29 September 2010

Mr John Pierce
Chairman
Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

Dear Mr Pierce,

Transmission Frameworks Review, Issues Paper

Loy Yang Marketing Management Company welcomes the opportunity to make a submission in response to the Australian Energy Market Commission's Transmission Frameworks Review, Issues Paper of 18 August 2010.

Loy Yang Marketing Management Company operates as the arm's length agent for Loy Yang Power, performing the energy trading functions and managing National Electricity Market regulatory and market development activities. Loy Yang Power is the largest single site privately-owned generator in the National Electricity Market (operating the Loy Yang A power station) and the supplier of coal to the Loy Yang A and Loy Yang B stations.

Loy Yang Marketing Management Company supports the objectives of the abovementioned review and note our primary concern is the nature of generation access to transmission and its impact on our ability to operate in the spot and forward markets underpinned by Loy Yang Power's physical generation assets.

Loy Yang Marketing Management Company endorses the Australian Energy Market Commission's view that transmission frameworks face a series of significant challenges moving forward. However, while these drivers present unique challenges, we contend that a large number of transmission challenges would remain in the absence of such policies as they do in other parts of the world. We hold this view on the basis that issues surrounding transmission have never been adequately resolved in the National Electricity Market.

In that regard, we believe the Transmission Frameworks Review represents a critical opportunity for essential reform to the way in which transmission services are delivered to market participants so as to secure capital and maximise competition and trade moving forward.

We seek your consideration of the attached submission.

Yours faithfully,

Jamie Lowe
Manager, Regulation and Market Development

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Submission in response to

Australian Energy Market Commission

Transmission Framework Review:

Issues Paper of 18 August 2010

29 September 2009

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Submission in response to:

Australian Energy Market Commission
Transmission Framework Review
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Submission lodged 29 September 2010 via www.aemc.gov.au.

Company Information

LYMMCo operates as the arm's length agent for Loy Yang Power, performing the energy trading functions and managing National Electricity Market regulatory and market development activities for Loy Yang Power.

Loy Yang Power is the largest single privately-owned generator in the National Electricity Market (operating the Loy Yang A power station) and the supplier of coal to the Loy Yang A and Loy Yang B stations.

In total, LYMMCo trades in excess of 2,200 MW which represents around one third of Victoria's electricity needs and more than 8% of the total generation for the south-east of Australia.

Contact Details

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Introduction

Australia, like other parts of the world, continues to focus on transmission arrangements as a consequence of the adoption of a liberalised energy market complemented by the separation of transmission and generation assets and investment decisions.

In recent times, in the National Electricity Market (NEM) there has been further focus on the transmission frameworks in the context of climate change policies. LYMMCo endorses the broad view that transmission frameworks face a series of significant challenges moving forward. However, while we concede that climate change policies are themselves drivers of some of the unique challenges currently confronting the NEM transmission framework we contend that a large number of these challenges would remain in the absence of such policies as they do in other parts of the world.

We hold this view on the basis that issues surrounding transmission have never adequately been dealt with in the NEM. This is in part a consequence of: the varied interests involved in the NEM's governance; the differing objectives of parties engaged in transmission governance and investment; the extent to which, in looking back, it is clear transmission is not routinely the most significant issue in the minds of interested stakeholders when compared with issues such as supply security and reliability; and the fact some active market participants, in particular in the Northern regions, have been less concerned with congestion to the same extent as private investors.

Nevertheless, at a time when the needs of consumers who rightly want electricity delivered to them at the times, and in the manner they value it, is likely to rely upon substantial investment in all stages of the supply chain,[1] it is fundamentally appropriate to ensure the short-comings in the transmission framework are identified and a forward looking approach to transmission is adopted to satisfy not only the needs of consumers, but also owners, operators and investors.

[1] Australian Energy Market Commission (2010) *Transmission Frameworks Review: Issues Paper*, 18 August, p.i.

Objective of the review

The AEMC commences with the proposition that the key objective of the Transmission Frameworks Review (TFR) is to "assess whether current transmission frameworks promote efficient outcomes across the supply chain".[2] In the context of the National Electricity Objective (NEO), as stated in the National Electricity Law, this means transmission investment and operation must be efficient and in the long-term interests of customers[3] based on competitive generation output and functioning distribution systems.

LYMMCo supports the TFR objectives and note our interest in the following issues addressed in this submission:

- determining the appropriate role of transmission;
- integrated nature of transmission frameworks;
- transmission planning;
- promoting efficient transmission investment;
- network augmentation driven by reliability standards;
- Regulatory Investment Test for Transmission;
- consequences of congestion;
- economic regulations of TNSPs;
- network charging for generation and loads;
- connection arrangements; and
- network operation

However, given LYMMCo's generation sector interests, our primary concern is the nature of generation access to transmission and its impact on our ability to operate in the spot and forward markets underpinned by Loy Yang Power's physical generation assets.

Key issues

Frameworks need to maximise commercial freedoms

LYMMCo suggests that an overarching consideration for the AEMC is allowing individual parties the commercial freedom to enter into the contractual and business arrangements that they feel maximise their economic benefits and incentives.

It can be argued the NEM framework has lost sight of the rationale behind its inception and is now driven by regulatory spheres of influence at the expense of maximising commercial and trade outcomes and in turn benefiting end users and market participants. This has led to a narrow conception of what constitutes an economic benefit and how such benefits can be delivered.

[2] Australian Energy Market Commission (2010) *Transmission Frameworks Review: Issues Paper*, 18 August, p.15.
[3] Biggar, Darryl (2009), *A framework for analysing transmission policies in the light of climate change polices,* p.5.

We see no reason why the NEM framework for transmission can not facilitate dynamic contractual arrangements that take precedence over regulatory outcomes across the spheres of connection, construction, and ownership of transmission and generation assets. This occurs throughout other economic sectors, including the electricity sector in other countries and should be facilitated in the NEM.

Role of transmission is not clear

Transmission networks function as the linkage between generation units, which convert primary energy into electricity, and distribution systems which connect the bulk of load, especially household consumers to electricity supply.

In other words, the practical role of transmission is to minimise the costs of electricity supply by allowing electricity produced with low cost fuel in one location to be consumed in another location. In the NEM, this occurs via individual generators, who are dependent upon transmission networks, competing on price, to ensure their electricity supply is delivered to those that desire it.

From this perspective, economic efficiency arises from ensuring sufficient transmission capability is available to enable use of lowest cost available power sources at the lowest cost.[4]

The issue confronting the NEM is how transmission facilitates this competition in the context of a decentralised market that does not have provision for central planning and does not consist of vertically integrated generation and transmission companies.

Sauma and Oren indicate that in the absence of vertical integration the coordination of investment across the supply chain is more complicated. They state:

> The vertical separation of the generation and transmission sectors has resulted in a new operations and planning paradigm . . . Planning and investment in the privately owned generation sector is driven by economic considerations in response to market prices and incentives. The transmission system, on the other hand, is operated by independent organizations that may or may not own the transmission assets.[5]

While the merits of a central planning approach, or the internal efficiency drivers of a vertically integrated transmission and generation monopoly may be worthy of academic consideration, they are not reflective of the NEM overarching framework. Therefore, we must ensure that the NEM paradigm is permitted to operate most effectively.

We contend, as it relates to the role of transmission frameworks within the NEM, these frameworks are not structured appropriately and the role of transmission, beyond its practical application, remains unclear.

However, given the short-comings of these frameworks have not had enduring effects on a large number of market participants, in part due to the second order benefits of significant customer reliability related investment in the Northern States,

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[4] Sun, Haibin; Sanford, Mark; Powell, Louie (2004) *Justifying Transmission Investment in the Markets* in Electricity Transmission in Deregulated Markets, Dec 15-16, Carnegi-Mellon University, Pittsburgh.
[5] Sauma, Enzo E. and Oren, Shmuel S. (2006) *Proactive planning and valuation of transmission investment in restructured electricity markets* in Journal of Regulatory Economics 2006, 30, p.359.

the NEM has been able to cope with these pressures thus far (despite the costs to affected generators and consumers).

LYMMCo's concern is that the impact of inappropriately structured transmission frameworks, from a generators perspective, may become more prevalent moving forward and have significant impacts on generation assets and may further deter private investment. In that regard, this is an opportune time to consider the benefits and short-comings of the current frameworks and outline a clear role for transmission.

Lack of clarity in the National Electricity Rules

The Issues Paper suggests that:

> The NEM currently operates under an "open" access system, where a generator's "right" to use the transmission network depends on whether it is dispatched by AEMO.[6]

We would contend that the Issues Paper expresses access in a manner which contrasts with the intention of a number of the provisions in the National Electricity Rules (NER), is not consistent with intentions at the commencement of the NEM and is not substantiated.

For instance, the Australian Energy Market Agreement provides a national approach to energy access as:

> The Parties note that third parties have legal rights for access to energy infrastructure services at transmission and distribution levels on reasonable terms and conditions that promote efficient operation of, use of and investment in the infrastructure by which services are provided, thereby promoting effective competition in upstream and downstream markets.[7]

We contend the above clause endorses legal rights of access on reasonable terms and conditions when investing in the NEM. Furthermore, there is nothing in the spirit of the above clause that suggests the terms and conditions of access on reasonable terms should be surrendered following an investment; but instead relate to the efficient operation and use of the infrastructure from which services are received. Clearly, a legal right for a third party to access infrastructure would have no value if upon gaining access the right to reasonable terms was automatically surrendered.

We also suggest that access arrangements identified in the Issues Paper conflict with the intention of a number of the provisions in the NER which provide the objective of access provisions is to ensure that the agreed level of access for existing generators and customers will not be reduced as a consequence of new connection (load or generation) to the extent that all facilities or equipment associated with the power system are in service

We note this perspective is reinforced by the content of the initial application for National Electricity Code Authorisation which provides for access at fair and reasonable prices for new entrants without encroaching upon the access enjoyed by existing generators.

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[6] Australian Energy Market Commission (2010) *Transmission Frameworks Review: Issues Paper*, 18 August, p.29.
[7] *Australian Energy Market Agreement*, as amended 2 July 2009

Notably, the term “open access”, has no agreed definition in the NEM, and is not contained in the NER. Additionally, the access regime as it was initially approved prior to the NER, comprised the National Electricity Code which at that time excluded market dispatch provisions (i.e. Chapter 3). Hence, linking access and dispatch is a relatively new concept. This concept received traction with Dr Tamblyn, for instance on 19 February 2009 as follows:

> In the NEM, no generator has a prior claim (“access right”) to scarce network capacity. Capacity is allocated to the generators who are dispatched, i.e. the mix of generator which meets demand at least cost given the available network. The allocation of rights to use the transmission network therefore changes every five minutes based on dispatch.

Hence, we conclude that the AEMC position on “open access” in recent years has not been appropriately substantiated or explored (which in itself has stymied considered thinking on the issue of transmission).

This is not to suggest that the NER provides for guaranteed dispatch but only that access, at some level, was intended to provide a degree of protection in the planning domain which has not been honoured and should be driven by commercial not regulatory requirements.

Nevertheless, we would agree with the general perspective, reflected by the AEMC, that the NER as currently drafted has failed to be implemented and has not provided generators with the level of surety desired.

Given this lack of surety, generator access to the Regional Reference Node (RRN) is strictly limited by the capability of the shared transmission network. This capability depends on decisions taken by Transmission Network Service Providers (TNSPs), given their responsibility for maintaining and investing in the network, those taken by the AEMO in its capacity as the market operator, and the decisions of all other parties (generators and loads) connected to the network. And this dependency on transmission is independent of the competitive price an affected generator offers into the market.

Generator access to transmission is too uncertain

Within the regional NEM structure, generator access, at a physical level describes the ability of a generator to transfer its output from its physical location to the RRN using the shared transmission network.

Physical access enables energy sales which in the NEM energy only market directly determine the ability of a generator to recover fixed and variable cost. In that regard, ability to forecast energy sales with a degree of certainty determines the ability of a generator to fund their ongoing operations and creates incentives to finance new investment.

Congestion, and the form of network constraints, is a significant factor in undermining this revenue certainty and distorting investment incentives. Views on the likely significance of congestion moving forward differ; however, LYMMCo believes the material impact of existing congestion on a generator’s operation already creates too much uncertainty. If this were to increase, in light of significant new investment or climate change policies, we contend this would fundamentally undermine the NEO.

Cause of congestion

A network becomes congested when its thermal or stability limits are reached on individual elements of infrastructure which make up the transmission network. In the NEM, when those limits are reached individuals generators are constrained from being dispatched (or constrained on in some instances) to alter power flows.

Congestion is driven by a number of factors. We divide these factors into dynamic and static factors.

The static factors represent congestion outcomes at a point in time that may be influenced by incentives or modified in the short-run but can not be readily removed. This includes operational decisions, bidding behaviour, maintenance and operation of the network, and market rules which impact on how congestion is managed but that do not ultimately remove that congestion.

However, these are not the primary drivers of congestion or its occurrence in the first instance. Primarily, congestion is driven by dynamic decisions that can not be readily changed in the short-run. These concern plant size, locational decisions, and network capability, namely:

- transmission investment decisions;
- generation investment decisions; and
- regulatory framework for transmission and connection.

In other words, the primary drivers of congestion are determined by business and regulatory decisions which, given the nature of the investment required to develop generation capacity, can not be easily amended or revised. As such, dynamic efficiency, which concerns the efficiency of long-run decision-making and market performance, in timeframes where infrastructure can be changed, is critical to ensuring congestion issues do not continue to arise. This does not mean existing congestion management cannot be improved; however, it does suggest congestion will continue to be an issue if long-run concerns are not resolved.

Consequences of congestion

The AEMC is correct in describing congestion as an occurrence where the cheapest mix of generation cannot be used to meet demand because of network limits on electricity flows. The consequences of congestion include:

- discouraging new investment and unnecessary or inefficient network investment;
- suboptimal management of trading risks;
- reduced efficiency due to the effects of congestion; and
- further inefficiencies that result from the “disorderly bidding” incentivised by the current market arrangements (which leads to an inefficient distribution of dispatch within a group of generators that are jointly limited by congestion).

In essence, putting aside the minimum level of congestion which reflects balance within an efficient network, congestion undermines the desired market outcome and does not best serve market participants or customers.

For generators, congestion threatens their ability to earn revenues in the spot market, and exposes generators to unfunded difference payments in the contract market and significant penalties in the ancillary services market, often outside the control or influence of such generators. We also suggest that over the longer term increasing network congestion undermines the incentives on new generators to invest and compete in the market. This is because:

- without an understood level of certainty with respect to service, especially as spare capacity on the network is used and congestion increases, there is uncertainty with respect to revenue and consequently recovery of investment costs is less predictable;
- for any investment there is little value in sourcing materials and inputs even where demand has been identified if there is no certainty that you can compete alongside your competitors;
- uncertainty arises if there is a risk that part of or an entire asset may be stranded due to congestion which arises from others' investment decisions; and
- given that generators can't disconnect and join another grid in another region, the biggest hurdle for investors is knowing once they have sunk their investment that they can compete in the wholesale contract market based on the full capacity of their plant alongside every other generator, when they want to make product available, in order to recover the costs of that investment.

Thus it can be conceived that the consequences of the current transmission framework undermine investment incentives and jeopardise existing asset operations.

Conceptual approach generator access and managing existing congestion

The NEO is 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.[8]

In order to achieve the NEO the NEM:

- should be competitive;

[8] Section 7, National Electricity Law

- customers should be able to choose which supplier (including generators and retailers) they will trade with;
- should facilitate access to the interconnected transmission and distribution network; and
- be non-discriminatory between location, fuel type and existing participants and new entrants.[9]

This occurs via:

- exchange between electricity producers and electricity consumers through the spot market;
- wholesale contract market operation to manage financial risk and encourage competition;
- price signals for future investment in generation and transmission[10];
- decentralised decision-making based on legitimate price signals[11]; and
- transparent provision of all necessary information in a timely manner.

Currently problems arise where:

- competition in the wholesale contract market may be reduced by preventing generators from competing with their full capacity - which creates stranded asset risk, reduces market liquidity and impedes risk allocation (even in the absence of congestion the potential risk of congestion remains ambiguous and creates an unwillingness to enter into contracts and therefore reduces liquidity regardless of whether or not that congestion binds);
- the NER do not encourage efficient, decentralised, and coordinated transmission and generation investment decision making through the competitive supply side of the NEM;
- generators are not provided with the full range of price signals at the time they are making their own investment decisions to drive dynamic efficiency and when congestion occurs operation decisions do not drive productive efficiency; and
- transmission investment fails to meet the needs of new and existing entrants, including there being no legal or economic incentive for TNSPs to invest in transmission that is primarily for the benefit of relieving congestion.

To resolve these issues we need to assess the manner in which investment decisions, operation decisions, and access to transmission decisions are made and how this satisfies the customer's interests.

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[9] National Electricity Code Administrator at http://www.neca.com.au/NEM/index.html

[10] NEMMC0 (2008), *An introduction to Australia's national electricity market*

[11] Biggar, Darryl (2009), *A framework for analysing transmission policies in the light of climate change polices.*

Discussion

Determining the appropriate role of transmission

Transmission needs to fill two sets of objectives.

1. Facilitate consumption – Fulfil its practical physical role of ensuring low cost energy produced in one location can be consumed in another to the determined reliability standards.
2. Facilitate production - Underpin the financial viability and bank ability of existing and new generation projects by providing a known base level of service at a known cost at time of connection for the life of the project.

To satisfy these objectives we support Biggar's approach that in the absence of a vertical integration, transmission frameworks must be concerned with three inter-related sets of policies. These are:

a) short-term operational decisions by generators and loads (dispatch efficiency, unit commitment etc);

b) long-term investment decisions for generators (location, size, type of plant); and

c) both operation and investment decisions by transmission networks (co-optimised with generation investment/operation decisions).

The role of transmission frameworks, therefore, is to ensure that appropriate mechanisms exist in appropriate timeframes to induce the correct behaviour by participants to facilitate consumption and production in the least cost manner determined in principle by the market. Possible mechanisms include price signals, contractual arrangements, regulatory arrangements and coordination processes.[12]

Going back to our view that congestion is driven by different factors in different timeframes, i.e. static and dynamic factors, this means transmission frameworks need to provide different time-based signals depending on which factor requires redress.

As it concerns short-term objectives, this includes facilitating appropriate bidding, to ensure correct price discovery, as generators and load seek to satisfy their operational requirements. For TNSPs, this means they need to face incentives to maximise operation availability and minimise congestion.

In the long-term, for generators this includes appropriately weighting decisions that impact on transmission use and ensuring that generators are able to invest with surety that they have ongoing access to transmission. For TNSPs, this requires a regulatory framework which rewards investment in the network that facilitates competition and meets the needs of investors.

For instance, while the NEM arrangements explicitly consider the reliability needs of consumers and are driven by the desire to minimise transmission investment costs, the needs of individual generators who drive wholesale competition are not explicitly

[12] Biggar, Darryl (2009), *A framework for analysing transmission policies in the light of climate change polices,* p.5.

considered. This imbalance, considering the asymmetric risks faced by generators should transmission not be available, seems inappropriate.

Promoting appropriate investment

We are concerned that the discussion regarding transmission inappropriately focuses on "total systems costs" as a proxy for minimising transmission investment. We make this point on the basis that facilitating competitive markets should be a key role for transmission in the NEM and if implemented correctly will deliver least cost energy to consumers. And this and not minimising spend on transmission assets is an appropriate objective of the transmission framework.

We are not suggesting overall investment at levels seen in recent years is not significant, but that levels of investment are not determined to meet the needs of parties reliant on the transmission system in proportion to the risks those parties face and their role in facilitating competition and least cost outcomes.

Notwithstanding this, in a general sense, the objective of facilitating competition may lead one to conclude that the social costs of overinvestment in transmission and the potential consumer exposure to high costs in the face of congestion is generally in excess of the social costs of underinvestment. And hence ex-ante overinvestment should be favoured in the face of uncertainty. Roh and Shahidehpour express a similar view on the basis of events in the United States and Europe.[13]

However, as with congestion itself, identifying the delineating line between what is and is not efficient investment is no simple matter. In the case of congestion, there exist clear distributional impacts.

For instance, Sauma and Oren noted that transmission expansions may benefit society as a whole through incremental mitigation of congestion but some parties may be adversely affected.[14] In general circumstances, the opposition to change is likely to be from the party that has an ability to invoke constraints and exercise transient local market power. LYMMCo has not examined the extent to which this applies in the NEM but considers it an interesting proposition.

The third criteria requires a system which optimises - to the extent possible in an environment which have sacrificed vertical integration efficiencies for increased competition and overall efficiency - transmission and investment decisions. In this regard, we see, for example, a role for the National Transmission Planner (NTP).

In any case, the existence of an efficient level of congestion, the presence of transient market power (i.e. the point at which someone sets price giving their position in the bidding stack), and the tension between under- and overinvestment in transmission are not unhealthy features of the NEM.

Likewise, notwithstanding our view that the NEM frameworks have suppressed commercial flexibility, the management of these tensions, primarily by the Australian Energy Regulator in a regulatory context is adequate. However, it is our contention that the transmission frameworks do not adequately provide the signals needed to

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[13] Roh, Jae hyung and Shahidehpour, Mohammad (2007), *Market-based coordination of transmission and generation capacity planning* in IEEE Transactions on Power Systems, Vol.22 No. 4, November, p.1407.
[14] Sauma, Enzo E. and Oren, Shmuel S. (2009), *Do Generation Firms in Restructured Electricity Markets Have Incentives to Support Social-Welfare-Improving Transmission Investments?* un Energy Economics, Vol 31, No. 5, p.7.

ensure the most efficient outcomes across the range of policy sets outlined by Biggar.

LYMMCo Position

We believe the frameworks governing electricity transmission do not allow for overall efficient outcomes, including the least cost total delivered energy, in accordance with the NEO.

We suggest that the role of transmission is twofold:

1. **Facilitate consumption – Fulfil its practical physical role of ensuring low cost energy produced in one location can be consumed in another to the determined reliability standards.**
2. **Facilitate production - Underpin the financial viability and bank ability of existing and new generation projects by providing a known base level of service at a known cost at time of connection for the life of the project.**

This can occur by developing mechanisms to take account of the following decisions:

a) **short-term operational decisions by generators and loads (dispatch efficiency, unit commitment, etc);**

b) **long-term investment decisions for generators (location, size, type of plant); and**

c) **both operation and investment decision by transmission network (co-optimised with generation investment/operation decisions).**

This is evidenced by a regulatory driven investment process which does not maximise competition and trade, or meets the needs of new entrant generation, allows for inefficient new entrant locational decisions to undermine incumbent generator business models, distorts hedging positions, creates TNSP investment decision dependencies which are not predictable, promotes inefficient bidding, and creates an uncertain investment environment.

Integrated nature of transmission frameworks

As stated, we do not believe that the currently inter-related frameworks provide for overall efficient outcomes. Specifically, we are not convinced that the levels of congestion can be forecast with confidence so as to not seriously jeopardise individual generators revenue and therefore impede hedging strategies. This is a consequence of both the limited obligations on TNSPs to account for the needs of generators in the manner they consider the needs of load, and the fact there is no identifiable service levels for generators.

At present, TNSPs fulfil a series of conflicting roles in the NEM and this leads to a situation where generators are dependent on service provisions from a set of organisations that are not structured or renumerated in the manner normally associated with service providers in the wider economy.

In our view, TNSPs, and particularly in the case of Victoria, appear to have an incentive to minimise costs of investment which inevitably leads to deferment or avoidance of projects which may otherwise directly improve services for generators and hence improve competitive outcomes and maximise trade.

While we note that informally TNSPs take steps to operate and maintain the network in the least disruptive manner, we do consider this is a consequence of appropriate incentives which formalise the desire to maximise asset capability and only marginally can be attributed to incentives to maximise availability.

We are concerned that as network congestion increases the impacts of TNSPs will pose more significant risks to generators, possibly to a greater extent in some jurisdictions than others.

In saying this, we are conscious of TNSPs responding to the environment in which they operate, and in that regard we support a fundamental rethink of the services TNSPs should deliver. We also support the facilitation of the competitive purchase of transmission services as an alternative to provision through existing monopoly TNSPs. The ability of participants to exercise commercial freedom and elect to provide, operate or construct transmission services would further incentive the transmission sector.

LYMMCo Position

We believe there is a need to thoroughly consider the appropriate future role of transmission in providing services to the competitive sectors of the NEM as it currently fails to satisfy participant requirements and does not support efficient outcomes.

This is evidenced by: the absence of clearly articulated criteria for a base level of service to generators; an inability for generators to have the transfer capacities documented in the connection and use of system documentation honoured in the absence of legal action; a generic and unqualified expression of the basis on which a generator can connect and expect access to the Regional Reference Node, including in the Issues Paper; a market which operates without defined levels of service available in a wide range of liberalised energy markets in other jurisdictions; and the ongoing uncertainty this creates for generators reliant on the goodwill of network planners and operators to relieve congestion which undermines revenue certainty.

Transmission planning

The Issues Paper examines transmission planning in the context of challenges for efficient network and generation investment. The Issue Paper commences by discussing two distinct points: first, the ability of TNSPs to plan for future decisions by generators and load; and second, TNSPs exposure to appropriate regulatory incentives and obligations to ensure efficient and timely investment in response to changing demands for transmission services.[15]

The first point was explored in Biggar's paper in which he enunciated a view that the transmission planner – whoever that may be in this instance – must indirectly determine which potential generation resources will be exploited and which will not.[16]

[15] Australian Energy Market Commission (2010) *Transmission Frameworks Review: Issues Paper*, 18 August, p.20
[16] Biggar, Darryl (2009), *A framework for analysing transmission policies in the light of climate change polices,* p.29.

The problem with this approach is that is implies a choice between two extremes: reactive planning – where the transmission planner waits for generation decisions to take place – and proactive planning - where the transmission planner makes de facto choices about future generator locations. We are not convinced these two extremes are sensible.

It can be argued that research indicates that social welfare is increased by proactive planning. This has parallels with the general perspective than overinvestment in transmission is likely to have smaller net social costs that underinvestment; however, neither argument supports proactive planning in the absence of strong market signals. Nor does it suggest where an investor chooses to locate a generator in a sub-optimal location that some degree of costs should not be associated with that poor decision. Likewise, it does not suggest that the market can not be enhanced by commercially driven transmission solutions.

In essence, for the NEM, it is not inconceivable to reinforce and augment the network based on the best available information provided by industry as part of an engaged National Transmission Planner (NTP) process; while at the same time ensuring generators who choose to locate in remote or inefficient parts of the network are required to face the costs that their decisions will additionally impose on the transmission network and adopt the commercial and contractual arrangements best suited to manage those costs.

A subsequent problem with the arguments for proactive planning and the analysis portrayed by Biggar can be found in the initial analysis of Sauma and Oren. In their paper, they theoretically tested proactive planning against a reactive planner and an integrated planner; the proactive model was characterised as a complete and perfect information game. To the extent that a proactive planner in the NEM could be characterised as a sequential game where all actions are observable to all players is open to testing.

However, the body of analysis which seeks to establish ways of recapturing the benefits of vertical integration - that may have been lost through separating generation and transmission ownership in liberalised markets – through proactive planning is in essence seeking to mimic central planning by comparing the net social benefits of a centrally planned model against a de facto planned model.

The problem with such a comparison is that it is biased towards a set of benefits available to a vertical monopoly that do not account for competitive benefits, are not sensitive to individual asset needs and crowd out commercial solutions. The question is: can we compare optimised generation and transmission planning in a paradigm that has since been established for the purpose of maximising the benefits of trade not minimising regulated costs? Should we not be identifying competitive outcomes and how those competitive outcomes can be maximised? I.e. would a defined level of service taken into account when planning the network improve competitive outcomes and therefore social welfare overall?

LYMMCo does not have the answers to these questions but encourages further dialogue and thought on these issues with the AEMC on the nature of these questions and the objective function we are seeking to satisfy as we plan the transmission network. We suggest if we are seeking to better facilitate consumption and production than the current framework may be unable to do so unless it maximises trade and the value of competitive benefits by providing generators with a defined level of service.

The second issue concerns the use of financial incentives. We endorse a review of the current frameworks and believe that TNSPs in general have benefited from greater exposure to market incentives. We suggest greater linkages need to be made between TNSPs investment decisions and impacts on generators in the form of lower overall exposure to congestion and specifically lower exposure at times of high demand require consideration.

Heightened Victorian concerns

It can be argued that in the Victorian region a generator's dependency on transmission further undermines certainty as there is a disconnect between operation of the network and planning the network. In our view, real time operation needs to match planning arrangements.

It is critical that planning of the network is consistent with how the network is operated in real time. It is inconsistent with both the NEO and the reliability standard to plan a network on the basis of a high probability of load shedding in the event of the failure of a single transmission element during periods of high (>30% POE) but not necessarily extreme (10% POE) demand conditions. There is also concern that consumers in Victoria have never been explicitly informed that in the event of a single transmission network element failure on a day of high demand rolling blackouts will be required to maintain the transmission network in a secure state.

What does the AEMC mean by inefficient congestion?

We support the AEMC's view that building out all constraints would be inefficient, but that clearly, network investment needs to occur to support the wholesale market. However, we do not believe at any stage what represents efficient congestion has been determined.

If the NEM was 99% congestion free this may be a satisfactory achievement overall. But what if that 1% of congestion impacted a single generator repeatedly over the course of high-demand days in the first quarter of each year? And what if that generator had originally located at that site as it had no congestion and the decisions of other market participants had given rise to this congestion? And what if, if not for that constraint, that generator would be dispatched as they are on balance one of the cheaper generators in their region? Depending on your perspective, such an outcome may or may not be considered appropriate.

LYMMCo Position

The transmission planning arrangements may be sufficient for customers but do not meet the needs and intentions of the market, especially generators. We do not believe the market was conceived with the intention of providing generators with uncertain access.

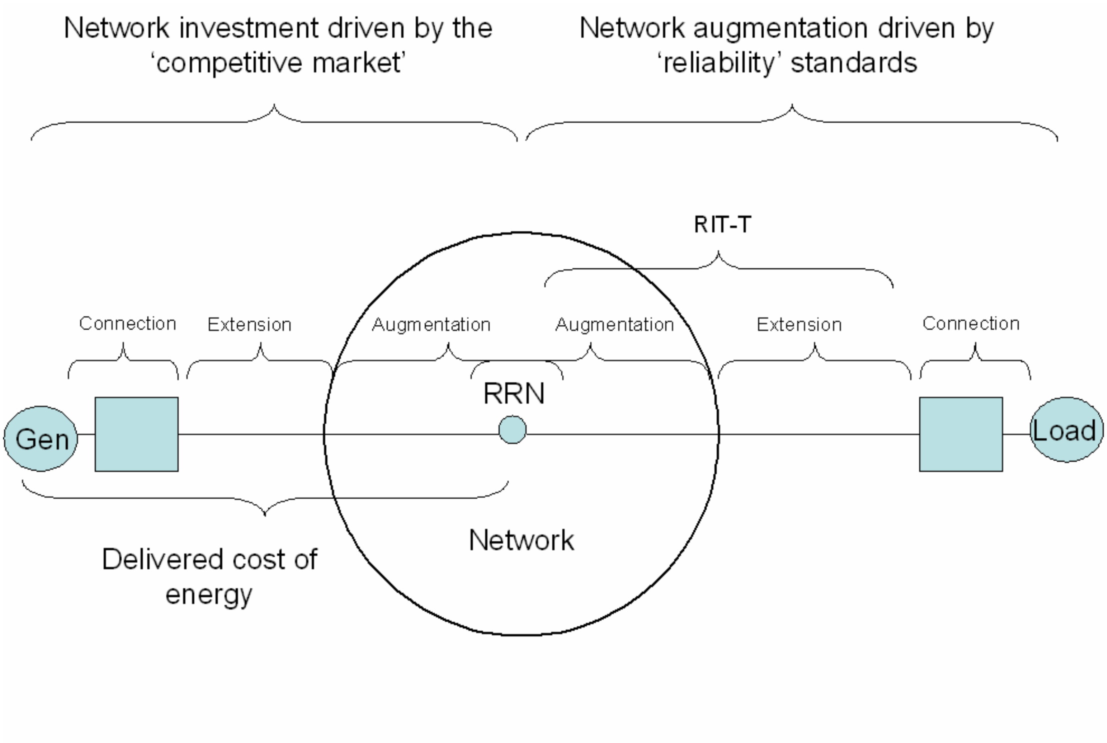
We believe there is scope to improve incentives and information for TNSPs given the uncertain planning environment. While we conceptually support the use of improved incentives we hold a number of concerns regarding the growing emphasise on proactive planning.

Promoting efficient transmission investment

Network augmentation is primarily driven by reliability standards and the competitive market. The current arrangements respond to requirements of customers in a different manner to the access arrangements for incumbent generators and for new generators.

This separation is represented in Diagram 1 below.

Diagram 1 – Investment framework



Network augmentation driven by reliability standards

As it relates to TNSPs, regulated investment in the network requires TNSP's to have the right incentives to operate and invest in networks over time. At present the incentives are created through regulatory obligations, and network charges. The regulated network framework is sufficient to meet customer needs in broad terms, although the inability of market participants to develop commercial solutions may be contributing to additional cost for customers.

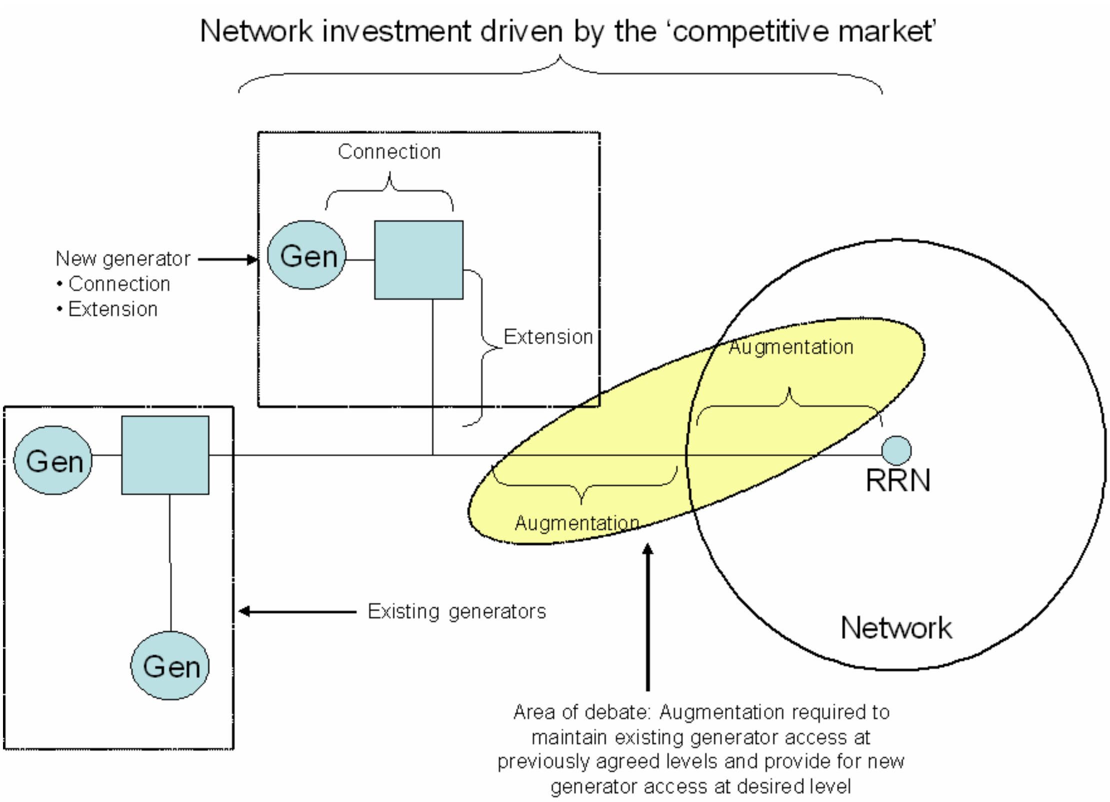
Regulatory Investment Test for Transmission (RIT-T)

While we believe the RIT-T plays a key role in justifying augmentation to the network for load customers, it provides a limited benefit in building out supply side congestion arising through the competitive market as it is an inappropriate tool for this purpose.

The AEMC over the course of recent reviews has identified that a rapid increases in generation investment under a emissions trading scheme (ETS) and the expanded renewable energy target (RET) may place new challenges on TNSPs in ensuring the timely supply of electricity to customers.

There is a view that the market framework including the NTP, the Last Resort Planning Power (LRPP) and the RIT-T will facilitate the development of market benefit projects in the future. However, the AEMC have previously questioned whether the NTP, LRPP and RIT-T framework will provide sufficient incentives for TNSPs to consider market benefits projects given the TNSPs overriding objective is to plan and develop the network to meet reliability obligations that are customer driven.

Diagram 2 – Augmentation requirements



Further, in developing the RIT-T the AEMC suggested that the introduction of more supply side driven congestion and new network flows from existing generation will lead to an increase in the need for the regulatory test to include market benefits to manage the added congestion, because using the reliability limb alone would be unlikely to address this congestion. The implication of this is that the AEMC considered that market benefits projects through the RIT-T are able to address supply side driven congestion. We do not share this view.

We note that with respect to intra-regional congestion:

- the primary role of the RIT-T is to select the least cost option from a number of alternatives to address customer reliability standards for inclusion of that project in the regulated asset base; however, with respect to intra-regional congestion any market benefits included in the assessment are likely to be negligible,
- the RIT-T does not have any direct role in the negotiated transmission access process (i.e. connecting new generators) nor is it used by new entrants in their decentralised decision making,
- the RIT-T can be gamed by generation investors to transfer transmission costs to consumers;

- by “early commitment”
- by “nearly committing” to influence a TNSP to include investment decisions

hence, relying on the RIT-T can support non-commercial behavior; and

- if the test is relied upon to address supply driven congestion the test can lead to the selection of inefficient generation and transmission investment.

For the above reasons we believe that the RIT-T cannot be relied on to efficiently manage supply side driven intra-regional congestion.

With respect to inter-regional congestion:

- the RIT-T (when evaluating inter-connector upgrades to avoid congestion), selects from a number of projects, the one that maximizes the net present value of the investment. A TNSP will apply a cost benefit analysis to a range of investment options (including demand side, market based generation and network based investments) to determine the investment option that maximises the net economic benefits to the market; and
- in undertaking these assessments the market benefits are primarily the deferred cost of generation investment. In this manner, the transmission investment is in competition with generation investment.

In our view, the recent reforms to the RIT-T improve the framework and incentives for TNSPs to meet their reliability obligations and incentives to better include market benefits to support economically efficient inter-connector investment at the margin.

However, it cannot be assumed that the current market framework for transmission planning arrangements including the NTP, LRPP and the RIT-T will facilitate the development of market benefit projects in the future to adequately deal with any material congestion that may arise from the introduction of an ETS and the expanded RET that impacts upon generation.

Hence, relying on the current RIT-T for transmission planning arrangements (that forces generators to rely on market benefits projects to build out material supply side congestion) creates an unacceptable level of risk for generators. Generators need certainty in the networks ability to deliver their product to the market.

Accordingly, we believe the issue of potential material congestion which acts as a threat to the major generation investments still needs resolution.

Options include, but are not limited to: resolving congestion concerns within the framework of facilitating connection; amending the RIT-T; or introducing a more generic test or standard for the purpose of facilitating competition and supporting new investment.

LYMMCo Position

While the RIT-T may act as an improvement on the earlier regulatory tests we remain concerned that it will not provide for efficient and timely investment in the shared network outside of customer reliability needs.

Outside the RIT-T, existing frameworks in the NER, for example 5.4A, should facilitate efficient and timely investment if they were applied as intended. However, ambiguity in their interpretation, an unwillingness to enforce these provisions, and a dogmatic interpretation of “open access” in recent years has

undermined their application. Hence, we support a detailed analysis of options for promoting efficient investment in the Options Paper.

Economic regulations of TNSPs

The current regime appears to broadly have the right incentives on TNSPs to operate and invest in networks over time for supply of network services for customers. Those incentives are created through regulatory obligations, and network charges. While LYMMCo agrees there is room for improvement we are not advocating wholesale revision as it pertains to reliability standards. In that regard, we struggle to justify the use of an ex post prudency test and would be concerned it may create perverse incentives.

As it relates to TNSPs services to generators we suggest there is greater room for adjustment in the regulatory framework so that both ex ante and ex post decisions better meet existing and new generators requirements.

LYMMCo Position

The current regime for economic regulation of transmission does not provide for efficient network investment from the perspective of existing generators and possible investors. This is because there are no guarantees that current TNSPs incentives lead to appropriate investment decisions and the efficient delivery of additional network capacity to support generation investment.

Network charging for generation and loads

The issue of whether generators should be charged for their use of the network is one that requires careful consideration and clear objectives.

We note the AEMC indicates that Chapter 6A of the NER provides that generators should not be charged costs associated with the transmission network. We also note that the Issues Paper indicates that the charging regime for generation can be characterised as “shallow” connection charging approach.

Although this is generally assumed to be the case the Issues Paper provides no evidence in support of this assumption. Some generators upon pursuing connection may be requested to pay for upgrades in infrastructure that will be utilised by a host of parties beyond their unique connection which is not consistent with shallow connection. Hence, as Biggar indicated “it is not possible to state definitively that the current charging policy in the NEM is inconsistent with such a policy of ‘deep connection charges’”.[17]

While academically insightful, it is not necessarily fundamentally relevant whether the NEM is currently best characterised as shallow connection or deep connection in one region versus another. LYMMCo contends that the objective of transmission charges – should they be preferred - should be efficient decision-making and given the nature of the TFR there is a need to develop a framework which best incentivises efficient decision-making moving forward in the timeframe where dynamic factors impacting upon congestion can be influenced.

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[17] Biggar, Darryl (2009), *A framework for analysing transmission policies in the light of climate change polices,* p.25.

On this basis, should the AEMC wish to develop a charging methodology to incentivise correct locational decisions we contend the following principles should be endorsed by the AEMC:

1. charges should be forward looking to impact on investment and locational decisions before they are made and not impact on sunk investments;
2. charges should have the singular purpose of informing efficient transmission decisions and not be used for the pursuing broader social objectives;
3. charges should be as granular as possible to reflect, to the closest extent that is possible, the direct impacts of an individual connections locational decisions and impact of the network;
4. charges should reflect the efficient cost of the network investment required to provide the defined level of service required by the new generator;
5. charges should be known at the time of connection and fixed for the life of the asset; and
6. defined service levels associated with network charges should be tradeable.

Given the objective of incentivising efficient locational decisions moving forward incumbents should not be charged a fee for their transmission usage as it not justifiable on efficiency grounds.

There are strong arguments which conclude that at the time of connection incumbent generators were themselves using sunk transmission assets with a marginal cost of use of zero and hence a move to charge incumbents, as some sort of historic penalty or for the purpose of providing comfort to new investors, would be disproportionate, undermine certainty and raise sovereign risk concerns.

Furthermore, the issue of recovering costs associated with sunk assets has been considered over the course of previous reviews and it would be inappropriate of the AEMC to reopen this debate.

There also appears to be a view (and we consider that this may be a consequence of a desire to promote climate change objective in tandem with transmission policy) that transmission charges, particularly variable charges, could be used to force retirement decisions.

We believe it is not in the best interests of the industry for these ideas to be promoted. Retirement decisions should be informed by competition within the market, generator business models and climate change carbon policies not transmission charges. Transmission charges, which would purport to incentivise a generator to turn off to avoid further charges, are not an efficient signal.

The third and fourth principles support an approach whereby, should a charging methodology be desirable, it should as is possible reflect an individual connections direct impacts on the network under assumed network operating conditions.

We understand that transmission investment is long-lived, characterised by significant scale economies and lumpy, since it needs to be undertaken in substantial increments. Hence, this principle may be difficult to implement in practice and may, depending upon the impact, require some level of smearing to customers where that augmentation is in the interests of the wider market.

However, this will not always be the case and in many instances it will be worth the private commercial benefit to the generator to pay charges or a charge that ensues from choosing that specific location (i.e. because the fuel source is highly valued) and the payment of those charges result in an efficient investment with a requisite defined service.

We also contend that the provisions of a defined level of service for new generators, pursuant to such a charge, and based on historical use of the network for incumbents, is a necessary pre-condition for a locational transmission charging regime, notwithstanding our broader support for defined levels of services regardless whether or not locational charges are adopted for new entrants.

This fifth principle reflects investors desire to know the risks and costs associated with an investment and bank the project on that basis. Hence, a single upfront or annualised fee should be available to the investor with appropriate optionality. For some plant, it may be sensible to pay a large upfront fee whereas other projects may benefit from annual fees with or without trade-offs on potential escalation factors. This will largely be dependent upon individual business models.

However, as a general rule, we do not support variable fees that change as network conditions evolve. The use of variable fees would be extremely problematic. In the main, merchant investors, and their financiers, require stability and predictability in policy, regulation and cost to facilitate investment in the NEM. Previously, the AEMC has indicated that stability, predictability and transparency are necessary factors in pricing regimes.[18]

Therefore, a variable fee which will change as network investment occurs and is subject to the effects of future generation investment does not provide stability or predictability. Interestingly, the Scottish Government noted that the use of variable charges can result in high charges which were unstable, unpredictable and highly volatile year-on-year.[19] We note that the National Grid does not consider this to be the case; however, the National grid did concede that there were legitimate concerns regarding transparency of pricing arrangements with this form of charge.[20]

Interestingly, we understand a variable charging arrangement existed in Queensland prior to the commencement of the NEM. We understand this type of model was abandoned and was not adopted at the commencement of the NEM as it was difficult to manage and was not stable[21]

Finally, it is our view that any defined service associated with this regime should be tradeable. The tradability of such service levels is valuable to existing and new generators. For instance, an existing base load generator could be incentivised to sell part of their defined service level at a market determined price should they commence winding down their operations or should they be willing to move to an alternative business model. In this paradigm, a new generator could therefore be exposed to a charge to augment the network and receive a defined service or purchase the existing defined level of service off an incumbent.

[18] AEMC (2006), *National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 No.22,* 21 December, p.2
[19] National Grid (2009), *Transmission Charging – a new approach*, May, p.30
[20] National Grid (2009), *Transmission Charging – a new approach*, May, p.23
[21] On 14 July 2009 NGF representatives asked the AEMC to provide qualification as to how a variable model differed materially from the Queensland scheme. To date no response has been forthcoming.

These principles, in our view, provide a sensible approach to charging for network access for new generators to promote overall efficiency. This does not mean we believe charging new entrants is the only available model to satisfy generator requirement for more certain access to transmission but it has merit and should be considered in the context of the Options Paper.

There is an alternative perspective that a long-run transmission locational signal is not a primary concern. From this perspective, it can be argued that the adoption of a clearly defined level of service for incumbent generators is not dependent on new entrant long-run locational transmission charges as a range of non-transmission locational signals already exist which drive dynamic efficiency. These include:

- price separation between regions;
- transmission losses;
- dispatch risk;
- connection charges; and
- fuel access and transport costs.[22]

If it is determined that these signals drive efficient locational decisions than the outstanding issue – from a investor perspective and for asset owners – is the viability of investments underpinned by the ability to negotiate a defined level of service at the time of connection that is maintained for the life of the asset. LYMMCo supports the exploration of defined service levels more generally in the context of the Options Paper.

LYMMCo Position

The objective of transmission charges should be: efficient decision-making moving forward in the timeframe where dynamic factors impacting upon congestion can be best influenced. Should the AEMC be minded to develop a charging methodology to incentivise correct locational decisions we contend the following principles should be endorsed:

1. **charges should be forward looking to impact on investment and locational decisions before they are made and not impact on sunk investments;**
2. **charges should have the singular purpose of informing efficient transmission decisions and not be used for the pursuing broader social objectives;**
3. **charges should be as granular as possible to reflect, to the closest extent that is possible, the direct impacts of an individual connections locational decisions and impact of the network;**
4. **charges should reflect the efficient cost of the network investment required to provide the defined level of service required by the new generator;**
5. **charges should be known at the time of connection and fixed for the life of the asset; and**

[22] AEMC (2008) *Congestion Management Review: Final Report*, June, p.19-20.

6. **defined service levels associated with network charges should be tradeable.**

If it is determined that a long-run transmission signal is not required to drive efficient locational decisions than the outstanding issue – from an investor perspective and for asset owners - which must be resolved, is the viability of investments underpinned by the ability to negotiate a defined level of service at the time of connection that is maintained for the life of the asset.

Nature of access

A framework for generator access to transmission

A framework for generator access to transmission that is consistent with the NEO should conceivably:

1. provide appropriate investor certainty;
2. support efficient decentralised commercial decision-making;
3. support location specific transmission investment;
4. provide funding for new transmission investment; and
5. ensure new transmission investment matches the preferences of new generation investment.

Investor certainty means:

- with a high degree of certainty to know or be able to forecast with confidence the cost of their access to the transmission system; and
- with a high degree of certainty forecast short run transmission costs and hence revenue. The short-run marginal cost of transmission is made up of congestion and losses, generators need to understand the extent to which the plant my have restricted access to the RRN due to congestion and as a consequence the extent to which their revenue may be curtailed as a result.

Support efficient decentralised-decision making means:

- generation investors face the true value of all the costs associated with a specific location which include:
    - the long-run and short-run fuel supply costs for that location;
    - location specific site costs such as, water, access and environmental costs;
    - long-run and short-run transmission costs for that location;
    - the ability to forecast with certainty the long-run transmission costs; and
    - the ability to forecast with certainty short-run transmission cost (congestion and losses) and the price duration curve to facilitate the forecasting of likely revenue and to assist in the selection of plant type.

Investors already face a short-run marginal cost transmission signal; however, this can conceivably be reinforced through exposure to an absolute long-run location specific transmission signal to be consistent with other location specific costs (which are absolute costs). Notably, the value of a location specific signals varies dependent upon the transmission framework, the range of potential solutions to resolve and the permitted ex-ante overbuild.

Ensure new transmission investment matches the preferences of new generation investment means:

- new generators have flexibility with respect to transmission access to match that access and cost with the size and nature and operation of their plant and know with confidence that this level of access will be provided over the life of the generation asset.

The tailoring of transmission access, which can be represented through augmentation costs can contribute towards building new transmission that matches new generation needs (while not having impacting on existing network users). However, again this is dependent upon the nature of any proposed reform.

Hence, all these elements combined produce a transmission access regime designed to maximise competition in the wholesale contract market, to support decentralised decision-making in the competitive supply-side of the NEM and ultimately benefit customers by satisfying the NEO.

Therefore, from a generators point of view, the essential features of an access regime are the ability to choose a level of access that will be provided at a known cost, with certainty, for the life of the plant. This will ensure that wholesale competition will be maximised and generation and transmission investment is made at least cost. These essential features are consistent with the NEO (and with the AEMC's proposal in relation to SENEs).

These essential features can be provided by either a combination of (depending on the variables and methods of implementation): a generic planning standard, a 5.4A type regime (associated with a recognised transfer capability); nodal pricing/financial transmission rights; a CSP/CSC regime; an augmented RIT-T and so on.

A matrix of a broader range of options and criteria against which they could be considered forms **Attachment A**.

Enhanced level of service versus base level of service

The Issues Paper flags the possibility of generators seeking an enhanced level of service. We remain unclear in what context an enhanced level of service can be provided without a base level of service being initially defined and seek clarification from the AEMC on this matter.

Furthermore, while we conceptually have no objection to a generator being able to seek an enhanced level of service, we contend that such an option only makes sense in an environment where:

1. a base level was defined, but that base level of service in all circumstances was to be so meaningless that it provided no benefits to generators. Such an

arrangement would represent an ongoing failure in transmission service provision; or

2. a centrally determined planning standard for generator service was adopted.

In both instances, it presumes that a generator can then arrange at the time of connection an "enhanced" known level of service for a known cost for the life of the asset. In such circumstances, the role of an "enhanced" level of service seems to be one off semantics.

This is because, the concept of an enhanced level of service becomes meaningless and by default becomes the revealed level of service that a generator requires and would seek at time of connection, under a range of known conditions, for the life of the asset.

For these reasons, we conclude that the value in defining an enhanced and base levels of service in an environment where the framework enabled generator's to select the level of service they require, or select no guaranteed service level, makes the concept of enhanced service as outlined by the AEMC relatively arbitrary.

We suggest the fundamental issue for consideration is how a framework can de developed, where upon connecting, the levels of service selected by generators reflects the nature of individual connection options (i.e. the type of line), the nature of the generator's business model, and the ownership and operation of the transmission asset.

LYMMCo Position

A framework for generator access to transmission that is consistent with the NEO should conceivably:

1. **provide appropriate investor certainty;**
2. **support efficient decentralised commercial decision-making;**
3. **support location specific transmission investment;**
4. **provide funding for new transmission investment; and**
5. **ensure new transmission investment matches the preferences of new generation investment.**

From a generators point of view, the essential feature of an access regime is the ability to choose a level of access that will be provided at a known cost, with certainty, for the life of the plant. This will ensure that wholesale competition will be maximised and generation and transmission investment is made at least cost. These essential features are consistent with the NEO and can be delivered through a variety of models.

We suggest that the difference between enhanced and base level of service in an environment where generator's can select the level of service they require or select no guaranteed service level makes the concept of enhanced service relatively arbitrary.

We suggest the fundamental issue for consideration is how a framework can de developed, where upon connecting, the levels of service selected by

generators reflects the nature of individual connection options (i.e. the type of line), the nature of the generator's business model, and the ownership and construction of the transmission asset.

Connection arrangements

LYMMCo has two issues of note with the current connection arrangements. First, relating to access, is that the connection process does not facilitate known access at a known price for the life of the asset. In that regard, the connection process does not account for wider market needs.

Secondly, the connections framework for generators in the NEM is challenging and ungainly. The lack of clarity in the NER around connection arrangements leads to inconsistent application of the NER provisions by TNSPs. As a result, connection parties find the process of negotiating connection and construction agreements can vary greatly between jurisdictions with timely and costly negotiations a common occurrence.

We believe it would be appropriate to review the operation of NEM connection arrangements to: improve clarity and consistency across jurisdictions; the allocation of costs; the operation of split responsibilities in Victoria; the timeliness of processing applications and enquiries; and the value of the existing dispute resolution arrangements.

LYMMCo Position

We have reason to believe the arrangements for connection of generators and by implication large end-users does not reflect the needs of the market either at time of connection or in minimising distortionary impacts on the market due to uncertain access post-connection. We support a review of the connection arrangements in conjunction with TNSPs and other affected parties.

Network operation

The NEM is likely to benefit from sharper incentives for TNSPs regarding their impacts on the market at an operational level as a result of their investment decisions. While we do not support an ex-post prudency test we do support further investigation of incentives within the Options Paper. It is our belief that incentive regimes have a net positive benefit on the culture of TNSPs and the services they provide when appropriately balanced against reliability, security and safety requirements.

Areas where the AEMC may wish to consider the use of sharper incentives include plant availability and reducing congestion. While LYMMCo has no firm position on the best approach available to improve incentives some level of exposure to congestion costs to the market, when controllable by the TNSP, and reviewing the appropriate amounts of revenue at risk, are worthy of consideration.

LYMMCo Position

The NEM is likely to benefit from sharper incentives for TNSPs regarding their impacts on the market at an operational level as a result of their investment decisions.

Dispatch of the market and the management of congestion

As it currently stands, with no prospect of regional boundary changes, there is no effective mechanism for managing the inefficiency that arises from inter-regional congestion in the NEM; the consequence of which is inefficient disorderly bidding.

We believe the implementation of an overarching congestion pricing mechanism which better supports settlement at the RRN should be investigated and is consistent with the regional model which we continue to support. This is likely to be a no regrets market wide enduring mechanism.

LYMMCo considers that such an arrangement should have the objective of ensuring that congestion does not occur or at least is managed at an "efficient" level. Noting that the existing management of congestion is largely inefficient and our support for a congestion pricing mechanism is based on the overarching belief it will be less inefficient overall and disincentivises current practices.

The AEMC has previously proposed exploration of the possibility of including a short term congestion pricing mechanism because "the long term G-TUOS charge may not signal all the short term inefficiencies caused by generator operational decisions"[23].

While we strongly dispute the value of the previously developed G-TUOS proposal we agree that any long-run signals that seek to better inform future locational decisions would have no impact on existing causes of congestion and hence, like existing locational signals, would have no impact on operational decisions because these decisions occur in a different time frame.

In this context, a congestion pricing mechanism will only address the mis-pricing issue that leads to disorderly bidding when congestion occurs, and will only improve productive efficiency at the margin. The gross inefficiencies that result from lack of transmission capacity will remain.

We remind the AEMC that this congestion has not been caused by generator investment or operational decisions but by inefficient access arrangements which do not provide investors with appropriate price signals or fund transmission capacity to support the new supply investment.

We, nevertheless, support a congestion pricing mechanism to address the disorderly bidding problem which can arise from both insufficient transmission investment and from transmission operational failures and maintenance outages as it is economically efficient.

Hence, we do not support the implementation of a time-limited congestion mechanism on the basis that congestion can be characterised as transitory, and therefore a pricing mechanism would only have application in those transitory circumstances. We note a location-specific scheme was trialled in the Snowy region and we endorse the AEMC's view this trial has limited applicability in the context of wider consideration of the merits of congestion pricing mechanisms across the NEM.

The distinction between transitory and enduring congestion is somewhat arbitrary. We would suggest the congestion can have an unpredictable life cycle across

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[23] AEMC (2009), *Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report*, 30 June, p.33.

network locations that are difficult to predict and can disappear and reappear as the network is augmented. On this basis, the need to make determinations about when and where a time-limited scheme would be implemented appears ungainly and creates uncertainty.

On that basis, while we agree that such an approach involves numerous implementation issues, a market-wide no regrets policy appears appropriate.

LYMMCo believes such an approach will better facilitate outcomes at the RRN and questions the objectives of parties who do not support better management of congestion and dispatch in the NEM.

LYMMCo Position

We believe the implementation of an overarching congestion pricing mechanism which better supports settlement at the RRN should be investigated and is consistent with the regional model. This is likely to be a no regrets market wide enduring mechanism.

LYMMCo considers that such an arrangement should have the objective of ensuring that congestion does not occur or at least is managed at an "efficient" level. Noting that the existing management of congestion is largely inefficient and our support for a congestion pricing mechanism is based on the overarching belief it will be less inefficient overall and disincentivises current practices.

Initial outline of possible models

The following section of the submission is not seeking to elaborate on the answers to the Issues Paper questions, but provide an indication of two possible models LYMMCo believes require consideration as part of the development of the Options Paper and by the Consultative Committee.

Participant funding v generator contributions v customer pays?

Debates around generator access to transmission generally focus on two issues: what a generator is given i.e. services, assurances, standards, and who and how payment for transmission is made.

Participant funding refers to funding models where connecting generators pay the cost of the upgrades required to maintain the integrity of the network following their connection. This is sometimes called a deep connection model. In its purest form participant funding models would not attempt to take advantage of economies of scale through complimentary funding from customers. However, participant funding models can be designed to do so.

Participant funding models provide the strongest locational signals, minimise stranded asset risks, and encourage decentralised decision making, but also can result in individual generators being tagged with large costs, which when not resolved has led to queuing problems in similar markets.

Generator contributions generally refer to a system where the charge paid by the connecting party does not relate to any costs associated with undertaking a specific upgrade of the network as a consequence of that connection. Generator contributions can take the form of annual charges or one-off upfront payments and alternatively can be structured to take account of the impacts of one's connection.

Generator contributions models provide weaker locational signals, as they are not reflective of actual absolute costs; however, they facilitate greater shared grid investment.

At their extremes, generator contributions and participant funding are quite distinct; however, in practice modified versions of either approach can provide very similar outcomes.

Customer pays models refer to a model whereby customers are directly responsible for funding the upgrades of the network (and in this instance beyond the scope of upgrades currently provided for in the NEM).

Defined Rights Model

Summary

- Strong locational signal (assuming AEMC deems a signal necessary)
- Limited scope for stranded assets.
- Explicit service level defined in connection agreement.
- Investor certainty guaranteed via defined right.
- Can be implemented as participant funding, generator contributions or customer pays.
- Provides strong locational signal and encourages decentralised decisions.
- Generator compensation regime administered by market operator.
- Defined service has value and provides an independent retirement signal.

The AEMC recently acknowledged that participant funding in the form of deep connection charges could provide greater certainty for existing generators in the face of possible congestion that would otherwise have been caused by a new entrant.[24] Therefore, it is correct to suggest participant funding models provide certainty to new investors, provide the strongest and clearest locational signals because they use absolute not averaged charges, support decentralised decisions, and minimise stranded asset risks for customers.[25] However, a corollary of the strength of the signal is that participant funding models are not as effective as generator contribution models in facilitating widespread grid investment and create additional, although not necessarily inefficient costs, for new entrants.

On this basis, the Defined Rights Model is an attempt to deliver the benefits of a participant funding model while overcoming the limitations of deep connection charges that result from issues of loop flows, lumpy costs and economies of scale that are better dealt with through a generator contributions model.

Hence, the Defined Rights Model could be implemented as either participant funding or generator contributions and has been set out below as if new connecting generators were charged a cost-reflective fee in instances where they connect in

[24] AEMC, September 2009, Final Report, Energy Market Frameworks Review in light of Climate Change Policies, p. 262.
[25] Concept Economics, September 2009, *Generator Access to Transmission*, pp. V, 41.

circumstances where there was or would be congestion as a consequence of that connection.

The aim is to promote dynamic efficiency and investor certainty by providing:

- agreed levels of service to network users paid for relative to the service agreed without delaying connection times;
- appropriate locational signals;
- a tradeable right of value at time of retirement; and
- a model which promotes the build out of congestion to support increased competition.

Under this model the transmission network is funded both by negotiated services for expansion of new supply and is regulated to meet reliability requirements for consumers on a cost of assets basis.

Service Definition for Transmission Withdrawal Points

Preferably, the transmission framework would allow generators to negotiate a level of service at a known cost for the life of the asset at the time of connection.

Service Definition for Transmission Injection Points

Under the model, all generators would have a registered capacity in MW as part of their connection agreements. The capacity would be determined by the generator. It would be published and fixed for the period of the agreement (usually the life of the plant or a sufficiently long period of time, i.e. 20 years). The network expansion that would be required to transmit this capacity would be determined for a specific set of conditions. For instance, these conditions could be:

1. all generation plant in service at the registered capacity;
2. all transmission plant in service;
3. forecast annual (50%POE) peak demand (it may be that another measure is used by the TNSP for transmission planning or another measure can be specified by the generator); and
4. optimised generation bidding[26]

so that no congestion would occur that would require any generator to operate below its registered output capacity. The expectation would be that the network can be expanded to simultaneously transmit all generators' registered MW.

These capacities may be traded between generators or new entrants at the "same" connection point, or, subject to network approval, another point where it is determined that that trade will release the required transfer capacity. This is necessary to avoid distorting retirement decisions.

[26] That is, generator bids are assumed to be entered such that each generator only just achieves the registered evacuation MW.

Generator Service Capacity Set-up

1. Where a new generator (or incumbent expansion) connects in a load-rich location and the capacity requested by the generator will be unconstrained post-connection, the generator will be registered to receive a service level at their requested capacity. There is no additional participant charge or generator contribution.
2. The same approach would apply to existing generators in such locations. Where no connection agreement already applies this could be determined through a review of historical congestion so that incumbents are provided with a service level equivalent to their historic access to transmission capacity.
3. Where a new generator (or incumbent expansion) connects in a subsequently congested area it will have the option to:
   a) be provided with a registered capacity at a service level just equivalent to the ability of the network immediately post-connection. This would receive no charge and mean the new connection would be utilising the spare transmission capacity on the network (an efficient outcome).
   b) negotiate a service level that cannot immediately be satisfied with the higher service level applying from the time of completion of a capacity augmentation. However, the generator would connect and compete for dispatch prior to the completion of augmentations. In order to receive the additional service level the connecting generator would be required to pay a contribution which reflects the new connection's additional use of the network.
   c) negotiate arrangements for part or all of the transfer capability of an existing generator at the "same" connection point/area (or a point agreed by the network). This would receive no contribution charge and mean the existing connection would be constrained-off in certain circumstances or choose to retire that existing plant.

5. For incumbent generators in partly congested locations, the following approaches could be taken:
   a) where an existing connection agreement already includes an evacuation capacity[27], this would become the registered evacuation capacity[28].
   b) where there is no existing listed capacity, a historical assessment would investigate the typical level of constraint that that generator had suffered in the specified conditions. The unconstrained volume would become the registered capacity.
6. For existing inter-connectors, the network would also identify an historic estimate of system normal capacity.
7. As available transmission capacity changes at any given unused point on the network the strength of the locational signal at that point will change to reflect the charge a new entrant would be required to pay at their time of connection. However, existing connections would not be negatively impacted.

[27] This is thought to be the case for all NSW and Vic generators in existence at NEM start.
[28] Presuming they can all be satisfied within the current network. If not, they would need to be pro-rata reduced.

Issues

A number of options for calculating this participant charge exist. The most successful option would be one that:

- required TNSPs to actively examine what options would be required to maintain existing and new generator output capacities;
- incentivised TNSPs to complete new works on time;
- would require new connections to pay a incremental charge based on their chosen location so as to avoid queuing issues and promote efficient locational decisions;
- allow TNSPs to access SENE style financing where economies of scale exist; and
- allow new users to lock in a cost at project start for the life of the connection agreement/plant.

An alternative is to use a pure participant funding i.e. deep connection charges; however, while LYMMCo supports the investigation of this option and believes it feasible, such a model would need to address queuing and first mover issues that arise due to lumpy costs (an issue that has been raised in the context of SENEs).

The question of whether there should also be payment by incumbent generators in return for this existing service is not an economic efficiency consideration but an equity consideration. As it would appear economic efficiency is not increased by charging sunk assets a fixed transmission charge related to location. Additionally, if transferability of output capacity is available, it is not required to promote efficient retirement (that does not undermine investor confidence). Note also that there is no readily available price as there would be for new assets.

An alternative to participant funding is generator contributions. LYMMCo opposes a centrally determined variable annual calculation methodology which by its nature will be volatile. Possible alternatives include:

a. calculate charges on an annual basis but lock in future charges to new generators at rate set at the year of their connection. Thereby providing investor certainty and accepting that any discrepancies between charges and costs will be recovered from consumers, which is not an inefficient outcome if generators have still been provided with an efficient locational signal; or

b. an approach whereby after a period of time, say 10 years, connection charges were refunded to the connecting generator. This will ensure that efficient network costs were still recovered from customers over the longer term; however, the immediate impacts of a locational signal were present at the time an investor is selecting a site and the locational charge, and the imposition of a sometimes significant charge, would be balanced against the other absolute costs. In other words the model would support decentralised decisions whereby the non-transmission benefits of a site could be deemed significant enough to carry the burden of a large transmission cost at that location.

The third funding option is that, if the AEMC does not believe locational signals are a significant problem due to the existence of other relevant signals, than customers could be called upon to fund the required level of investment. This could be achieved through modifications to the existing regulatory funding arrangements for TNSPs.

Operationalisation of the Defined Rights Model

The desired outcome is that generators continue to compete based on price and in recognition of the value of transmission a generator who generates in excess of their registered capacity who causes a constraint would compensate others who are constrained below their registered capacity.

Generator bidding and dispatch would be unchanged but a financial adjustment would occur post energy settlement (whether this occurs for every reason or only for transmission derived constraints needs to be resolved). Every binding constraint equation would trigger an adjustment such that each generator and interconnector that appeared in the equation was:

1. re-settled at the price relevant to that constraint; and
2. residues accumulated from (1) are re-distributed according to the product of each generator's co-efficient and its registered evacuation capacity.

This mechanism ensures constrained generators are financially exposed to the registered capacity regardless of their actual dispatch level and bid price. Incentives to bid below marginal cost (disorderly bidding) are removed.

When the registered capacity cannot be simultaneously satisfied for all generators (i.e. during outages) the mechanism would result in pro-rata short-payments below the registered capacities to all generators and inter-connectors in the equation. The adjustment is naturally balanced and mechanical. It is probably simplest to be performed by the AEMO on behalf of the network.

Transmission Service Incentive

The short payment that results when transmission outages occur provides an indication of the cost of that outage to the market. An incentive system, based on these short payments, could be developed.

Defined Planning Standard

Summary

- No defined service. Implicit service via planning against a defined standard.
- Investor certainty guaranteed via defined standard specified down to specific geographic zones.
- Can be implemented as participant funding, generator contributions or customer pays. Most suited to generator contribution or customer pays.
- No intended generator to generator compensation; however, TNSP could be made to face costs of congestion above the defined standard.
- Places value on implicit service level that can induce retirement.

The Alberta Government in its 2003 policy paper adopted the following position in relation to transmission services:

> *Transmission is the backbone of the electric industry. Transmission serves the public interest through delivery of reliable, economic electric power, as*

> *well as providing a platform for economic development and a competitive wholesale market. ...*
>
> *Transmission policy must contribute to a stable investment climate in order to maintain investor confidence and support continued capital investment in generation and transmission in Alberta. Alberta's transmission system is already congested because growth in electricity demand and investment in new generation facilities have not been matched by investment in new transmission facilities.*

In relation to transmission investment, the policy paper concluded:

> *Adequate transmission must be in place to support new generation. Transmission should not be a barrier to generation development - investors should be provided with certainty and confidence that transmission will be developed in a timely and adequate manner so that their product can be transported to market.*

Conceptually the Alberta Government's analysis has parallels in the NEM. However, criticisms of the Alberta policy, in the context of the NEM, suggest that the costs associated with a policy which supports building transmission for economic and competition reasons may be difficult to justify.

However, the total costs of upgrades needed in the NEM to provide an implicit level of service to generators would be relatively modest in the context of required generation investment of over $30b needed to meet Australia's energy needs going forward.[29]

On this basis, an economic policy which supports the construction of new transmission and underpins investor certainty and increases competition should be considered by the AEMC. The aim would be to maximise the value of trade and secure investor certainty by providing:

- anticipated levels of service to network users;
- appropriate locational signals;
- a model which promotes the build out of congestion to support increased competition; and
- consistency with the AEMC's approach to locational charges.

Under this model, the transmission network is regulated to meet reliability requirements for consumers and to meet a Defined Planning Standard for generators within a 'defined zone'.

What is a 'defined zone'?

The most notable difference between the Defined Rights Model and the Defined Planning Standard model is that the level of expected service is not referenced to the individual generator but reflects an aggregate level of service within a defined geographic area.

[29] Esaa (2008) *The impact of an ETS on the energy supply industry*.

Clearly, the more granular the definition the more beneficial it is to the individual generator. Conversely, the more granular the less logic there is in applying an approach which defines x% of congestion as the accepted standard. By this we mean that a Defined Planning Standard of, say 99% congestion free at the connection point of each individual generator, is a de facto Defined Rights Model.

Alternatively, a Defined Planning Standard based on regions is too broad and has limited benefit as it could lead to one or two generators facing the bulk of congestion through no fault of their own; a problem which exists in the current NEM framework.

Hence, a level somewhere between the ANTS zones and the node would appear to be appropriate. The work of AEMO in examining the national flow path may lead to a number of appropriate zones, likely in excess of the number of ANTS zones.

Service Definition for Transmission Withdrawal Points

A centrally determined, nationally consistent, reliability standard; this would need to be determined by market participants and the standard would need to be relatively high if it is to provide implicit levels of service to generators.

Service Definition for Transmission Injection Points

All generators will have a registered capacity in MW as part of their connection agreements. The capacity would be determined by the generator. It would be published and fixed for the period of the agreement. The network expansion that would be required to transmit this capacity x% congestion free within the "defined zone" would be determined for a specific set of conditions.

For instance, these conditions could be:

1. all generation plant in service at the registered capacity;
2. N-1;
3. forecast annual (10% POE) peak demand (it may be that another measure is used by the TNSP for transmission planning or as a measure can be specified by the generator); and
4. optimised generation bidding[30]

so that an agreed standard of x% congestion could occur that would require any generator to operate below its registered output capacity. The expectation would be that the network can be expanded to simultaneously transmit all generators' registered MW in the face of x% of congestion.

What is x%?

The Defined Planning Standard model presumes that it is economically beneficial and commercially appropriate for generators to expect to be able to operate congestion free in the majority of circumstances under set conditions.

[30] That is, generator bids are assumed to be entered such that each generator only just achieves the registered evacuation MW.

Therefore, the level of congestion one would expect depends upon the set of conditions one applies. In circumstances where the Defined Planning Standard is modelled against a high criteria, i.e. N-1 or N-2, 10% POE or similar, then a standard of for example 96% may be appropriate.

Conversely, where the standards were modelled against lower criteria, for instances, all transmission in service, 50% POE, than it may be appropriate to use a Defined Planning Standard of 99% congestion free under those conditions.

Generator Service Capacity Set-up

1. Where a new generator (or incumbent expansion) connects in an unconstrained part of the network, the generator will be registered to receive a capacity subject to the limitations of the Defined Planning Standard. No additional charges would be levied.
2. The same approach would apply to existing generators in such locations. This could be determined through a review of historical congestion so that incumbents are provided with a registered capacity equivalent to their historic access to transmission capacity.
3. Where a new generator (or incumbent expansion) connects in a subsequently congested area it will have the option to:
   a) be provided with a registered capacity at a level just equivalent to the ability of the network immediately post-connection subject to the Defined Planning Standard. This could receive no charge and mean the new connection would be utilising the spare transmission capacity on the network (an efficient outcome).
   b) accept registered capacity that cannot immediately be satisfied with the registered capacity applying from the time of completion of the augmentation to that meet the Defined Planning Standard.
   c) accept registered capacity that cannot immediately be satisfied with the desired registered capacity applying from the time of retirement of an existing generator (i.e. which could be induced by payment from the new connection to avoid generator contribution charges or from the TNSP to avoid augmentation costs).

4. For incumbent generators in partly congested locations, the following approaches could be taken:

   a) where an existing connection agreement already includes an registered capacity [31], this would become the registered capacity[32].
   b) where there is no existing registered capacity, a historical assessment would investigate the typical level of constraint that that generator had suffered in the specified conditions. This volume would become the registered capacity.
5. For existing inter-connectors, the network would also identify an historic estimate of system normal capacity.
6. As available transmission capacity changes at any given unused point on the network the strength of the locational signal at that point will change to reflect the generator contribution a new entrant would be required to pay at their time of

[31] This is thought to be the case for all NSW and Vic generators in existence at NEM start.
[32] Presuming they can all be satisfied within the current network. If not, they would need to be pro-rata reduced.

connection. However, existing connections would not be negatively impacted by new connections as the Defined Planning Standard would be maintained.

Charging arrangements under a Defined Planning Standard

Under this model new entrants would potentially face a charge dependent upon the zone they are in at time of connection.

LYMMCo does not suggest a centrally determined variable annual calculation methodology which, by its nature will be volatile, is appropriate. Possible alternatives include:

c. calculate charges for each zone on an annual basis but lock in future charges to new generators at a rate set at the year of their connection (i.e. charges were posted each year and applied to connections in that year did not impact parties that had already connected). Thereby providing investor certainty and accepting that any discrepancies between charges and costs will be recovered from consumers, which is not an inefficient outcome if generators have still been provided with an efficient locational signal; or

d. an approach whereby after a period of time, say 10 years, connection charges were refunded to the connecting generator. This will ensure that efficient network costs were still recovered from customers over the longer term; however, the immediate impacts of a locational signal were present at the time an investor is selecting a site and the locational charge, and the imposition of a sometimes significant charge, would be balanced against the other absolute costs. In other words the model would support decentralised decisions whereby the non-transmission benefits of a site could be deemed significant enough to carry the burden of a large transmission cost at that location.

Operationalisation of the Defined Planning Standard

The desired outcome is that generators continue to compete based on price and in recognition of the value of transmission the network is planned to ensure that congestion is limited to a Defined Planning Standard which generators are aware of at the time of their investment and which TNSPs will be required to maintain in the face of new connections.

Transmission Service Incentive

An incentive or funding model based on the available capacity within each defined zone and maintenance of the Defined Planning Standard should be explored in the Options Paper. For instance, while it is not conceived that the Defined Planning Standard would utilise a compensation regime between generators as is the case under the Defined Rights Model, the costs of congestion between the time of connection and the time of augmentation could be levied against the TNSP allowing the TNSP to balance the cost of meeting the standard against further augmentation costs.

Summary of LYMMCo responses to Issue Paper Questions

Question 1 Application of the NEO Do frameworks governing electricity transmission allow for the minimisation of total system costs and for overall efficient outcomes in accordance with the NEO? What evidence, if any, is there to demonstrate that this is or is not the case?
LYMMCo Position We believe the frameworks governing electricity transmission do not allow for overall efficient outcomes, including the least cost total delivered energy, in accordance with the NEO. We suggest that the role of transmission is twofold: 1. Facilitate consumption – Fulfil its practical physical role of ensuring low cost energy produced in one location can be consumed in another to the determined reliability standards. 2. Facilitate production - Underpin the financial viability and bank ability of existing and new generation projects by providing a known base level of service at a known cost at time of connection for the life of the project. This can occur by developing mechanisms to take account of the following decisions: a) short-term operational decisions by generators and loads (dispatch efficiency, unit commitment, etc); b) long-term investment decisions for generators (location, size, type of plant); and c) both operation and investment decision by transmission network (co-optimised with generation investment/operation decisions). This is evidenced by a regulatory driven investment process which does not maximise competition and trade, or meets the needs of new entrant generation, allows for inefficient new entrant locational decisions to undermine incumbent generator business models, distorts hedging positions, creates TNSP investment decision dependencies which are not predictable, promotes inefficient bidding, and creates an uncertain investment environment.
Question 2 The role of transmission Is there a need to consider the appropriate future role of transmission in providing services to the competitive sectors of the NEM? What evidence, if any, is there to suggest that the existing service provided to facilitate the market, or the definition of this service, is inappropriate or insufficient?

LYMMCo Position We believe there is a need to thoroughly consider the appropriate future role of transmission in providing services to the competitive sectors of the NEM as it currently fails to satisfy participant requirements and does not support efficient outcomes. This is evidenced by: the absence of clearly articulated criteria for a base level of service to generators; an inability for generators to have the transfer capacities documented in the connection and use of system documentation honoured in the absence of legal action; a generic and unqualified expression of the basis on which a generator can connect and expect access to the Regional Reference Node, including in the Issues Paper; a market which operates without defined levels of service available in a wide range of liberalised energy markets in other jurisdictions; and the ongoing uncertainty this creates for generators reliant on the goodwill of network planners and operators to relieve congestion which undermines revenue certainty.
Question 3 Transmission planning Does the current transmission planning framework appropriately reflect the needs and intention of the market (including generators, loads and demand side response)? Will this adequately provide reliable information to TNSPs on where and when to invest, or when to defer or avoid investment, in an uncertain planning environment, or is there a case that additional market based signals might be beneficial?
LYMMCo Position The transmission planning arrangements may be sufficient for customers but do not meet the needs and intentions of the market, especially generators. We do not believe the market was conceived with the intention of providing generators with uncertain access. We believe there is scope to improve incentives and information for TNSPs given the uncertain planning environment. While we support the use of improved incentives we hold a number of concerns regarding the growing emphasise on proactive planning.
Question 4 Promoting efficient transmission investment Will existing frameworks, including the recently introduced RIT-T, provide for efficient and timely investment in the shared transmission network?
LYMMCo Position While the RIT-T may act as an improvement on the earlier regulatory tests we remain concerned that it will not provide for efficient and timely investment in the shared network outside of customer reliability needs. Outside the RIT-T, existing frameworks in the NER, for example 5.4A, should facilitate efficient and timely investment if they were applied as intended. However, ambiguity in their interpretation, an unwillingness to enforce these provisions, and a dogmatic interpretation of "open access" in recent years has undermined their application. Hence, we support a detailed analysis of options for promoting efficient investment.

Question 5 Economic regulation of TNSPs Does the current regime for the economic regulation of transmission lead to efficient network investment? Do the incentives on TNSPs lead to appropriate investment decisions and the efficient delivery of additional network capacity?	
LYMMCo Position The current regime for economic regulation of transmission does not provide for efficient network investment from the perspective of existing generators and possible investors. This is because there are no guarantees that current TNSPs incentives lead to appropriate investment decisions and the efficient delivery of additional network capacity to support generation investment.	
Question 6 Network charging for generation and loads Is a price signal of locational network costs for generators required to promote overall market efficiency? Would there be any consequential impacts on transmission pricing arrangements for load?	
LYMMCo Position The objective of transmission charges should be: efficient decision-making moving forward in the timeframe where dynamic factors impacting upon congestion can be best influenced. Should the AEMC be minded to develop a charging methodology to incentivise correct locational decisions we contend the following principles should be endorsed: 1. charges should be forward looking to impact on investment and locational decisions before they are made and not impact on sunk investments; 2. charges should have the singular purpose of informing efficient transmission decisions and not be used for the pursuing broader social objectives; 3. charges should be as granular as possible to reflect, to the closest extent that is possible, the direct impacts of an individual connections locational decisions and impact of the network; 4. charges should reflect the efficient cost of the network investment required to provide the level of service required by the new generator; 5. charges should be known at the time of connection and fixed for the life of the asset; and 6. defined service levels associated with network charges should be tradeable. If it is determined that a long-run transmission signal is not required to drive efficient locational decisions than the outstanding issue – from an investor perspective and for asset owners - which must be resolved, is the viability of investments underpinned by the ability to negotiate a defined level of service at the time of connection that is maintained for the life of the asset.	

Question 7 Nature of access

Would it be appropriate for generators and load to have the option of obtaining an enhanced level of transmission service? Would this help generators to manage risks around constraints and dispatch uncertainty?

LYMMCo Position

A framework for generator access to transmission that is consistent with the NEO should conceivably:

1. provide appropriate investor certainty;
2. support efficient decentralised commercial decision-making;
3. support location specific transmission investment;
4. provide funding for new transmission investment; and
5. ensure new transmission investment matches the preferences of new generation investment.

From a generators point of view, the essential feature of an access regime is the ability to choose a level of access that will be provided at a known cost, with certainty, for the life of the plant. This will ensure that wholesale competition will be maximised and generation and transmission investment is made at least cost. These essential features are consistent with the NEO and can be delivered through a variety of models.

We suggest that the difference between enhanced and base level of service in an environment where generator's can select the level of service they require or select no guaranteed service level makes the concept of enhanced service relatively arbitrary.

We suggest the fundamental issue for consideration is how a framework can de developed, where upon connecting, the levels of service selected by generators reflects the nature of individual connection options (i.e. the type of line), the nature of the generator's business model, and the ownership and construction of the transmission asset.

Question 8 Connection arrangements

Do current arrangements for the connection of generators and large end-users reflect the needs of the market? To the extent that more fundamental reforms to transmission frameworks are considered under the review, would it be appropriate to revisit the connection arrangements?

LYMMCo Position We have reason to believe the arrangements for connection of generators and by implication large end-users does not reflect the needs of the market either at time of connection or in minimising distortionary impacts on the market due to uncertain access post-connection. We support a review of the connection arrangements in conjunction with TNSPs and other affected parties.
Question 9 Network operation Are more fundamental reforms required to financial incentives on TNSPs to manage networks efficiently and to maximise operational network capability for the benefit of the market? Should further options for information release and transparency on network availability and outages be considered?
LYMMCo Position The NEM is likely to benefit from sharper incentives for TNSPs regarding their impacts on the market at an operational level as a result of their investment decisions.
Question 10 Dispatch of the market and management of congestion Is there a need for material congestion to be more efficiently managed in the NEM?
LYMMCo Position We believe the implementation of an overarching congestion pricing mechanism which better supports settlement at the RRN should be investigated and is consistent with the regional model. This is likely to be a no regrets market wide enduring mechanism. LYMMCo considers that such an arrangement should have the objective of ensuring that congestion does not occur or at least is managed at an "efficient" level. Noting that the existing management of congestion is largely inefficient and our support for a congestion pricing mechanism **is** based on the overarching belief it will be less inefficient overall and disincentivise current practices.

<u>ATTACHMENT A</u> - Matrix of Models Criteria	NEM without DCC and no application of 5.4A	Deep Connection Charges (DCC) and application of 5.4A (compensation)	NERG	LMP; FTRs; CSC/CSP and variants without DCC (pro-rata allocation)	LMP; FTRs; CSC/CSP and variants with DCC	G contributions model (alternative G-TUOS)	Amended RIT-T (to build out intra-regional congestion)	AEMC G-TUOS Model – 2nd Interim Report
T LRMC allocation issues	N/a.	Yes.	Yes.	N/a.	Yes.	Yes.	N/a.	Yes.
Non-discriminatory pricing	No.	Yes.	Yes.	No	Yes	Yes.	No.	No.
Barriers to entry	Yes.	No.	No.	Yes	No	Variable but probable no.	No.	Yes.
Provides a credible long-term locational signal	No credible locational price signal. Relevant signals are not "priced".	Yes. Provides long-term cost signal which is locked in at project start.	Yes. Provides long-term cost signal which is locked in at project start.	No credible locational price signal. Relevant signals are not "priced".	Yes. Provides long-term cost signal which is locked in a project start.	Yes. Locational tariff provides a strong signal which is locked in a project start.	No. Not based on long-term signals to new entrants. Possible gaming by G must be managed.	No. Signal does not reflect absolute cost and is subject to unknown variation.
Provides investor certainty	No. T congestion costs <u>not</u> known for life of plant.	Yes. Transmission costs known for life of plant.	Only for connection. Transmission costs beyond connection <u>not</u> known for life of plant.	No. T congestion costs <u>not</u> known for life of plant. Threat of congestion negates benefit.	Yes. Transmission costs known for life of plant.	Yes. Transmission costs known for life of plant.	Improved subject to regulatory build out.	No. Transmission costs <u>not</u> known for life of plant.
Supports decentralised decision-making	No.	Yes. Investors face absolute costs.	No. Joint connections are not market driven but planner driven.	No.	Yes. Investors face absolute costs.	Yes.	No.	No. Does not reflect absolute costs over life of project or development of desired T assets.
Disorderly bidding solved	No	No	No	Yes. Provides framework.	Yes. Provides framework.	No	No	No

Criteria	NEM without DCC and no application of 5.4A	Deep Connection Charges (DCC) and application of 5.4A	NERG	LMP; FTRs; CSC/CSP and variants without DCC (pro-rata allocation)	LMP; FTRs; CSC/CSP and variants with DCC	G contributions model (alternative G-TUOS)	Amended RIT-T (to build out intra-regional congestion)	AEMC G-TUOS Model – 2nd Interim Report
Ability to forecast the impact of congestion on revenue[33]	No. Incumbents and new entrants subject to unknown impacts of future connections. Congestion relieve as consequence of RIT-T incidental to reliability requirements.	Yes. Incumbents and new entrants transfer capacity is assured in the planning domain.	No. G and new entrants subject to unknown impacts of future shared network connections. Congestion relieve as consequence of RIT-T incidental to reliability requirements.	No. Incumbents and new entrants subject to unknown impacts of future connections. Congestion relieve as consequence of RIT-T incidental to reliability requirements.	Yes. Incumbents and new entrants transfer capacity is assured in the planning domain.	Yes. Congestion, as a general principle, will be built out with a generator contribution	Variable. Generators subject to unknown impacts of future connections until regulatory decision to built based on amended RIT-T.	No. G and new entrants subject to unknown impacts of future connections.
Ensures new T investment can match preferences of new G investment	No. Constrains investment to available T capacity.	Yes. G can choose level of access.	No. Only applies to connection assets.	No. Constrains investment to available T capacity. Fewer inefficient locational decisions but LMP does not reflect all T charges. Needs to coupled with DCC	Yes. G can choose level of access.	Yes. G can choose level of access.	Variable.	No. Constrains investment to available T capacity.

Criteria	NEM without DCC and no application of 5.4A	Deep Connection Charges (DCC) and application of 5.4A	NERG	LMP; FTRs; CSC/CSP and variants without DCC (pro-rata allocation)	LMP; FTRs; CSC/CSP and variants with DCC	Generator contributions model (alternative to G-TUOS)	Amended RIT-T (to build out intra-regional congestion)	AEMC G-TUOS Model – 2nd Interim Report
Promotes wholesale market competition	Variable. At present minimal impact; but congestion undermines competition.	Yes. Provides greatest investor certainty through access to markets.	Yes.	No.	Yes.	Yes. Provides reasonable investor certainty through access to markets.	Yes. Assumes all congestion will be built out even if inefficient and at no cost to G.	No. Increases financial uncertainty as well as existing issues with congestion.
Decentralised decisions in generation only. (no dynamic efficiency)	Yes. But T uncertainties creates a barrier to entry.	Yes.	Does not facilitate market driven multiple connections.	Yes. But T uncertainties creates a barrier to entry.	Yes.	Yes.	RIT-T can be gamed and this may create uncertainty.	Yes. But T uncertainties creates a barrier to entry and G-TUOS charge a new unhedgeable risk.
Decentralised decision-making in generation <u>and</u> transmission. (dynamically efficient)	No. Creates barriers for G considering T investment at time of G investment.	Yes. Requires consideration of G and T absolute costs.	No. Only relates to connection assets.	No. Creates barriers for G considering T investment at time of G investment.	Yes. Requires consideration of G and T absolute costs.	Yes. Ensures consideration of absolute G costs and proportion of T costs.	No. Does not realise efficiencies which result from an investor facing the absolute cost or as close there to.	No. Does not reflect absolute costs over life of project.
Cost of access to T[34] **(excluding operational issues, credible outages and plant failure)**	Not possible to hedge against congestion, i.e. provides investors with revenue uncertainty and indeterminate access costs at time of investment.	Capacity defined in Connection or UOS agreement paid and maintained for life of the plant. Costs of access know with certainty at time of investment.	Connection costs only. Total costs of access determined by shared network regime.	FTR means it is not necessary for TNSP to build T if there is another source of revenue to fund FTR. However works best if coupled with some form of DCC.	Capacity defined in Connection or UOS Agreement paid for and maintained for life of the plant. Access costs know with at time of investment.	Capacity not necessarily defined; however, access costs known and locked in at time of investment.	N/a. Build out policy assigns cost to consumers.	No. Subject to an unhedgeable financial risk and an unknown future congestion risk.

Criteria	NEM without DCC and no application of 5.4A	Deep Connection Charges (DCC) and application of 5.4A	NERG	LMP; FTRs; CSC/CSP and variants without DCC (pro-rata allocation)	LMP; FTRs; CSC/CSP and variants with DCC	Generator contributions model (alternative to G-TUOS)	Amended RIT-T (to build out intra-regional congestion)	AEMC G-TUOS Model – 2nd Interim Report
Dispatch efficient	No. Results in inefficient dispatch due to congestion in the shared network. An additional CSC CSP would be required to address inefficiencies at the margin.	Yes. G are dispatched on the basis of their LMP, but because little congestion occurs there is no real variation from the RRP so receive RRP. An additional CSC CSP would be required to address inefficiencies at the margin (i.e. disorderly bidding)	No. Results in inefficient dispatch due to congestion in the shared network.	Inefficient dispatch due to congestion in the shared network remains. However, G receive CSP when generate above the CSC. (i.e. addresses disorderly bidding).	Yes. G are dispatched on the basis of their LMP, but because little congestion occurs there is no real variation from the RRP so receive RRP Yes. G receive CSP when generate above the CSC at the margin.	Yes. Generators are dispatched on the basis of their LMP, but because little congestion occurs there is no real variation from the RRP so receive RRP. An additional CSC CSP would be required to address inefficiencies at the margin.	Yes. Generators are dispatched on the basis of their LMP, but because little congestion occurs there is no real variation from the RRP so receive RRP. An additional CSC CSP would be required to address inefficiencies at the margin.	No. Results in inefficient dispatch due to congestion in the shared network. An additional CSC CSP would be required to address inefficiencies at the margin.
Dynamic efficiency –G face absolute LRMC location costs?	No. Probable inefficient operational outcomes and lack of T.	Yes.	No.	No.	Yes.	Variable.	No. Probable inefficient transmission costs.	No. Probable inefficient operational outcomes and lack of T.
LR/SR fuel costs	Yes	Yes	Yes	Yes	Yes.	Yes	Yes	Yes
site costs	Yes	Yes	Yes	Yes	Yes.	Yes	Yes	Yes
SR T costs	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
LR T costs	No	Yes	No	No	Yes	Variable	No	No

Criteria	NEM without DCC and no application of 5.4A	Deep Connection Charges (DCC) and application of 5.4A	NERG	LMP; FTRs; CSC/CSP and variants without DCC (pro-rata allocation)	LMP; FTRs; CSC/CSP and variants with DCC	G contributions model (alternative to G-TUOS)	Amended RIT-T (to build out intra-regional congestion)	AEMC G-TUOS Model – 2nd Interim Report
Ability to forecast with certainty LR T costs (revenue uncertainty)	No. Exposed to congestion.	Yes	No	No. Exposed to congestion.	Yes.	Yes	N/a.	No. Exposed to additional regulatory risk.
Ability to forecast with certainty SR T costs (dispatch uncertainty)	No. Exposed to congestion.	Yes	No	Improved.	Yes	Yes	No. Poor locational decisions still a risk, but will be built out more.	No.
Transparency of T framework	Poor.	High.	Outside NERG zone remains poor.	Poor for augmentations.	High.	High.	Poor. Subject to regulatory decision-making..	Poor.
Allocation of augmentation costs possible	N/a. Connection costs only.	Yes. Price band between incremental cost and stand-alone cost.	N/a. Connection costs only.	N/a. Connection costs only.	Yes. Price band between incremental cost and stand-alone cost.	Yes. Tariff based. Should reflect price band between incremental cost and stand-alone cost.	No. Augmentations not attributed to individual generators.	N/a. Connection costs only. Model does not provide specific augmentation to match G investment.
Can overcome scale effects/ realise economies of scale in network augmentation.	T investment is not occurring to support new entrants. Sacrificing competitive market efficiency.	Yes. Price band between incremental cost and stand-alone cost reflects share of an augmentation the TNSP/NTP elects to build.	N/a. Workable costing model but only applies to connection assets.	T investment is not occurring to support new entrants. Sacrificing competitive market efficiency.	Yes. Price band between incremental cost and stand-alone cost reflects share of augmentation the TNSP/NTP elects to build.	Yes. Tariff reflects share of an augmentation the TNSP/NTP elects to build on greater scale.	Regulatory planned model caters for realising T economies of scale (at expense of dynamic efficiency)	Regulatory planned model caters for realising T economies of scale (at expense of dynamic efficiency)

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