some cases, network extensions were proposed that have similar characteristics to a SENE, especially under Gate 3 where the connection dates vary depending upon when firm access has been allocated.

As the GPA has operated for a number of years already, it is possible to assess the results so far. Two key areas relating to concerns raised during the SENE rule change process in Australia will be considered in more detail:

- The assurances required from developers to mitigate the stranded asset risk to the network company and consumers.
- The percentage of projects included in the Gate progresses that have not gone ahead.

In specifying uniform eligibility criteria for consideration in each Gate round, there is the potential to set conditions that dissuade speculative applications, thus reducing the chance of transmission assets becoming stranded if the generation project does not proceed. A condition could be that the developer must have secured consent from the landholders affected or received planning approval. Despite this opportunity, the Commission for Energy Regulation did not take this approach. In fact, Leahy [77] observed that in Ireland the first step in the development process was the connection application, even before a feasibility study had been conducted. This contrasts with wind farm project development in Australia where the grid connection application typically occurs towards the end of the process, after a feasibility study, resource assessment, and planning approval [79]. It is likely that the deadlines associated with the Gate rounds encouraged many early stage projects to apply so that they would not miss out.

The first real test of the level of commitment of the Gate 3 participants only came when the connection offer is accepted. At this point the developer must make the First Stage Payment. This payment is between 10 and 50% of the total connection costs: "the greater of 10% of connection costs or the lesser of €10k/MW and 50% of the connection cost" [80]. Applicants in sub-groups with shared assets pay on a per MW basis according to the firm access they will receive [77]. The balance of the connection costs is due in instalments. When Gate 3 was first announced, developers were required to post a €10,000/MW bond at the time of the connection offer being accepted [81]. However, this was later changed to a bond of €25,000/MW to be put in place one month prior to 'energisation' [82]. This is defined as the point when a generator is electrically connected to the network, but is not allowed to export.

Both the First Stage Payment and the capacity bond specify a financial commitment from developers, hence reducing the risk to the network operator that assets could be stranded or underutilised. However, there were still concerns that some applicants might only be seeking to secure the connection rights so they can sell them to developers who had missed out [77]. Leahy recommended a criterion that assesses the preparedness of the applicant to avoid this occurrence.

The second area of interest is whether or not projects considered in the Gate processes have gone ahead. Gates 1 and 2 were finalised in December 2004 and June 2006 respectively, and the Eirgrid website notes that: "Most of the Gate 1 and Gate 2 projects are now either connected to the grid or in the construction stage" [83]. Under Gate 1, 373 MW of connection offers were made; as of November 2012, Eirgrid data [84] shows that 265 MW had connected, and a further 84 MW was listed as contracted. This suggests that 8 years after the connection offers were accepted, only 6% of wind capacity with a connection offer had not been constructed or contracted. Over 70% had been constructed. For Gate 2 projects, 647 MW of the initial 1334 MW of accepted offers had been constructed, while a further 700 MW had been contracted. This suggests that the Gate 2 capacity originally accepted is scheduled to be exceeded. Seven years after Gate 2 was finalised, 50% of the accepted offers had been constructed.

From these figures, there is a high up-take of the Gates 1 and 2 connection offers. However, it is notable that there was variation in the amount of time between a connection offer being issued and the generator connecting. This time period has been estimated for the Gate 1 and Gate 2 projects that have been connected based on the expected processing time and acceptance window specified in by the regulator [78, 85]. The results of this analysis are shown in Figure 6. The mean time gaps between offer acceptance and connection for Gates 1 and 2 were 3.3 and 3.4 years respectively. For Gate 1 this represents a connection in 2008 for projects that originally applied for connection in 2003, and, for the purposes of the Gate 1 analysis by Eirgrid, were assumed to connect in 2005 [78]. This appears to be a sizable delay; however, without knowing the specific circumstances of each project, it is not possible to tell if this delay was unintended and led to inefficient network investment, or if it was in fact caused by a delay on the part of the network utility.

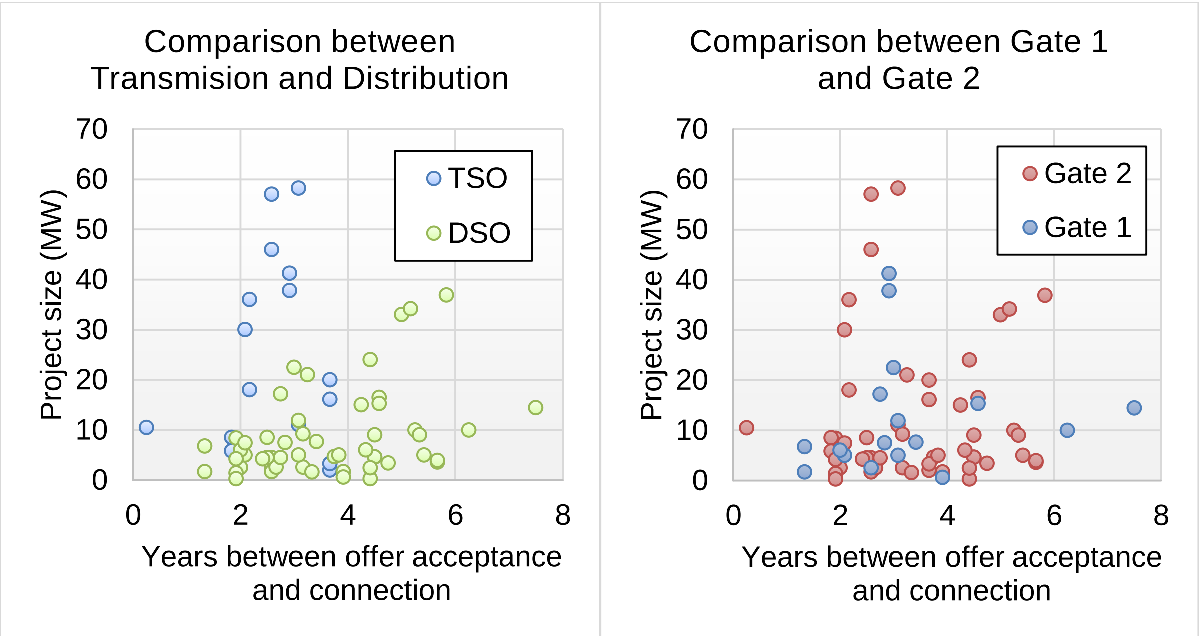

Figure 6 Time period between acceptance of connection offer and connection to network

There was a difference between the time gap between offer acceptance and connection for transmission and distribution connections. The average gaps were 2.7 and 3.6 years respectively. This implies that projects connecting to the distribution network took on average one year longer to connect than projects connecting to the transmission network. However, the sample size for the transmission projects is smaller than that for the distribution projects: 17 compared to 53. Most of the connections to the distribution network were for projects of less than 10 MW. Clusters could be considered for combined connection capacities of more than 40 MW [70].

Again, without knowledge about the specific projects, it is difficult to make firm observations of whether these time gaps led to inefficient investment. However, the variation highlights the difficulty in coordinating network investment with the timeframes of generation projects. The data shows instances of multiple generators connecting to the same node with time gaps of multiple years between connections. This occurred more at the distribution level than for transmission connections. In the case of a new node being constructed for a cluster, there is the potential for a stranded asset, or underutilised capacity. However, this risk was reduced by the requirement of a €10,000 per MW bond at the time of connection offer acceptance. It is unknown how this figure compares to the total cost of the transmission assets as this cost would depend on the line length, as well as transmission capacity and other factors.

Summary

The GPA process in Ireland has developed such that the network capacity offered through the most recent round is coordinated with the long-term network development strategy, Grid25. One of the considerations of this strategy is how the 40% by 2020 renewable energy target will be met. The Gate rounds have allocated network capacity to almost 6 GW of renewable energy projects. However, by not assessing the preparedness of applicants, connections have not always occurred in a timely manner. A combination of an initial payment and a bond payable by the developer reduced some of the risk for the network operators, but there were still large variations in the time between a connection offer being accepted, and the generator connecting. The analysis of the data for Gates 1 and 2 of the GPA shows that 53% of the projects have connected within 2 to 6 years of offer acceptance. Further investigation on the experience with clusters under the GPA may be of value. Generation clusters in Ireland have been discussed on a theoretical level by Smith et al [70] and the Commission for Energy Regulation [85].

2.3.5 Other examples

A number of other international policies for connecting remote renewables have been identified. These are:

- In Colorado, Senate Bills 07-091 and 07-100 call for the identification of Energy Resource Zones where transmission constraints hinder access to renewable energy resources [3]. Utilities are required to develop plans for the expansion of the transmission network to access these resources. There are currently nine transmission projects under consideration [86]. This approach is similar to the CREZ approach in Texas.
- The European Union OffshoreGrid project investigated design options for offshore wind farm connection, including: wind farm hubs connected by a single transmission line; connecting wind farms to existing or planned transmission lines; and, connecting wind farm hubs to form international interconnectors [87].
- In the United Kingdom (UK), network policy has been informed by the work of the Electricity Networks Strategy Group [88]. The UK has implemented a range of policies that concern renewable energy connections, including the Connect and Manage regime, Project TransmiT, and a framework for offshore transmission network development [89]. Ofgem's new RIIO model for transmission regulation is designed to be more accommodating to low-carbon technologies [15, 90].

2.4 Key learnings for Australia

The international examples reviewed in this report do not indicate a single best approach to remote renewable energy integration but they do provide a range of interesting insights. One the main concerns raised during the SENE rule change process was that consumers were not adequately protected against the risk that oversized transmission assets could become stranded. International practices, particularly the LCRI mechanism in California, demonstrate how this protection can be improved.

The research also suggests that a conceptual plan for renewable energy integration allows for the identification of scale efficiencies, thereby promoting efficient network expansion. Such an exercise benefits from a high level of stakeholder input as well as clear and certain targets for renewable energy deployment.

Transmission planning tasks are made simpler by circumstances that limit the relevant technologies for consideration. Internationally there are different ways in which renewable energy goals have been integrated into network planning process. An option for the NEM could be for renewable energy network extension to be given the same status as reliability-based investments in not having to demonstrate a net market benefit. These topics are discussed in more detail in the following sections.

2.4.1 Risk can be reduced through financial assurances

A criticism of the original SENE proposal by the MCE was that it did not provide adequate provisions to protect consumers against the risk of stranded assets. The elements proposed to protect against this risk were that at least one generator would have to commit to connect, stakeholders would be able to comment on the size of the project, AEMO could check the forecasts used in the modelling, and the AER would maintain the right to veto the project [10]. Based on the international examples considered in this report, this could be improved by:

- Specifying both firm and near-firm capacity commitments from project developers intending to connect to the SENE; and
- Implementing an absolute or relative (per cent) cap on the amount of money that could be invested by TNSPs in SENE projects.

A capacity threshold was considered during the SENE rule change process: the first and second options in the Options Paper specified a 25% firm commitment, while stakeholders suggested values between 25 and 60% [14]. The AEMC did not make a recommendation on a capacity threshold, instead noting the risks of setting the threshold to high or too low:

> *"Any proportion will essentially be arbitrary…setting the level too low will not significantly contribute to minimising the asset stranding risk…[while] setting the threshold level too high risks the SENE never materialising".*

The Californian LCRI mechanism specifies the equivalent of the 25% firm commitment, as well as a further 35% as having signed a PPA or paid a deposit. This means that for an investment to be approved, 60% of the project is backed by a firm or near-firm commitment. While there is still risk under this arrangement, the 60% commitment is more robust than 25% and the split between firm and near-firm commitment is more accommodating to projects at different stages of the development process.

Deposits and bonds are required from developers in Ireland to accept a connection offer and for a network asset to be built. As the connection costs are paid in instalments, it seems unlikely that a transmission asset would be built without the generator having paid most, if not all, of the total amount. While this reduces the risk of stranded assets, it has not led to timely connections. This approach would work most effectively for staged network extensions where the early payments from the generators connecting at the end of the extension could underwrite the over-sizing of the initial stages of the line.

2.4.2 Conceptual plan for renewable energy integration

A planning exercise that has been valuable in the international cases reviewed in this report is the conceptual plan for renewable energy integration. This captures developer demand for transmission expansion, and public policy, in a system-wide optimisation of future network requirements. The plan can then be implemented immediately (e.g. Texas), or used in pre-existing planning initiatives (e.g. California); the latter approach is likely to be most compatible with the existing NEM frameworks.

The benefits to California were that the conceptual plan provided a uniform set of inputs for individual TNSPs, and that the new transmission projects are expected to be less controversial as the process involved a high degree of stakeholder involvement. Reduced litigation costs and permitting delays were anticipated as a result. Further, the RETI used a “shift factor” to demonstrate how much renewable energy the new transmission lines would transport. It was expected that there would be more public support for transmission lines to transport renewable energy than for other transmission investments.

In the NEM, a conceptual plan would establish, through stakeholder consultation, a consensus view as what renewable energy sources are likely to be developed and the transmission investments required to meet public policy targets. The results of this conceptual plan could then be used as inputs to the NTNDP and other planning processes. This could be modelled on the work of the RETI and CTPG initiatives in California and build on the work already done by AEMO through the 100 per cent renewables modelling study [91].

A conceptual plan would be particularly valuable for a post-2020 renewable energy target. It is expected that SENEs will be required if the RET is expanded to be greater than 20% [92]. In the case of this happening, a NEM-wide conceptual plan for renewable energy could be an effective method of identifying potential scale efficiencies, allowing for renewable energy projects to be integrated in the most efficient manner.

2.4.3 Stakeholder involvement

The AEMC notes that planning work for SENEs by AEMO or TNSPs "prior to tangible market interest being demonstrated… [could be]…potentially superfluous" [14]. This emphasizes the need for transmission planning, and in particular the conceptual plan, to have strong stakeholder participation to limit the assumptions and estimations that need to be made by the planning body.

The involvement of stakeholders also acts as a risk reduction mechanism. Renewable energy zone initiatives in California and Texas reduced the risk of stranded assets by soliciting expressions of interest from project developers at an early stage. By involving these stakeholders at the beginning, planning efforts were focused on the most applicable regions so that stranded assets and superfluous planning were less likely to occur.

While this consultation may have also occurred in the NEM had the initial SENE gone ahead, it was not explicitly mentioned in the proposal [11]. Instead, AEMO was to consider:

i. the likelihood of the development of more than one electricity *generation* project in the relevant area; and
ii. any proposed development of the *national grid* contemplated in the current NTNDP.

Because the NTNDP only takes into account generation projects that are committed, it is not possible to capture developer interest that is contingent on a generation cluster connected by a SENE (options to address this are discussed in Box 2.1). Committed projects are an input from the Electricity Statement of Opportunities (ESOO), in which they are defined as projects where land acquisition, supply contacts, environmental approvals and financing arrangements have all been finalised [93]. For this reason, only a small number of the projects noted in the ESOO appear in the NTNDP.

Considering this, a conceptual plan including developer interest and projects contingent on scale-efficient connections could complement existing planning processes.

Box 2.1 Capturing developer interest through the NTNDP

The NTNDP could be modified to capture developer interest that is contingent on a generation cluster and a SENE:

- By including the generation projects from the ESOO that have been publically announced but are not yet classified as committed; or
- By modeling the option for a SENE in the long-term forecast

The first of these options is problematic because the publically announced projects can be highly speculative and may not have a high chance of proceeding.

Developers may overstate the nameplate capacity of the projects. Also, the projects are unlikely to be mutually exclusive and in some cases will be in competition with each other. Analysis by AGL indicates that to meet the 41,000 GWh RET, 90% of the known wind energy projects would need to be developed [94].

For the second option to occur, a generation cluster could be modelled as a single new entrant, or as multiple new-entrants representing staged investments. The characteristics of the new entrant could represent the combined characteristics of the generators in the cluster. Another option is for the projected costs for new-entrant generators to be discounted if, at the discounted rate, it is economical for multiple generators to connect in a similar time period. This would account for the scale efficiencies possible through the SENE development.

2.4.4 Clear and certain renewable energy targets

Compared to international examples, there is potentially more uncertainty in Australia in terms of policy and technologies. This makes it harder to anticipate which renewable energy projects will eventuate in the future. For SENEs, these uncertainties increase the perception that transmission assets may become stranded by generators not wanting to connect to them.

In Australia, the RET is the key driver for new investment in renewable energy in Australia. However, because its growth ends in 2020 it is not applicable for forecasting generation and transmission investments in the decades after 2020. Furthermore, the two year review period for the RET means that there is the potential for key design features to be changed at short notice. Hence there is uncertainty regarding both the 2020 target and what might occur after this point.

Scale efficiencies are more likely to be realised when there is a clear and certain trajectory for renewable development over the long term (beyond 2020). Further, having a target simplifies the process of forming a conceptual plan for renewable energy transmission expansion by reducing the number of assumptions that need to be made. For these reasons, a long-term renewable energy target supported by a strong policy mechanism that is not subject to ad hoc changes will likely promote scale-efficient network expansion for renewables.

2.4.5 Technology clarity simplifies network planning

In the period post-2020 it is expected that more renewable energy technologies will become economically viable. Solar thermal, geothermal, tidal and biomass are potential candidates. The SENE rule change proposal was designed to be technology neutral and would have accommodated these technologies as well as conventional generators and the more established renewable technologies. This introduced uncertainty relating to the potential entry time, location and cost of all of these technologies.

While there are inherent risks in being overly prescriptive as to which technologies are eligible for a particular policy, the SENE rule change process typified the significant complexity in finding a "one size fits all" solution.

In contrast, the CREZ projects in Texas and MVP in MISO were optimised for wind energy projects. The CREZ projects favoured technologies able to attract funding, which at the time was only wind. This single-technology focus simplifies the planning process and reduces the uncertainty (and therefore risk) involved. In California, the LCRI mechanism specifies that the energy resource being connected must be location-constrained meaning that conventional fossil fuels are unlikely to qualify.

Such an approach is unlikely to be successful through an AEMC rule change because of the implications for competitive neutrality. However, government policy can and does indirectly favour particular technologies; the RET, for example, favours technologies that can supply renewable energy at the lowest cost. As a result, the significant majority of utility scale renewable energy capacity built to fulfil the RET thus far has been wind energy.

While it would not be ideal to artificially limit the technologies to which a policy applies, in the interest of promoting the timely deployment of renewable technologies, policies that specify a specific delivery date, cost or ability to attract funding will indirectly favour particular technologies. This reduces the number of eligible technologies, thereby simplifying the associated network expansion planning processes. Depending on the desired policy outcomes, this could be a practical course of action.

2.4.6 Transmission planning for renewable energy goals

In the NEM the RET is included in the NTNDP forecast as a minimum amount of energy that must be generated by RET-eligible generators. As the NTNDP is a least-cost expansion plan it also represents the least-cost scenario for meeting the RET, given the inputs and assumptions used for the modelling. Alternative approaches to including renewable energy goals in transmission network planning are demonstrated by California, MISO, and Ireland:

- The CAISO annual transmission plan uses a least-regrets planning approach whereby transmission investments that have been deemed necessary under the largest number of potential RPS scenarios are eligible for implementation. The RPS investments are considered before reliability and economic investments (i.e. RPS investments are used as an input for analysis of reliability and congestion).
- The MISO has an approach that values policy flexibility. This is necessary because the MISO region covers multiple states, and the renewable energy targets are set by the individual states.
- Ireland developed the Grid25 conceptual plan and then allocated staged firm access rights to grid-connection applicants corresponding to when new transmission assets were to be built. This was an alternative to building network in response to individual connection requests.

The frameworks of California and Ireland feature a conceptual plan that is seen as the ideal future. This is an effective way of coordinating and optimising the transmission investments needed to meet renewable energy goals, especially when a large proportion of total new network investment is for this purpose. The MVP approach to policy flexibility is valuable in the multi-state context, but it may be hard to replicate in the NEM. The MISO sought to co-locate designated wind energy areas with existing gas pipelines so that both or either fuel source could potentially be used. In Australia, the gas pipeline network is sparser in comparison to the US network so this would not be possible in Australia to the same extent. Further, since the Australian government has an aspirational CO2 emissions reductions target of 80% by 2050 on a 2000 baseline it could be undesirable to use gas at significant scale as a transition fuel.

2.4.7 Net cost transmission expansion

In analysing a potential transmission investment an awareness of the potential benefits allows for an informed judgement on whether an investment is worthwhile. This is the basis for the RIT-T: a project must provide a net market benefit to be approved, unless it is deemed necessary for system reliability.

Since the RET is a public policy there could be justification for transmission investments for renewable energy integration to be similarly exempt from the net market benefits requirement. In this instance an investment decision could be based on a net present value analysis of a range of alternative options. The project demonstrating the highest NPV would be chosen, even if this was a negative value (i.e. earnings are less than the discount rate). This may be necessary to ensure scale efficiencies and allow public policy objectives to be met at least cost.

The international examples considered in this report demonstrate different ways in which the costs and benefits of a proposed transmission investment can be included in the planning process. The studies conducted by the MISO and ERCOT / PUCT in Texas calculated market benefit on a portfolio basis rather than for the individual investments. In California, transmission investments that are necessary to meet the RPS are not subject to a cost-benefit assessment. The following points provide further detail:

- In the MVP analysis the MISO calculated the present value of the benefits created by the entire portfolio of projects in 20 and 40 year present value terms. The cost-benefit ratio ranged between 1.8 and 5.8 for the scenarios considered. To comply with FERC regulation, the MISO had to demonstrate that the benefits were spread across the system in a manner commensurate with their costs; this was done by dividing the MISO region into seven zones and calculating a cost-benefit ratio range for each.
- In Texas, ERCOT and PUCT found that net market benefits would result from constructing the whole CREZ portfolio, but they were not obliged to calculate the costs and benefits to specific individuals or market participants, or demonstrate that costs and benefits incurred were proportional to each other.

- In the CAISO annual planning report, public policy investments are considered prior to reliability and economic investments. The public policy investments are not subject to a cost-benefit analysis as they have already been deemed to be necessary to meet the RPS target. In contrast to ERCOT / PUCT, the Californian RETI analysis was conducted at a component level rather than for the portfolio as a whole.
- The LCRI mechanism in California involves a cost-benefit analysis to assess the benefits of the proposal relative to other LCRI projects.

3 Conclusions

This report has considered the policy and regulatory frameworks relating to transmission network expansion for remote renewable energy projects in the NEM. Changes to these frameworks were proposed during the SENE rule change process conducted by the AEMC in 2010-11, however the original proposal was deemed to be too complex and too risky for consumers and TNSPs. Since this time the AEMC has conducted the comprehensive Transmission Frameworks Review (TFR) (completed in April 2013). The recommendations contained in this review, if implemented, could address some of the complications envisaged in the original SENE proposal.

For this report a review has been conducted of international transmission planning practises for remote renewable energy connections. A particular focus was on how international jurisdictions have addressed the concerns raised by the AEMC and Australian stakeholders during the SENE rule change consultation, principally in regard to minimising the risk of stranded assets. Based on this research a series of 'key learnings' have been developed:

1. The risk of assets becoming stranded by generators not connecting can be reduced by mandating minimum levels of firm and near-firm commitment to connect, and by limiting the amount of money that can be spent by TNSPs on scale-efficient extensions.
2. A conceptual plan for renewable energy integration could identify potential scale efficiencies and provide useful information for transmission planning initiatives.
3. Extensively involving stakeholders, particularly generation project developers, in the development of the conceptual plan would promote the efficient allocation of planning resources and reduce the risk of stranded assets.
4. Clear and certain targets for future renewable energy generation over timeframes relevant for network planning facilitate scale efficient network development.
5. Policies that limit the number of energy technologies under consideration simplify network planning by reducing the number of variables involved (e.g. entry time, location and cost).
6. The international examples show different ways in which renewable energy goals can be accounted for in transmission planning processes.
7. The most efficient fulfillment of renewable energy policies may require transmission network expansions that involve a net market cost.

Based on these learnings, this analysis suggests four possible actions that could make a positive contribution towards the efficient and timely integration of remote renewable energy projects in Australia. These are:

1. Implementing a funding allocation mechanism that allows for network extensions to be initially funded by a TNSP and then paid for by generators when they connect. This would overcome current disincentives on the part of generators and TNSPs to build scale-efficient extensions and cluster hubs.

2. Conducting a conceptual planning exercise for renewable energy integration. Ideally this would involve stakeholders and be based on a clear and certain renewable energy target defined over the long timeframes relevant for network planning.
3. Ensuring that the network development modelling processes adequately consider renewable energy projects that are contingent on scale-efficient network connections. This could involve using the results of an independent renewable energy conceptual plan to inform network modelling, or could operate by including remote renewable options directly in pre-existing modelling exercises.
4. Publishing a national methodology for the co-ordination of connection requests and identification of generation clusters. Such a process already exists in Victoria, California and Ireland.

These actions are complementary to each other, and could be implemented in parallel, or individually. For example, the results of a conceptual plan can inform network development modelling as well as decisions to fund scale-efficient network extensions.

Future efforts under the CSIRO Future Grid Cluster project could explore in more detail how these actions could be implemented. This would involve consideration of how these actions would interact with the existing frameworks, and how they could be effectively integrated. With renewable energy technologies expected to feature more prominently in the NEM energy mix in the coming decades, it is increasingly important that transmission planning frameworks recognise the unique characteristics of these technologies and allow for scale efficient development of the network. The learnings and options presented in this report are intended to inform debate and further analysis that can contribute to this outcome.

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