
**Final Report to
Clean Energy Council**

**Transmission Issues for Remote Renewable Energy
Generation**

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GLOSSARY

The following terms and abbreviations are used in this report.

AEMC	Australian Energy market Commission
AEMO	Australian Energy Market Operator
Deep connection cost	Refers to the generators paying for network upgrades beyond the local connection point to alleviate consequential constraints. Constraints up to a load centre big enough to absorb the power station output may need to be reduced.
NEM	National Electricity Market on the eastern seaboard and south-east region of Australia including Tasmania.
NERG	Network Extension for Remote Generation is an AEMC proposal to provide a regulatory framework to assisting the development of shared connection assets for remote areas. Connecting generators would pay a regulated access fee. Customers would under-write the costs if sufficient generating capacity does not eventuate.
REC	Renewable Energy Certificate issued under the Mandatory Renewable Energy Target of 9,500 GWh in 2010 moving to 45,000 GWh by 2020.
Shallow connection cost	Refers to the generator paying only the costs of immediately connecting to the existing grid. There is no payment required to alleviate constraints beyond the local connection point.

EXECUTIVE SUMMARY

Renewable energy generation is required to expand significantly over the next two decades. The Australian Government is planning to implement the Renewable Energy Target Scheme (RET), which mandates 45,000 GWh of additional renewable energy generation by 2020. The Government also intends to implement the Carbon Pollution Reduction Scheme (CPRS), which will make renewable energy technologies more competitive with traditional fossil fuel sources. Modelling undertaken for the Federal Treasury indicates that the CPRS will increase the opportunities for renewable generation as energy prices increase over time and conventional fossil fuel generation becomes more expensive due to the burden of carbon emission pricing.

Realisation of this potential will lead to a significant shift in the locations where electricity is generated from areas with large coal resources to areas with renewable energy resources. The areas with excellent renewable energy resources are along the southern and west facing coasts of South-east Australia and in the outback where solar and geothermal energy is more prospective.

A key challenge for transmission investment under these changes is to provide for an efficient pattern of infrastructure investment, with respect to time, location and with regard to trade-offs between alternative investment options. This challenge is affected by economy of scale issues that relate to large lumpy investments, free-rider effects, particularly when transmission expansion is in part funded by generation connection costs, and other system objectives that may have social good characteristics that are not fully reflective in market prices. The latter can include certain aspects associated with reliability or environmental objectives.

Generators setting up in remote locations need to be able to share deep connection costs and to obtain firm access for their financial commitment to transmission capacity. The current piecemeal bilateral planning processes will not necessarily lead to efficient outcomes. Additional measures are needed to provide better information for planning purposes on the long-run marginal cost of transmission capacity related to the transmission projects that are prospective. In addition demand side providers and embedded generators need relevant information on the value of their capacity in deferring network investment. This would enable them to bring forward competitive options well before the network projects enter the regulatory approval phase.

To improve the efficiency of transmission development and to provide for the transformation to a low emission generation sector, the key issues that need to be progressed include:

- The provision of information on the long-run marginal cost of alleviating the inter-regional and the main intra-regional constraints based on the cost of prospective augmentations and the impact of their need in relation to regional generating capacity and peak demand

- The provision of information on the value of the capacity of additional embedded generation at each major transmission node where local generation or demand side response is prospective.
- A regulatory approval process that values the benefits of a remote grid extension among local generators and local and remote customers having regard to the projected impact of the project on REC and energy prices.
- An inter-regional TUoS charging regime so that these benefits can be reflected in charges to customers across the regional networks according to the distribution of benefits, including through the impact of REC prices.

Generators

Generators need:

- Forward looking information on the long-run marginal cost of transmission augmentation related to specific constraints that would have a dominant effect on limiting generation output;
- An assessment of the value of embedded generation in the medium and long-term so that there can be efficient coordination of transmission, distribution and distributed generation and demand-side planning
- A process that values remote extensions and shares the risks with customers in an equitable manner based on a transparent risk analysis
- A mechanism to cooperate on developing share remote transmission extensions to new energy regions. The NREG proposal is a start in developing such processes, but it needs to consider customer benefits as well since not all the economic benefits of new generation are retained by generators.
- A mechanism to obtain firm access to new extensions to remote areas and across critical interconnections where they underwrite the deep connection costs.

TNSPs

TNPS need:

- An ability to earn higher rates of return on extension assets that have a higher risk of stranding than existing assets
- An opportunity to earn higher rates of return by deferring the equity returns on assets that have a deferred economic benefit profile
- A process to monitor the risk of stranded transmission capacity and the development of supplementary incentives to encourage reuse of stranded capacity where that maximises market efficiency.

Customers

Customers need:

- A process for inter-regional TUoS recovery that reflects the distribution of benefits from major augmentations to the main grid as well as large scale network extensions to the new energy regions where lower cost renewable energy is prospective.

1 INTRODUCTION

This report was prepared in July 2009 but was not issued as a final report until early 2010. It has not been updated for changes that occurred in the second half of 2009, specifically concerning the processes being considered for connection of remote generation by the AEMC.

1.1 Transition to new generation sources

Renewable energy generation is required to expand significantly over the next two decades. The Australian Government is planning to implement the Renewable Energy Target Scheme (RET), which mandates 45,000 GWh of additional renewable energy generation by 2020. The Government also intends to implement the Carbon Pollution Reduction Scheme (CPRS), which will make renewable energy technologies more competitive with traditional fossil fuel sources. Modelling undertaken for the Federal Treasury indicates that the CPRS will increase the opportunities for renewable generation as energy prices increase over time and conventional fossil fuel generation becomes more expensive due to the burden of carbon emission pricing.

Realisation of this potential will lead to a significant shift in the locations where electricity is generated from areas with large coal resources to areas with renewable energy resources. The areas with excellent renewable energy resources are along the southern and west facing coasts of South-east Australia and in the outback where solar and geothermal energy is more prospective.

1.2 Previous bulk system network development

Under previous state government owned vertically integrated monopoly electricity commissions, central planners in these utilities developed the bulk of the high voltage transmission system which currently exists. The back-bone was primarily designed to transfer remote coal fired power and hydro electricity to the major load centres. The topology of these systems was rather static, with incremental augmentations at either end of the backbone constructed over time to supply predictable demand growth at the major load centres from expanded power generation in the established generation regions.

Over time, in an attempt to share resources and reserve capacity, a number of relatively light interregional connections have been developed.

The first was associated with the Snowy Mountains Scheme and was primarily designed for power transfer from Snowy to the metropolitan load centres. At the time it was designed it provided a major capacity interconnection between Victoria and NSW. The next major interconnection was between South Australia and Victoria and became viable only because a large aluminium smelter was established at Portland with 500 kV supply. Subsequently NSW and Queensland were interconnected by means of a small HVDC link (Directlink) and later by a large scale HVAC interconnection (QNI). Basslink was completed in April 2006 between Victoria and Tasmania.

These interconnections were developed with specific roles and economic benefits in mind as summarised in Table 1-1. The Snowy interconnection and QNI both had substantial

Table 1-1 Interconnections and their benefits

Interconnection	Connecting	Primary Justification	Secondary Benefit
Snowy (1959)	Snowy to Melbourne and Sydney	Power transfer from Snowy to the major load centres – for peaking and energy reserves to back up base load power	Enabled surplus off-peak power to be exported from Victoria to NSW.
Heywood (1990)	Victoria and South Australia	Taking advantage of the 500 kV line for the Portland smelter to sell surplus power from NSW and Latrobe Valley to South Australia to displace high cost gas fired generation. Saving in reserve capacity in both states.	Enables surplus renewable energy to be exported to Victoria and NSW in off-peak periods.
Directlink (1999)	Queensland and NSW	Entrepreneurial link to arbitrage the energy price differences between Queensland and NSW prior to completion of QNI. The connection was delayed and most of this benefit was not realised.	Improved the reliability of supply to north-east region of NSW and the Gold Coast.
QNI (2001)	Queensland and NSW	Support Queensland using the surplus capacity in NSW at Liddell and Munmorah following the delayed commissioning of Mt Piper.	By the time the link was commissioned, Queensland had surplus capacity whereas the original justification was based on surplus capacity in NSW.
Murraylink (2002)	North-west Victoria and the Barossa Valley region of SA	Entrepreneurial link to arbitrage the energy price differences between Victoria and South Australia. There was a serious over-estimation of this value.	Regional network support in remote areas of Victoria and South Australia.
Basslink (2006)	Victoria and Tasmania	Provide drought insurance for Tasmania and export surplus renewable energy when available. Reduction in the need for reserve capacity in Victoria.	

economies of scale and the value of these interconnections would not have been realised in full initially, particularly with the surplus capacity in NSW and Queensland at the same time when QNI was commissioned. This was more a failure of the energy market to work efficiently rather than a failure in network planning in MMA's view. The long-term benefits of QNI are secure due to the diversity of peak loading between Queensland and NSW and the lower cost of gas fired generation in Queensland. The same applies to the Snowy and Heywood interconnections.

1.3 Market reforms and the challenge of efficient transmission investment

The electricity industry has substantially changed due to significant reforms that commenced in the early 1990's. The Hilmer report of 1993 and the Council of Australian Governments (CoAG) agreements of 1995 together provided for the structural reform of public monopolies, including the regulation of monopoly pricing by government businesses and open access to electricity and gas transmission and distribution assets. By 1998 the NEM was established, enabling competition between generators and large customers, facilitating trade across State borders, and providing for the competitive purchase of electricity in the wholesale market.

With these reforms the interconnectors have taken on a greater role in facilitating the trading of electricity. Three entrepreneurial interconnectors have been developed. However Directlink and Murraylink were converted to regulated status after a few years of entrepreneurial operations when it became clear that entrepreneurial revenues were insufficient for them to continue their operations in their original form. This error was due to poor investment planning by the sponsor. Only Basslink continues to operate as an entrepreneurial interconnector, obtaining its revenues exploiting the difference in peak and off-peak spot prices between Victoria and Tasmania. However its direct owner Hydro Tasmania does not necessarily obtain economic benefits commensurate with its cost. Its indirect owner, the Tasmanian Government on behalf of the residents of Tasmania, does receive the full benefits of Basslink through its role in supply reliability and drought insurance. Victorian electricity generators and consumers gain significant benefit from Basslink but without having to pay any significant costs.

Transmission planning in the current regulatory regime seeks to meet reliability objectives via arrangements that provide for competitive investment in transmission and generation assets, with funding provided by an industry characterised by competitive wholesale and retail markets, with an open access regulatory process governing natural monopoly assets and services.

A key challenge for transmission investment in this regime is to provide for an efficient pattern of infrastructure investment, with respect to time, location and with regard to trade-offs between alternative investment options. This challenge is affected by economy of scale issues that relate to large lumpy investments, free-rider effects, particularly when transmission expansion is in part funded by generation connection costs, and other system objectives that may have social good characteristics that are not fully reflective in market

prices. The latter can include certain aspects associated with reliability or environmental objectives.

The solution to this challenge must therefore resolve these issues in a manner that delivers a pattern of timely and locationally efficient investments.

Until recently transmission planning has assumed a consistent pattern of incremental investment to meet predictable growth in the established load centres, supplied in the main by predominantly thermal plant located in coal or gas regions. Economies of scale in transmission development have not been a significant concern and in most cases, incremental transmission has been associated with one or two generation projects and justified on the basis of providing market services (“entrepreneurial”) or network services (“regulated”). Long established transmission backbones have provided adequate capacity, allowing a shallow connection cost regime that has minimised free-rider issues related to network connection costs. However the new paradigm required to address climate change which requires replacement of high emission generation with low emission generation will require substantial new transmission capacity, including numerous long-haul transmission extensions to new remote renewable generation regions that may require anticipatory funding prior to these generation regions becoming established and to some extent self funding; one-to-one generation/transmission project concepts will not meet the likely need efficiently.

The AEMC has proposed the concept of “Network Extension for Remote Generation” (NERG) which would provide for new radial connection at a regulated price that could be shared by a number of generators committing to new power projects in an area where the grid capacity is inadequate or non-existent. The proposed NERG solution introduces the prospect of deep connection costs funded by small remotely situated renewable generators. While the process overcomes some coordination, economy of scale and free-rider issues, the question remains whether a deep costing regime may present a barrier to investment, and whether significant free-rider issues may be retained, especially in relation to new loads, potentially challenging the successful reconfiguration of the transmission system that is needed to deliver environmental policy.

The AEMO/NEMMCO SOO, ANTS and the National Transmission Planner provide some of the information to the NEM marketplace to allow investment decisions to be made, but there has been little attention to planning the backbone of the transmission grid to facilitate this major re-organisation to the structure of generation. Prior to the commitment to the CPRS and extended RET, there was little need to do much more than continue with business as usual. However, the MCE and the AEMC has recognised this issue as becoming more pressing in its review of Energy Market Frameworks in the context of Climate Change and in the establishment of the role of the National Transmission Planner.

1.4 MMA Commission

The Clean Energy Council has commissioned MMA to develop a high level report that will be used to influence the Energy White Paper, the AEMC Review of Energy Market

Frameworks and other processes occurring within the Australian Energy Markets. This report is the second draft of that response.

2 ISSUES IN NETWORK REGULATION

This chapter summarises the key issues that make it difficult to ensure efficient network development and to coordinate planning across the electricity supply chain.

2.1 Market failures

There are potentially a number of market failures that impede the development of an economically efficient electricity market. Transmission and distribution network service providers are usually natural monopolies and, in the absence of regulation, will usually be able to limit services and raise prices.

The key problems are:

- Asymmetry of information – not all are working from the same page of information
- Free riders – participants who contribute to an initial investment may find that other parties come in later at much lower cost and are better able to compete
- Economies of scale – bigger is cheaper per unit supplied but creates unused spare capacity.

2.2 Asymmetry of Information

Market participants seeking access to network systems are also usually at a disadvantage due to the fact that they do not know as much about the network as the party with whom they are negotiating. Generators especially embedded generators face significant information asymmetry when they attempt to negotiate with network service providers (NSP) for connection. The cost and benefits of connection at any point in the network is often only known to the NSP.

Regulation could ensure that such cost and benefits be regularly published so that potential investors in new generation capacity (whether existing generators considering increasing capacity or new generators) are able to negotiate with NSP so that benefits in terms of relieving congestion, lowering of losses and voltage support may be shared. The lack of such information makes it difficult to determine if the connection cost proposed by the NSP places an adequate value that proposed generating capacity would bring to the network and the market. Knowing the costs and benefits would also enable potential investors in generation capacity identify points on the transmission system that could economically absorb new generation capacity without potentially imposing high cost constraints on the transmission system.

The main risk of publishing network values is that demand side proponents could shadow bid up to the network value and thereby capture most of the value of their alternative option. However, it is reasonable to argue that better information lowers the barrier to entry and makes it more likely that competitive options will be offered and that the delivered cost of alternatives would be less than the network cost avoided. Competition thrives on transparency and market information. The fact that this has been lacking to

lacking to date helps to explain why the demand side contribution to network capacity management in the NEM has been minimal.

2.3 Free riders

The current regulatory regime requires those seeking connection to fund the cost up to the point of connection. For a single remotely located generator the additional cost of connection is likely to be insurmountable.

While a number of small generators and customers would be better off sharing in the investment, the temptation is to free ride and avoid paying for the expense, hoping that it will happen anyway. The free-rider incentive may inhibit the ability to form a consortium to negotiate a favourable contract with the network service provider.

If the costs can be shared between multiple generators, the likelihood of a successful network extension increases. But the extension may not eventuate due to the strong incentive to free ride on the efforts of early movers.

2.4 Economies of scale

Networks are usually characterised by economies of scale. This means that it is much cheaper per unit of service delivery to build at large scale. A single transmission line might provide for efficient service over a 50 year life but over a long distance might initially only supply 10-20% of the ultimate load.

This presents a problem for the development of wind farms, solar and geothermal generators which rely on remote resources. During the initial phases of development, the installed capacity is likely to be small relative to the total potential resource. Unless the developer owns the full resource, the transmission network will only be built with sufficient capacity to meet the needs of the immediate development, rather than the total potential capacity of the resource. The initial developer will have no incentive to fund the installation of network capacity greater than its own needs. However, this is likely to be sub-optimal from society's perspective, as the savings from economies of scale will be lost.

Current arrangements in the industry do not provide any robust mechanism for additional network capacity to be funded on the basis of a longer-term societal perspective. Additional network capacity can only be funded by the broader customer load if it can be shown that the project meets the regulatory test if it is the best alternative, mostly with reference to forecast loads and committed generation.

However, building network capacity beyond the needs of the first proposal will most likely have a negative net present value, that is, from the regulatory test perspective, it is better not to install the additional network capacity since there is no generation capacity proposed that will immediately use the network capacity. As a result, the first proponent will only build what they need. When the second proponent is ready, the network will have to be augmented, and so on. Proceeding in this piecemeal fashion means that, over time, the network costs more than it would if it was built to the final capacity in the first

instance. This problem has been acknowledged in the AEMC's current climate change review.

3 CONGESTION OF THE TRANSMISSION GRID

3.1 Coordination of investments in generation and transmission

In a vertically integrated electrical system, the utility coordinates the generation, transmission, and distribution aspects of the business to ensure that both long and short term efficiency objectives are met in the provision of electricity services. In the short term, these objectives include the optimal dispatch of energy and ancillary services and the real time management of transmission constraints. In the longer term, a central planner would consider the need for coordinating investment between the generation and transmission sectors to optimise the location of generation capacity and the transmission capacity between load and generation centres. This involves considering the location of generation capacity reserves and the transfer capacity needed to ensure that generating capacity is available to meet peak demands at a local and regional level whilst maintaining an efficient reliability level¹.

Within a competitive market structure, where generation and transmission are under separate ownership, that coordination takes place through other mechanisms. These include:

- price signalling from competitive markets;
- hedging contract arrangements to secure long-term revenues and benefits and thereby manage energy price risk;
- contracted network services for access to the grid; and
- explicit coordination rules and operational processes to optimise resource utilisation whilst maintaining supply reliability and service quality.

Many of these mechanisms are related; wholesale market price signals can influence bilateral contract prices, and explicit coordination rules and operational processes seek to extend beyond the limits of coordination that is facilitated by the organised wholesale and contract markets.

One important element of the pricing signal is the exposure of market participants to system marginal prices. In the context of the wholesale energy market, the system marginal price includes the marginal cost of energy, of losses and of congestion. In a multi-regional system such as the NEM, system marginal prices respond to complex power flows over great distances, influenced by distributed decision making, transmission losses and capacity constraints. The existence and use of assets within the system can influence considerable price variation. The level and volatility of system marginal prices can therefore inform decision-making, including operational decisions regarding existing assets, and longer-term decisions relating to investment and disinvestment.

¹ The efficient reliability level minimises the total cost of unserved energy and capacity reserves.

However as an investment signal, system marginal prices have been found to be insufficient to ensure timely network investment in the case of large and lumpy transmission investments. The introduction of large increments of transmission capacity in response to identified congestion can succeed in resolving the transmission constraint, thereby diminishing the difference in system marginal prices either side of the previous constraint, and thereby destroying the source of revenue that a trader seeks to trade in energy or ancillary services across a transmission element. This problem arises due to economies of scale in transmission capacity.

This deficiency has been seen in the failure of the Murraylink and Directlink as entrepreneurial projects. The developers of Murraylink had expected to enjoy profitable price differences between Victoria and South Australia that were quickly eliminated by the development of Pelican Point and Murraylink at the same time. That Murraylink proceeded when this outcome was foreseeable demonstrates the difficulties in investment execution and risk management. Even with the best intentions, under the current NEM market model, there can be no guarantee that price differences would remain sufficiently large and sustained to provide sustainable revenue even though the investment may be efficient.

This limitation in the ability of competitive pricing outcomes to fully fund efficient new investment is a feature of most organised electricity markets around the world, and an important factor in the complimentary use of non-market institutional arrangements, including regulatory processes, to assist investment decision-making and project funding.

In addition to these scale issues that can erode marginal congestion prices and therefore reduce the pay-off from an investment, in the Australian context pricing signals are further limited, thereby affecting the quality of market signals, and therefore investment incentives:

- wholesale market pricing is regional, constraining signalling benefits to inter-regional decisions. Unlike some markets overseas, the NEM or the WEM do not feature nodal pricing, therefore preventing published market prices from revealing locational signals within the state-based pricing regions. This affects intra-regional investment behaviour because intra-regional congestion and constraints may not be apparent; and
- wholesale market price signals (in the NEM) are limited to the energy and ancillary service markets which can constrain the ability of the pricing regime to convey information, and which can limit pay-off opportunities for new investments. Other market designs provide a broader range of pricing information and associated revenue opportunities, such as the design of the WEM, which includes a capacity market and an associated price for capacity. The Standard Market Design of the Federal Energy Regulatory Commission in the United States, reflective in the PJM and NYISO markets, features competitive markets for energy, capacity, ancillary services, as well as providing for competitive markets for demand management and financial transmission rights. These markets therefore provide a broader range

provide a broader range of pricing information, and provide greater scope for the market to fund merchant investment.

Limitations in the extent and quality of pricing information requires investment information to be augmented by other non-pricing means. This can include negotiations and transactions in the bilateral markets, the provision of information by market and system operators (e.g. resource adequacy assessments, congestion and demand studies, the publication of transmission loss factors etc.), and other non-market measures, such as regulated information or prices that are the result of open-access arrangements.

Especially in the case of large scale transmission investment, the limitation of the extent and quality of competitive pricing signals can diminish opportunities for merchant investment, thereby moving investment behaviour into regulated processes.

Even if pricing signals are adequate, and scale issues are not material, investment in transmission can be distorted by free-rider effects. Transmission augmentations that remove constraints or congestion, for example, deliver benefits that can be much more extensive across a network than can be recovered from the bilateral contract market, or from regulated cost recovery. Market arrangements and regulated processes are constrained in their ability to exclude free-riders from the potential benefit. As a result, the primary sources of revenue to recover the costs of transmission services have to be the generation and customer beneficiaries. However, this is not necessarily efficient or equitable under the current arrangements which have not incentivised much merchant investment, and in the case of regulated investment, have limited cost recovery to within the jurisdictions containing the interconnection transmission assets. This principle did work reasonably well under state ownership for the Snowy and Heywood interconnections due to their physical location and the particular market benefits they created. However, it will not work if South Australia is to be the major renewable energy power house and export large volumes of energy to the eastern seaboard regions of the NEM.

In the case of the competitive Australian electricity markets, MMA is of the view that the current wholesale market design and procedures will not provide sufficient investment signals, nor on-market revenue opportunities, to fund locationally and temporally efficient investment in transmission capacity to support renewable generation policy objectives. Further, regulatory approaches to provide transmission capacity may have similarly difficulties in delivering desired outcomes. This will require the attention of the policy makers, with a need for supplementary market and non-market institutional arrangements to ensure the industry can efficiently deliver policy objectives.

In the context of providing for remote renewable energy generation in Australia, significant coordination and incentive challenges will need to be resolved:

- Pricing signals from the competitive wholesale electricity markets provide limited locational information to optimise the siting of potential generators;

- Pricing mechanisms in the competitive wholesale electricity markets limit the cost recovery options that are available to fund merchant investment, even between efficiently priced nodes;
- Cost recovery arrangements for regulated transmission services are constrained to network boundaries, preventing investment beneficiaries from beyond these regions from contributing to infrastructure costs;
- The need to construct new transmission backbones to regions with significant solar and wind resources present scale and free-rider issues that may distort investment behaviour, and even if partially funded through deep connection costs, may present a barrier to new investment, both for generation and transmission; and
- Investments that anticipate the future development of the transmission system, of policy developments, and of the development of new generation regions, have heightened risk, potentially requiring additional cost recovery or some provision that can assist the risk management of stranded or redundant investment.

The competitive energy market frameworks will therefore need to address increasing needs for investment information, will need to provide a coordinative solution to assist the market deliver an efficient investment outcome, and may need to address cost recovery issues where current arrangements may present investment barriers.

In the case of the South-west interconnected system (SWIS) in Western Australia, the development of the network is controlled by the Economic Regulation Authority with Western Power Networks the asset owner. The challenge for Western Australia presented by the need to extend the 330 kV transmission system to Geraldton is very much a cost and economies of scale problem. The new extension is needed to support new wind farms and coal based projects north of Perth and yet the cost (more than \$300 M²) is out of proportion to any one new potential project. Not only is funding a problem, but the staging of development to align with the potential power projects will be challenging from a risk management perspective.

The key issues in determining the optimal timing and balance between generation and transmission investments are:

- Staging and cost recovery options for new network extensions to remote, generation resource-rich areas; and
- Developing the correct incentives and supportive mechanisms for augmentation of the existing shared regulated transmission network.

Chapter 5 discusses the former bullet point and the remainder of this chapter discusses the latter bullet point in a general context.

² Energy Regulation Authority, Final Determination on the New Facilities Investment Test for a 330 kV Transmission Line and Associated Works in the Mid-West Region of Western Australia, Submitted by Western Power, 3 September 2008

3.2 Constraints that may influence generation development

As generation moves from mainly fossil based fuels to renewable sources of energy, constraints are likely to develop in different parts of the network as generation relocates from areas with large coal resources to areas with large wind, geothermal and solar resources.

For example, we would expect:

- That spare transmission capacity may arise between coalfields and major load centres (such as between Latrobe Valley and Melbourne and between Hunter Valley and Sydney) as coal generation capacity is retired
- Reduced energy flows from Victoria to NSW and South Australia as the spare brown coal fired power is eroded through plant retirements in response to high carbon prices
- Increased power flows and associated constraint impacts from South Australia to Victoria as new renewable energy displaces coal fired power in Victoria and NSW. Some of the spare Victoria to NSW export capacity may be taken up by the renewable energy flow to Victoria to the extent permitted by interconnection capacity.
- Increased power flow from Queensland to NSW as gas fired generation based on coal seam gas in Queensland displaces some black coal fired power in NSW and Victoria.
- Greater volatility of power flow on the Snowy and Victoria – SA interconnections as wind power in Victoria and South Australia that comes and goes on a daily and weekly basis is replaced by hydro and gas fired generation.
- Reduced power transfers from Victoria to Tasmania as gas fired generation and renewable energy generation increase in Tasmania. This trend will depend on the long-term hydro yield which has been in decline over the last two decades.
- Pressure to build network capacity in the SWIS and the smaller regional systems to be able to connect the readily available renewable energy resources (wind and solar).

Nuclear plants may be able to locate in NEM areas with strong transmission capacities vacated by the coal fired plants, especially given the need for cooling water also released by the coal plants. They would also benefit from the technical and skilled labour resources in these regions. However, such locations will be less likely to be suitable for wind, geothermal or solar plants which will have to locate in areas where resources are available rather than where the existing transmission system has sufficient capacity to carry the energy generated to the market. Shifts in generation concentration from coal areas to regions surrounding gas and wind resources may cause transitional infrastructure constraints that require major new transmission system investment and augmentation to address. The more critical locations for constraint in the existing NEM system are:

- Between Victoria and South Australia due to changes in wind and geothermal power generation
- Between Queensland and NSW due to changes in gas fired generation.

In the SWIS the major concern is the need for enhanced transmission capacity north of Pinjar to Geraldton to connect new thermal and renewable energy generation resources.

3.2.1 Efficient transmission and residual constraints

An efficient transmission system is an occasionally constrained transmission system. Transmission systems are sometimes entirely unconstrained simply due to economies of scale in development that result in spare capacity because transfer capacity comes in big blocks. Generators need to be able to assess the worst long-term case to determine the level of constraint that could not be cleared by transmission augmentation alone. This may determine the optimal size of the generation resource, particularly in the case of high capital cost renewable energy. This requires information from TNSPs on the available options for augmentation, their capital and operating costs and the extent to which they would relieve constraints. What is missing in much of the published planning data is information on the relationships among generation levels, peak demand levels and power transfer levels that would enable these risks to be assessed by market participants. These relationships would be based on maintaining reliability of supply at local and regional levels.

3.2.2 The long-run marginal cost of transmission

Constraints are economic if the long run marginal cost (LRMC) of augmenting the transmission system is greater than the value of relieving the constraint. If the LRMC for specific capacity tranches is known to investors, the value of capacity increments at any point on the network can be determined. Currently however, the LRMC of relieving transmission constraints is not available or unknown until a TNSP conducts a regulatory test and even then it is not properly disclosed in a way that co-ordinates supply/demand planning. Given that congestion costs are influenced by complex power-flows and market participant behaviour that extends beyond the network regions of a TNSP, there is a question whether the TNSP has an adequate basis to appreciate the costs of congestion in the wholesale market context that is relevant for market participants and end-users.

Investors in new generation capacity (whether existing generators considering increasing capacity or new generators) do not have this information during their capacity planning process. This makes it difficult to determine if the value that new generating capacity brings to the market would exceed the cost of relieving the transmission constraints at from that point in the system. Investors in new generating capacity do not know if the constraint their proposed generator would create could be relieved economically either by passing the regulatory test or by them funding the augmentation themselves. Knowing the LRMC of transfer capacity would thus enable potential generation investors to identify points on the transmission system that could economically absorb new generation capacity, including the cost of augmentation.

Therefore, if firm access is not accessible, it is necessary for generators to be able to quantify the long-run marginal cost of transfer capacity to major load centres (where residual constraints on generation are not significant) so that they can assess what level of

constraint on their generation resources is optimal. That would define the worst case that they might have to live with in absence of local load growth. This principle would alleviate the fear that a generator would face an adverse constraint even though the network augmentation options are managed in an efficient and timely manner.

For example, if the long-run marginal cost of transmission is \$500/kW which translates to about \$41/kW/year over 50 years at 8% discount rate, the market cap price is \$12,500/MWh, the short-run marginal cost is \$50/MWh, then the efficient level of constraint is 3.3 hours per year³. This could provide a basis for generators to assess the maximum long-term impact of constraints.

3.2.3 Value of embedded capacity

Another way of looking at this challenge in a decentralised planning framework, is that the value of embedded generating capacity relative to alternative transmission augmentation needs to be published at least annually so that generators and demand side providers can coordinate their long-term planning with that of the network.

Accordingly, MMA has proposed the concept of a Value Function that would describe the factors that determine the timing of a proposed network augmentation. By relating the timing of a specific new asset to the relevant quantities of local peak demand and local generation at nearby nodes as appropriate, it would be possible for an investor to determine where best to locate generation sources without causing costly constraints. This would not require a great deal of additional analysis by TNSPs. It would require some interpretation of the planning and network performance studies so as to create useful information.

Such information ought to be an output of the NTNDP for designated options so that it becomes a useful planning resource. It is important that market participants are able to obtain this type of information to support efficient planning processes.

3.2.4 Impact on TNSPs – stranding of network assets

At present, no significant stranding of transmission assets has occurred where asset values have been significantly reduced due to changes in the configuration of demand and/or supply. The major sources of generation have remained the same, supplying the same load centres since the transmission system was initially planned. As older coal fired power stations were retired, newer larger units replaced them and the network capacity has been expanded as needed. The CPRS and the enhanced Renewable Energy Target schemes however have the potential to lead to the stranding of significant assets and thereby affecting the revenue and value of TNSPs due to a shift in the centres of generation away from the major coal fired generation areas like the Latrobe Valley and

³ Dividing \$41,000 per MW per year as a transmission cost into the loss revenue of (\$12,500 - \$50)/MWh gives 3.3 hours per year as the efficient level of constraint assuming that the constraint prevents access to a constrained supply system. Greater hours of constraint would be applicable if the local system has higher short-run marginal costs or the remote system does not become capacity constrained when the local constraint applies. This is because the denominator would be smaller. For example if the local SRMC is \$250/MWh and the remote system has typical peak SRMC during constraints at \$1000/MWh, the the optimal level of constraint would be $41,000 / (1000 - 250) = 54.7$ hours per year.

Hunter Valley to towards the remote areas in northern South Australia and outback Queensland. Compensation issues could arise for TNSPs that are significantly affected and it is likely that the regulatory system will need to adjust to take this potential into account.

Due to the labour intensity of constructing and dismantling transmission line component for reuse, it is unlikely that existing transmission line assets could be redeployed. Transformers and voltage control plant can be redeployed relatively cost-effectively providing they have sufficient residual technical operating life. If generators had to pay deep connection costs and stranded assets were charged accordingly, that would provide economic incentive to reuse stranded assets where that is feasible. Under shallow connection pricing, an economic outcome is less likely without some form of subsidy from customers who would otherwise have to pay for new transmission assets elsewhere. At the present time we do not see any examples where there are obvious benefits from providing special incentives to reuse stranded transmission line assets. For example, even if there were significant retirements in the Latrobe Valley, the spare capacity could be reused by gas fired generation, new coal fired power with carbon capture and storage, nuclear power or for augmentation of Basslink for increased exports of renewable energy from Tasmania.

This is a matter that should be kept under review by the AEMC to ensure that the transmission system is being used efficiently having regard to new and incumbent generation resources. This may require supplementary payments to provide incentives for reuse of stranded transmission capacity.

3.3 Customers exposure

Besides the cost of connection, generators do not pay for the use of the transmission system except when they are net importers of energy. Ongoing transmission use of system (TUoS) charges are paid by customers. Any shifts in the configuration of the supply of generation towards renewable generation areas could potentially expose customers to large increases in the TUoS charges associated with large increases in network capacity to pay for peak power flows from intermittent sources. It becomes more important to review the allocation of transmission costs to ensure they are proportional to the magnitude of benefits.

The regulatory regime is currently geared towards protecting customers from unjustified increases by requiring proponents for transmission investment to undertake a regulatory test where only proposals that have a net economic benefit to all those who produce, consume and transport electricity in the NEM are allowed to proceed unless the augmentation is required to meet reliability or service standards. If this process of evaluation is rigorous and all costs and benefits and risks are taken into accounts, then customers' interests would be protected. However there have been manifest failures in the past where the evaluation process has failed to produce a credible outcome either due to

to artificial regulatory constraints⁴ or sometimes just due to poorly conceived analysis⁵.

What customers need out of these reforms are:

- An active process by TNSPs that seeks out beneficial network development opportunities irrespective of whether there is a willing proponent. Perhaps there needs to be a “finders fee” awarded to an entity that brings a project to approval, due to the significant cost in system and energy market studies needed to confirm viability before the regulatory investment test is enacted formally⁶;
- Competent review of analyses to ensure that costs, benefits and risks are properly accounted for in the aggregate;
- A credible assessment of those factors that may alter the distribution of benefits among generators and customers, so that as much as practicable those that benefit most contribute more to meeting the costs.

There is value in a review to understand how customers benefit from investment in remote renewable generation, in particular to understand how these benefits may be dispersed beyond existing regional boundaries. A study such as this can inform the development of options for funding long-distance transmission development that will likely deliver benefits beyond the TUoS charging boundary. The benefits analysis would provide a comparative basis for generation establishment and connection costs and transmission costs, thereby informing the development of cost sharing schemes between generators and loads, and between regions and sub-regions.

3.4 Summary

Thus the efficient management of constraints under the current market frameworks requires:

- Consideration of additional incentives for the identification and successful approval of efficient transmission works to alleviate constraints
- Information on the long-run marginal cost of transmission capacity between constrained zones for blocks of additional capacity linked to specific upgrade options
- Information on the short and medium term value of embedded generation capacity relative to alternative transmission investments to coordinate planning with demand side service providers and local generators.

⁴ Such as partial SANI where the efficient option was not immediately approved because it did not have a willing proponent! Transgrid was the unwilling proponent.

⁵ Such as the abolition of the Snowy region where the change in intra-regional MLFs arising from the change in dispatch from the boundary change was not included in the benefit analysis, even though the supposed benefit was a very small difference between too large values. In such cases modelling consistency is imperative.

⁶ A finders fee would encourage well informed participants to identify efficient investments which having received regulatory approval could then be sold to investors as infrastructure projects. This would overcome the reticence of TNSPs to get involved in project concepts that straddle jurisdictional and service territory boundaries.

4 LOCATIONAL SIGNALS FOR NEW NETWORK INVESTMENT

The transition from the current generation sources could require a change in how new transmission assets are funded as the incremental approach to network expansion/augmentation is no longer valid as a general principle. It could require significant investments in transmission assets compared to the current transmission asset base which a single low emission generation project may have difficulty funding. The current practice that requires customers to pay for the general incremental reinforcement and augmentation of the transmission system while generators pay for connection is not geared towards meeting the funding needs for a fundamental realignment in the supply demand structure. Chapter 5 discusses how this applies to the difficult problem of connecting remote generation under substantial economies of scale. The following discussion focuses on nearby connection within the existing grid.

4.1 Implications for generators

Shallow connection costs may not reflect true costs of connecting large scale renewable generators to the existing transmission system if the configuration of the transmission system needs to be fundamentally altered due to the relocation of the sources of generation. Particularly for large scale wind farms that can efficiently operate with some residual constraints, the planning process must consider how the value of the output would deteriorate as the generating capacity is increased due to:

- Lower energy prices in the market
- Lower REC prices
- Lower transmission marginal loss factors
- Greater output constraints.

The latter two items are more difficult to assess due to confidentiality of network data and to the inherent complexity of dynamic transmission system analysis. The TNSPs are best placed to do this type of analysis and to provide relevant data that is suitable for economic performance analysis and planning by market participants.

As stated in section 3.2.2, investors in embedded generators would also benefit from understanding the LRMC of relieving constraints in the transmission system. Such investors could identify constraint points in the transmission system with high LRMC and seek to invest in embedded generation on the load side of the constraint. They would also be better prepared to avoid relying on transmission through regions with higher LRMC for constraint reduction.

Other options that can assist investment decision making include:

- The development and implementation of nodal pricing in the Australian electricity markets, with nodal boundaries that are relevant to the topology of the power system,

and to the pattern and spread of load, generation and significant transmission assets. A nodal pricing market model can co-exist with a regime of zonal or regional pricing that is applied to load. Nodal pricing provides short-term pricing signals but does not help the long-term planning analysis of itself.

- The development and publication of nodal shadow prices that are distinct from prices used in the settlements process of the Australian electricity markets. These shadow prices should distinguish between their constituent components, including the marginal cost of energy, or losses and of congestion.
- The development and publication of marginal congestion factors, preferable dynamic or temporal, thereby providing a parallel to the marginal loss factors that are published by the AEMO. These would be used to monitor the trends in the marginal cost of constraints.
- The publication of disaggregated system costs that can provide an alternative to marginal prices in an understanding of the cost of meeting load. Some consideration would need to be given to system costs in the absence of optimised unit commitment in the scheduling logic, and therefore costs that may not feature start-up, shut-down and other commitment costs associated with generation.
- The publication of congestion studies that reflect inter-regional relationships in a market context.

In addition to these informational options, there is benefit in exploring how these options could be provided via extensions to the design of the organised wholesale markets in Australia to provide additional revenue opportunities for investment.

Given that nearly all transmission development would be approved through the regulatory investment test, the main focus of the AEMC should be to ensure that the National Transmission Planning process provides quality output information that is useful for planning coordination across the supply chain.

5 CONNECTION OF NEW REMOTE LOADS AND GENERATION

5.1 Extension of the main back-bone to remote regions

The current regulatory regime requires those seeking connection to cover the cost up to a point of connection to the existing network where the power can be transferred with minimal constraint. For a single remotely located generator the additional cost of connection is likely to be insurmountable due to economies of scale. If the costs can be shared between multiple generators, and the connection built at a suitable scale for long-term development, the likelihood of a successful network extension increases as the cost per generator becomes acceptable. But the extension may not eventuate due to the strong incentive to free ride on the efforts of early movers, particularly if the initial development leaves significant spare capacity.

The presence of economies of scale in networks combined with monopoly provision of network services means that investment in network capacity to allow low emission sources of generation to access the wholesale markets may be suboptimal. This is likely to disadvantage remote and distributed low emission technologies facing information asymmetries.

Without major changes in the transmission infrastructure, low emission technologies may find it difficult to achieve connection, even though they may be competitive once the transmission infrastructure has been established. Even if they do achieve local connection, the full value of their output may not be realised if interconnection export capacity becomes unduly constrained. This alludes to the problem we discussed above concerning the long-run marginal cost of transmission capacity. If that were made more apparent, it would be easier for generation investors to identify the threats to their project viability and influence the network planning process in a more informed manner.

Renewable (wind, large scale solar energy and geothermal) generators are frequently located in relatively remote sites, where the electricity distribution or transmission network either did not exist or was not designed to handle the quantity of energy and power output of the wind farms. As a result, the networks have to be extended or strengthened. The current regulatory regime requires those seeking connection to pay for the cost up to the point of connection. For remotely located wind farms, the additional cost of connection often proves to be insurmountable. The regulatory arrangements do not provide a mechanism for the sharing of such costs in anticipation of other remote generators, or the spreading of these connection costs to the general load. Remote generators are faced with either paying for the connection themselves, or attempting to form a consortium of other potential generators in the area to pay for the connections.

5.2 Access rights

Shallow connection costs may not reflect true costs of connecting large scale renewable generators that may be located in locations remote from the existing transmission system if the configuration of the transmission system needs to be fundamentally altered due to the relocation of the sources of generation. Better incentives for connection of remote generation and the reuse of stranded transmission assets would be achieved by moving more of the transmission system costs back to generators. However, this will need to be balanced with an improved allocation of property rights for generators who have paid for the strengthening of the network. These generators should not be exposed to the threat of being constrained off when they have specifically paid for the installation of additional transmission capacity so that they can get their generated energy to the market.

Better incentives could be provided for paying for deep connection costs where it is economic to do so by defining access rights for the sponsoring generators for the firm capacity available. Such rights would guarantee that other generators are constrained off first in the merit order when loss adjusted bid prices are equal, usually at the market floor price or near the negative of the REC price for a renewable energy generator. Once regional prices are established at the remote node, then inter-regional settlement surpluses could be provided to firm up the effective transfer capacity. By whatever means, providing access rights would be a helpful move where free-rider risks are significant.

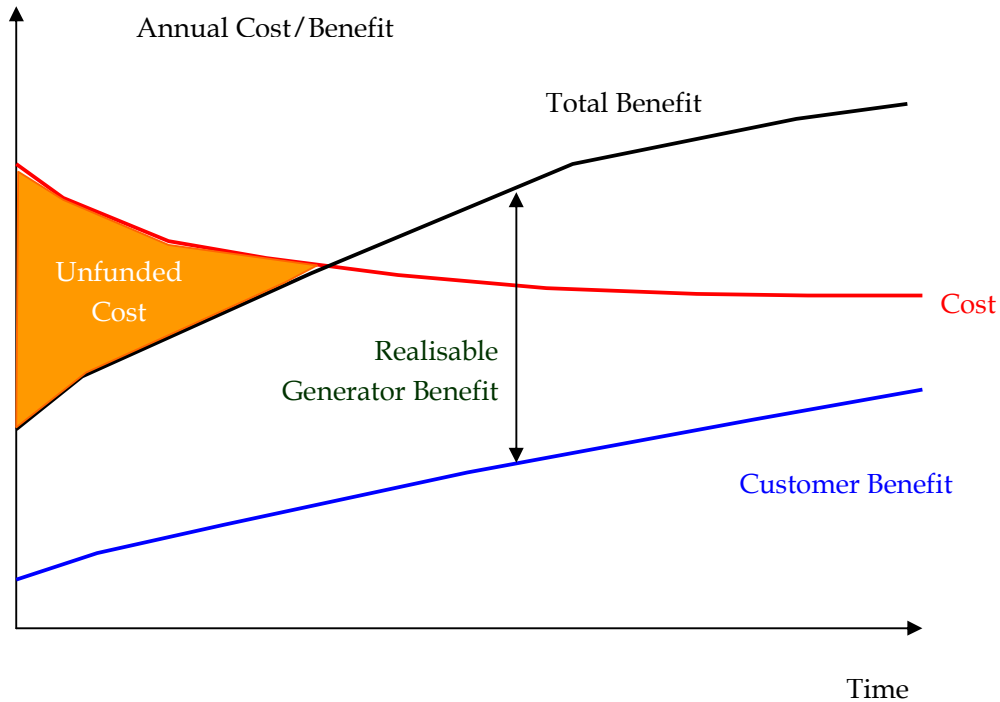
5.3 Interconnection Access

Another matter related to access rights could well apply if large scale renewable generation is developed in one region and needs to be exported to another larger region, such as reflected in the South Australia/Victoria/NSW situation. In such a case the rise of constraint across the remote interconnection may be a substantial risk. This may be partially overcome by acquisition of inter-regional settlement surpluses. However there remains some risk because these settlement surpluses themselves are non-firm and there are residual risks in trading across interconnectors. Further reform of transmission arrangements could provide for firm settlement surpluses across interconnectors up to a nominated capacity with the undistributed surpluses used to fund an insurance pool to cover the risk of network outages making the surpluses within the nominated capacity non-firm. Such arrangements would also assist inter-regional trading and make the establishment of more regions more viable than it is under the current non-firm settlement surplus arrangements.

5.4 Asymmetric costs and benefits for remote generation

The key problem with economies of scale that applies when opening up remote generation sources is illustrated by the diagram in Figure 5-1. The total real annual cost with conventional debt and equity funding is shown by the red line. The blue line shows the customer benefit that remains from lower energy prices arising from increasing volume of lower cost generation. The black line shows the sum of the generator and customer benefits with the difference between the blue and the black line being the

Figure 5-1 Costs and benefits for transmission with economies of scale



generator benefit. There is a net present benefit overall because the total long-term benefit exceeds the long-term costs. However, in the initial period there is an unfunded cost. The big question is how does this gap get funded?

Under the previous public sector ownership such unfunded costs were recovered by the utility through additional Government debt funding, though reduced dividends or through higher prices paid by customers in excess of the true economic value of the asset. Under the current regime, this additional cost would become part of the TNSP's revenue through an increase in the asset base commensurate with the red line. However, if this is a major investment, the full cost impact on customers might be quite noticeable, particularly without inter-regional TUOS arrangements to share the burden. Some alternatives that might be considered for large scale projects related to remote connection are:

- An initial contribution from the remote generators, which increases as their projects become commercial and which reflects a reasonably shallow connection contribution that is consistent with the treatment for incumbent remote generation. It would represent payment of an option fee to gain access to greater capacity if needed subsequently.
- Recover the costs generally from all customers through inter-regional and local TUOS charges as currently recognising that the customers will receive the later benefits. This process could increase the share of the cost paid by generators later to compensate the customers for under-writing the development risks. As the market becomes more

competitive and the value flows back to customers, more of the network costs can again be funded by customers.

- Recover the cost through Government funding of low emission enabling infrastructure projects. In this case tax payers nationally share the cost through increased taxes in the short-term or increasing Government debt.
- Offer the TNSP a higher rate of return to defer the equity return to later in the project life so that initial costs are only debt related. In effect the early losses would be capitalised to some extent. The higher rate of return could be commensurate with the internal rate of return of the asset if the case is compelling. From the TNSP's perspective, the higher rate of return reflects the higher risk associated with deferred revenue and increased debt funding or reduced equity returns in the early period.
- Include a balancing component which makes up the gap between funding cost and the foregoing revenue sources. This could be funded by revenue from the sale of permits under the CPRS during the transition phase and would eventually decline to zero unless it turns out that the planning basis proves to have been too optimistic.

Other options include:

- Extending the design of the organised wholesale markets to provide greater revenue opportunities for investment, including nodal pricing, forward capacity markets, tradable financial transmission rights to allow the trading of congestion costs, priority dispatch associated with access rights etc;
- Shared ownership and joint development schemes such as those provided by FERC Order 679. This would enable a joint venture by a generator, retailer and network owner to formulate a project that was financially viable and met their own business objectives. Access to other parties would be available on a regulated basis if needed; and
- Improved procedural and organisational arrangements to manage remote renewable generation, thereby providing arrangements that may aggregate and consolidate connection applicants, develop shared connection solutions, share connection costs, and provide some means for minimising free-rider and scale diseconomy issues. The outcome may lower transaction costs and correct incentives to ease investment barriers. Examples include Ireland's 'gate system', Texas' designation of CREZ's, California's third category of transmission –renewable trunk-lines, etc. These schemes present potential elements that could feature in the proposed NERG arrangements for Australia.

5.5 Network Extension for Remote Generation

The Network Extension for Remote Generation (NERG) proposal of the AEMC invites renewable generation to pay deep connection costs, albeit managed through a coordinated process that aggregates potential generation and shares connection costs. It may overcome significant cost barriers to new investment in affected regions, depending on the relative

the relative scale of initial generation and transmission capacity. However, it may still have some hurdles to overcome in that:

- It is not clear how the funding deficit would be overcome if initial generator and customers benefits were insufficient for an efficient large scale solution. For example an efficient scale might be 2000 MW capacity out of the Eyre Peninsula but the initial development might only be 500 MW for a few years.
- It is not clear what would happen if new loads emerged in the high generation areas to take advantage of the low MLFs. The remote extension would then become a shared asset with customers and the basis of payment might reasonably need to change, especially if the new load reduced generation export constraints. This is considered further below in section 5.8.

5.6 Overseas Approaches

The connection of remote generation is a major issue in many electricity markets around the world, particularly as many markets are accommodating environmental policies that are mandating requirements for renewable generation. Solutions are varied:

- Regions such as Great Britain, and to a certain extent Denmark and Germany (in the case of offshore renewable generation developments), have implemented a 'super-shallow' grid connection policy that requires the transmission operator to fund transmission expansion costs close to the connection point of the generation asset. In Denmark and Germany, costs are largely socialised, funded by a postage stamp TUoS charge levied on demand customers. In Great Britain transmission costs are funded largely via a locational TuOS, partially levied on generators.
- The Ontario, New York and Irish markets have followed a 'beneficiary pays' approach. Ontario has a deep connection cost policy for new generation connections; there is a proposal however to adopt a shallow connection cost approach with a locational TUoS that is charged in part to generators to provide locational signals and to recover some deep connection costs. In Ireland, connection costs are shallow, but 'deep' grid reinforcement costs are recovered via locational TUoS that is in part funded by generators. In New York the construction of transmission for renewable generation is recovered on a 'beneficiary pays' principle, reflecting a deep connection cost for new generators, and some cost recovery from load serving entities if they are deemed to benefit on a Locational Marginal Price (LMP) load basis. The NYISO recognises that a new equation may be needed to identify the beneficiaries of a long-haul transmission line. In New York, the transmission operator receives tradable Transmission Congestion Contracts (FTR's) for new capacity, thereby providing a revenue source that can offset some of the transmission service charge.

Since incumbent generators do not have to pay for the long-run marginal cost of the transmission connections to the major load centres in the Australian markets, the energy prices themselves only reflect shallow connection costs. If a new generator in a remote

location has a marginal project, it may not be able to recover the full cost of remote connection to a load centre from the energy and renewable energy markets even though the combined investment may still be efficient in economic terms at the whole of market level.

The obvious and simple comparison would be of an incumbent and a new generator in the same location where the existing transfer capacity is fully utilised. If the new generator with the same costs as an incumbent had to pay the remote connection costs, based on the long-run marginal cost of transmission capacity to the load centre, to provide the new transmission assets when the incumbent does not, there is no way the new entrant can achieve a competitive return on investment. The only way a new entrant would be viable would be if its generation costs were sufficiently low enough to fund the incremental transmission cost.

This argument means that if remote generators are to compete on equivalent terms to incumbents, then the costs of remote transmission should not be imposed on remote generators unless it is also imposed on incumbents to the same extent so that the energy market price provides a basis for recovery of the remote transmission cost. In the special case where a remote generator enjoys a much lower energy cost taking into account emission impacts, there may be a case for that generator funding some of the remote connection cost to the extent that is financially viable, since that generator is thereby enjoying some of the benefits of the connection from higher gross profits before the transmission cost are deducted from income.

If a new entrant funds some or all of the remote connection assets, there is no firm property right that may be exercised over these connection assets to protect the benefits of the investment. To the extent that there remains spare capacity, the next party to connect to the network is able to free ride on this extension and only needs to pay for their own connection unless there are cost sharing arrangements in place. As a result, incentives exist for potential proponents of larger scale renewable energy generators to delay the development of their investment in the hope of free riding, at least partially, on network extensions.

The electricity market in Ireland manages this free-riding issue by using a 'gate system' for potential investments in wind generation to collect groups of connection applicants that satisfy predefined criteria. A connection plan is then developed based on the characteristics of the group, with a connection charge for each application based on their MW contribution of the group connection. This is similar to NERG proposal in the Australian context.

Investors in generation need to be confident that after paying for connection to the transmission network and any upgrades to the transmission backbone if required, their access to the system is not degraded due to further developments. They need to be assured of firm access and not face the threat of being constrained off in the event that another generator should connect to the system at a point in the network, utilizing assets that their initial generator has at least partially funded resulting in constraints developing

that reduces the initial generator's accessibility. Where property rights cannot be easily assigned, this exposure may be addressed by creating a new reference node at the connection point so that the generator may be able to hedge its exposure across the constrained transmission asset.

5.7 Regulatory solutions

Temporally and locationally efficient investment in transmission capacity, particularly to provide for remote renewable generation, may require a number of changes to the energy market frameworks. The following summarises potential options for further exploration:

- Extensions to the organised wholesale markets to provide additional revenue opportunities for entrepreneurial transmission investments:
 - Sub-regional nodal pricing to improve locational signals, and to provide trading opportunities that could fund transmission investment;
 - In introduction of tradable Financial Transmission Rights (in conjunction with nodal pricing) that can be assigned to owners of new transmission capacity, providing revenue opportunities that can assist investment, and alleviate some TuOS requirements;
 - In the case of the WEM market design, the consideration of a long-term forward capacity market, such as that explored by the NYISO, that assist future generation investment, and provide ex-ante capacity commitments that may assist transmission planning.
- The further development of transmission planning frameworks such that they provide for economic planning that is constrained not only to reliability objectives, but also environmental policy objectives; the assumption here, which should be explored, is that the CPRS and associated policy is introducing a new category of social objectives that may not be adequately represented in the proposed transmission planning approach. Could it be the case that remote transmission extensions may not be justifiable on economic or reliability grounds? This approach may therefore require the explicit accommodation of environmental policy objectives to ensure desired investment occurs. The assumption follows that transmission investment that may be needed to deliver environmental policy constraints is a social good, therefore perhaps warranting cost recovery on this basis. Many US markets are modifying their transmission planning frameworks to accommodate broader policy objectives related to the challenges of remote renewable generation; examples include New England, Texas and California.
- In the United States FERC Order 679 has provided scope for shared ownership and joint development of transmission projects. Following a beneficiary pays philosophy, the Order can explicitly link transmission ownership and cost recovery via an institutional and contractual vehicle that can provide a solution to the risk and cost allocation problem associated with long-haul extension of the grid to remote renewable generation regions. The Order provides for higher ROE, full cost recovery

for prudent costs, hypothetical capital structures, deferred taxation, accelerated depreciation, deferred cost recovery, and importantly shared ownership between mutual interested parties, including transcos, system operators and load-serving entities.

- FERC’s approval of California ISO’s (CAISO) proposal for a so-called “third” category of transmission facilities – for transmission trunk lines designed to access “locationally constrained” renewable resources -provides a means for fund transmission lines that do not meet reliability or economic tests in order achieve a different policy goal: encouraging the development of renewable resources. Under the approved mechanism, CAISO will initially include the costs of the renewable trunk line its transmission access charge; generation developers will provide a reimbursement over time as they interconnect. The reimbursement would be based on their share of the going-forward costs of the line at the time of their interconnection. The intent is for renewable generation owners who use the line to ultimately bear the cost of the line once the region’s renewable resource is fully developed.
- In Texas the legislature has required the Public Utility Commission of Texas (PUCT) to designate as Competitive Renewable Energy Zones (CREZ) areas in Texas with high-quality clean energy resources that require transmission to be built to allow access to load centers. Moreover, the law authorized the PUCT to order utilities to construct or expand transmission between the CREZ and load centers to help meet the Renewable Portfolio Standard (RPS) requirements (requirements similar to Australia’s RET scheme). Under this law, transmission investments are automatically considered ‘prudent’ and are funded by load.

5.8 New customer connections and location-based cost sharing

While remote area generators pay for the development of a generation connection node, the node would likely prove attractive to large load given the likely low transmission loss factors resulting in lower energy prices. The rules or arrangements should thus be sufficiently flexible to allow for a mechanism that enables the generators to recover the cost of the node development from customers when loads are connected and the radial extension becomes part of the shared network. The AEMC’s NERG proposal does not appear to anticipate a potential subsequent transfer of the revenue source from remote generators to beneficiary customers.

For remote area renewable generators, the ability to recover some of the transmission connection costs from customers could prove to be the difference between the viability of developing the remote renewable resource or making such projects unviable. Customers who benefit from the development of the transmission system to remote areas and accessing low cost, low emission energy could contribute to the viability. This can be achieved if the cost allocation arrangements recognise the initial development cost and provide generators or TNSPs with either a potential revenue stream from load customers that would offset the cost of initial connection and the development of the node.

Cost recovery options to provide transmission for remote renewable generation are numerous and varied. Many are based on whether transmission is considered a competitive alternative to generation, or whether is a pre-requisite, or enabler of competition between generation and load. The latter suggests that transmission has social good characteristics, and is associated with choices to socialise the cost of transmission, often on a postage stamp basis across load. The former suggests a 'beneficiary pays' approach may be more appropriate, with transmission costs funded by connecting generators and those loads that benefit. Cost recovery schemes that are consistent with this approach include locational TUoS that is shared between generators and loads, and that is also reduced by generator contributions for shallow or deep connection costs.

6 SUMMARY

In summary the key issues that need to be progressed include:

- The provision of information on the long-run marginal cost of alleviating the inter-regional and the main intra-regional constraints based on the cost of prospective augmentations and the impact of their need in relation to regional generating capacity and peak demand
- The provision of information on the value of the capacity of additional embedded generation at each major transmission node where local generation or demand side response is prospective.
- A regulatory approval process that values the benefits of a remote grid extension among local generators and local and remote customers having regard to the projected impact of the project on REC and energy prices.
- An inter-regional TUoS charging regime so that these benefits can be reflected in charges to customers across the regional networks according to the distribution of benefits, including through the impact of REC prices.

6.1 Generators

Generators need:

- Forward looking information on the long-run marginal cost of transmission augmentation related to specific constraints that would have a dominant effect on limiting generation output;
- An assessment of the value of embedded generation in the medium and long-term so that there can be efficient coordination of transmission, distribution and distributed generation and demand-side planning
- A process that values remote extensions and shares the risks with customers in an equitable manner based on a transparent risk analysis
- A mechanism to cooperate on developing share remote transmission extensions to new energy regions. The NREG proposal is a start in developing such processes, but it needs to consider customer benefits as well since not all the economic benefits of new generation are retained by generators.
- A mechanism to obtain firm access to new extensions to remote areas and across critical interconnections where they underwrite the deep connection costs.

6.2 TNSPs

TNPS need:

- An ability to earn higher rates of return on extension assets that have a higher risk of stranding than existing assets

- An opportunity to earn higher rates of return by deferring the equity returns on assets that have a deferred economic benefit profile
- A process to monitor the risk of stranded transmission capacity and the development of supplementary incentives to encourage reuse of stranded capacity where that maximises market efficiency.

6.3 Customers

Customers need:

- A process for inter-regional TUoS recovery that reflects the distribution of benefits from major augmentations to the main grid as well as large scale network extensions to the new energy regions where lower cost renewable energy is prospective.