AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

20 February 2012

FROM THE OFFICE OF THE CHIEF EXECUTIVE OFFICER

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Mr John Pierce
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Submitted online

Dear ~~Mr Pierce~~ John,

Transmission Frameworks Review – Submission to AEMC's First Interim Report

We welcome the opportunity to provide our submission to the AEMC's Transmission Frameworks Review First Interim Report.

As you are aware we have identified significant investment challenges through many of our planning reports. Many of these will require a better approach to development of the national transmission network. As a result, this matter has been given a high priority by our Board.

In our submission we present our views on why we believe the transmission framework should change to enable Australia to meet these challenges in a cost effective manner. We propose the key characteristics required of the changed transmission framework and address the specific options put forward in the report.

The submission provides the rationale and evidence behind these views. We have commissioned further detailed modelling and will submit that in a supplementary submission.

If you have any questions about any matters raised in our submission please do not hesitate to contact David Swift on (08) 8201 7371.

Yours sincerely

M. Zema

Matt Zema
Managing Director and Chief Executive Officer

cc:

Attachments: Submission to AEMC's Transmission Frameworks Review – First Interim Report

SUBMISSION TO TRANSMISSION FRAMEWORK REVIEW FIRST INTERIM REPORT

PREPARED BY:	Corporate Development
VERSION:	1
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Contents

Executive Summary

A new national transmission framework

The transmission framework must change for Australia to meet its future investment challenges in a cost effective manner. In this submission, AEMO outlines the key characteristics of a transmission framework that combines competitive delivery of services with a national approach to network planning.

Signal investment with efficient pricing and congestion management: The National Electricity Market (NEM) must be improved so that it signals efficient investment in the right assets, in the right place, at the right time. Investors need appropriate tools to confidently manage congestion within a region and facilitate trade between regions.

Optimise nationally not locally: The transmission regulation and planning framework must optimise network development on national basis. It must deliver integrated energy transmission outcomes, such as a combination of gas and electricity infrastructure.

Focus on outcomes: Transmission businesses must be rewarded for meeting outcomes. Regulatory and planning assessments of new transmission investments must reflect the value placed on the delivered services by energy consumers and generators.

Acquire transmission services efficiently: Transmission planning and connection negotiations exhibit natural monopoly characteristics. However, new connections and significant network augmentations can be constructed, owned and operated by competitive providers. The framework must support the competitive provision of transmission services where possible to place downward pressure on rising transmission cost.

Towards a low carbon future

Australia is transitioning to low carbon technology at a time of immense change. Consumers demand for energy at peak times continues to grow but they are more conscious of their overall consumption. At the same time, international demand for Australia's natural resources, such as coal and gas, will drive up input costs.

Over the next 20 years the NEM will require up to $120 billion in new generation expenditure. An additional $20 billion will be required on transmission augmentation to connect and integrate this generation. This expenditure is in addition to the ongoing replacement and refurbishment programs of generation and transmission businesses.

The consequence of all of this will be further upward pressure on prices which have already increased because of higher network charges. A new framework that integrates investment in generation and transmission will manage cost increases to efficient levels, support Australia's continued productivity and international competitiveness.

Signal investment with efficient pricing and congestion management

To respond to the challenge of the transition the NEM must be improved so that it signals efficient investment in the right assets, in the right place, at the right time.

The current market design creates an incentive for generators to bid plant at the market floor price to ensure they are dispatched at times of congestion. The economic consequences of these actions are higher prudential costs for retailers in the short-term and increased risk for both generators and retailers in the long term.

Generators and retailers are also unable to manage existing and future intra- and inter-regional congestion risk created by the network. Investors need appropriate tools to confidently manage congestion within a region and facilitate trade between regions. This can be achieved with a well managed access regime which insures participants against congestion risk.

Acquire transmission services efficiently

Given the pressure to adapt and develop while minimising price rises, it is important that we acquire transmission services as efficiently as possible. Transmission planning and connection negotiations exhibit natural monopoly characteristics. However, new connections and significant network augmentations can be constructed, owned and operated by competitive providers. The framework should support the competitive provision of transmission services where possible to place downward pressure on rising transmission costs.

The current connection regime does not support the competitive provision of connection services, with some limited exceptions. The benefit of the competitive provision of connection related services approach is that generators can discover efficient connection costs, better manage their risks and identify the offer which best meets their needs.

Large network augmentations can also be delivered competitively. However, there are limited opportunities for the competitive provision of these network services.

The rewards for these augmentations must be commensurate with the risks involved. Appropriate returns can be provided for the provision of the network infrastructure with higher rewards for the provision of higher services.

Optimise nationally not locally

To deliver the most efficient response to the challenges of the future, Australia's transmission regulation and planning regime must optimise network development on national basis.

Gas will be a vital source of energy. The electricity and gas market designs will need to work together more effectively to send signals which deliver investment in the right locations. The framework for pipeline investment must be integrated with the development of the electricity transmission system. In southern Queensland and Northern NSW there are immediate plans to expand the existing transmission system to address supply requirements. These supply requirements can be delivered more efficiently with a combination of gas transmission pipelines and electricity transmission lines.

Wind will be the leading source of renewable energy in the next decade. Wind generation from different regions must be matched with efficient network development to meet the national legislated target at the lowest cost. The state-based approach to connection has already resulted in significant congestion in South Australia without associated transmission developments to support its integration into the NEM.

The jurisdictional approach to connection has resulted in reduced trading between regions and has limited competition for end users.

Focus on outcomes

To deliver efficient transmission services, transmission businesses must be rewarded for achieving outcomes.

The current revenue setting framework has not succeeded in containing electricity prices. The building block approach rewards businesses for building assets. Input focused jurisdictional redundancy standards also incentivise building new assets.

In contrast, an outcomes focused approach to transmission development in has resulted in significantly higher network utilisation in Victoria than in other NEM regions, and lower transmission price rises without any discernable consequences on network reliability.

The building block approach and redundancy standards need to change. Regulatory and planning assessments of new transmission investments ought to reflect the value placed on the delivered services by energy consumers and generators.

A comprehensive solution is required

Our submission builds on the points above and provides both the rationale and the evidence that demonstrates that change is needed and approaches that could be employed to deliver improved outcomes. The transmission framework needs to be redesigned with a combination of market, regulatory and structural changes to deliver efficient services to customers.

To assist the AEMC with their next stage of analysis, we propose a comprehensive set of measures outlined below and discussed in more detail through the submission..

Generators must have greater choice and decision making power in the provision of their connection services. The present negotiating arrangements with profit-motivated transmission asset owners must be replaced with a framework that supports the competitive provision of transmission connection. The NEM-wide implications of these arrangements require a structural change from the jurisdictional-based central planning model. An independent national network service provider must be introduced.

As the connection of a generator in one location affects pricing and dispatch outcomes across the NEM, the connection will need to be supported by a tradeable access rights regime to provide long term certainty for generation investment decisions.

Generators will want to invest where there are efficient locational signals and a consistent, cost-effective and timely connection process. These investment decisions will then be integrated into planning decisions for the national grid.

The service provider will contract with multiple asset owners to provide the physical infrastructure, which do not have to be limited to network solutions. These could include demand side, generation support services or gas transmission services.

These arrangements will be coupled with an outcomes focused revenue setting arrangement to replace the building-block approach. Higher rewards will be provided to network service owners for the delivery of services which will be coupled with lower returns for the provision of the network infrastructure. Replacement of existing infrastructure would be regulated by the national regulator.

1 Introduction

The National Electricity Market (NEM) has been operating for over ten years. There have been many reviews which have improved operational outcomes. Generation investment has been timely with no load shedding due to inadequate generation investment.

However, the past does not provide a guide to the future. Australia is transitioning to low carbon technology at a time of immense change. Consumers demand for energy at peak times continues to grow but they are more conscious of their overall consumption. At the same time, international demand for Australia's natural resources, such as coal and gas, will drive up input costs.

New generation investment will occur in locations which are currently not well supported by the network. This investment will be driven by the need to meet customer demand and energy policy initiatives to reduce carbon emissions and increase the share of renewable energy. This in turn will add to the already high congestion levels experienced in the market. That is, unless there is a better national framework.

This investment comes at a time when prices increases, largely driven by network charges, are affecting both residential and business customers with implications for the broader Australian economy. Ongoing price rises will remain a key issue as consumers continue to seek a better balance between the cost they pay and the services they receive.

To meet these challenges, the NEM needs to integrate the transmission planning, operations and connections processes with the markets operation. This will ensure that it is in the best position to meet the challenges presented by climate change policies, technological advancements and competition for investment dollars.

Australia must have a sustainable regulatory framework that efficiently signals new investments and utilises existing assets. It is also imperative that the framework encourages the right investment in generation and transmission in the right place at the right time.

This submission is structured in three parts:

- Section 2 describes the case for change. Where possible, AEMO has attempted to quantify the impacts of these deficiencies. Where the consequences are too difficult to quantify, AEMO has discussed the deficiencies drawing on economic principles.
- Section 3 presents AEMO's transmission framework.
- Section 4 addresses the AEMC's First Interim Report, commenting on each of the packages and minor changes proposed by the AEMC. AEMO has clearly noted which of the options it supports, does not support and which are considered to be interim steps towards a long term solution.

2 The transmission development framework needs to change

2.1 The energy market will face unprecedented challenges

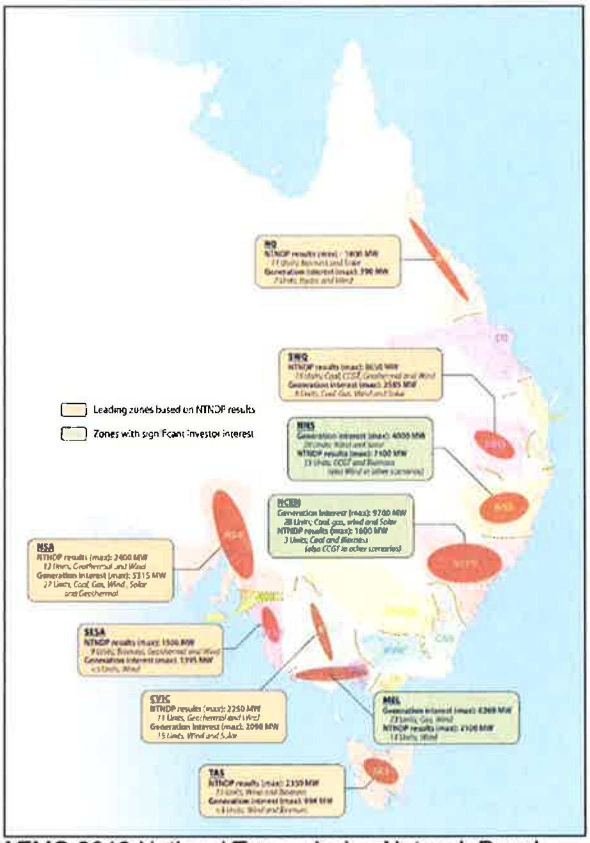
This Review comes at a crucial time in the evolution of Australia's energy markets. AEMO's modelling indicates that between $60 and $120 billion in new generation alone will be required by 2030 to meet this challenge. The Australian Treasury estimates $200 billion of new generation investment is required across Australia comprising $50–$60 billion in gas, $100 billion in renewables and around $45–$65 billion in carbon capture and storage coal plants by 2050[1].

The Investment Reference Group (IRG) suggested that investment in the electricity sector, including generation transmission, distribution networks, and pipelines and associated infrastructure, could exceed $240 billion by 2030[2].

The scale of these investment estimations is unprecedented in Australia's electricity supply history. The challenge will be to provide the right framework to ensure that the investment occurs in the right places at the right time and is supported by efficient and reliable development of the national transmission network.

The National Transmission Network Development Plan (NTNDP) highlights the likely location of generation investment over the next two decades will be in areas which are currently not well supported by the network. This includes South-West Queensland, Northern NSW, Central Victoria and Northern South Australia. This is highlighted in Figure 1 below.

Figure 1 - Identified and modelled connection locations



Source: AEMO 2010 National Transmission Network Development Plan

[1] Australian Government Treasury, *Strong growth low pollution: modelling a carbon price (SGLP),* Chapter 5 , July 2011

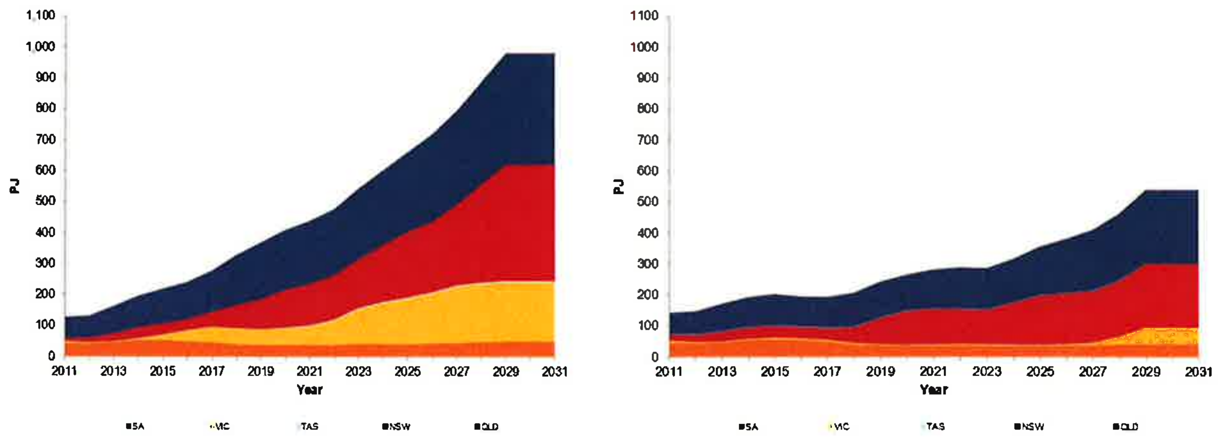
[2] Investment Reference Group, *A Report to the Commonwealth Minister for Resources and Energy,* p.4, April 2011

Australia will also experience unprecedented growth in the scale and importance of natural gas. Use of gas for Gas Powered Generation (GPG) in the NEM is forecast to grow by between 300% and 500% for the remainder of the decade. The reliability and security of the NEM will therefore become increasing dependent on the natural gas supplies.

Figure 2 below highlights AEMO's forecast GPG gas demand in its Decentralised World and Slow Rate of Change scenarios. By the end of the 20-year outlook period, annual gas demand for GPG ranges from 500 PJ to 1,000 PJ, depending on carbon price, gas price, and economic growth assumptions, a least a five-fold increase over current demand.

Figure 2 - Annual gas demand projections for GPG

a) Decentralised World scenario **b) Slow Rate of Change Scenario**



Source: 2011 AEMO Gas Statement of Opportunities Chapter 5

Future GPG demand is sensitive to carbon price, gas price and national economic growth. The 2011 Gas Statement of Opportunities (GSOO) indicates that the highest GPG demand occurs with moderate gas prices, moderate-to-high carbon prices, and moderate-to-high economic growth.

If gas prices rise significantly higher than current levels, studies indicate that low-to-moderate carbon prices are not sufficient to encourage GPG to displace higher emitting generation technologies.

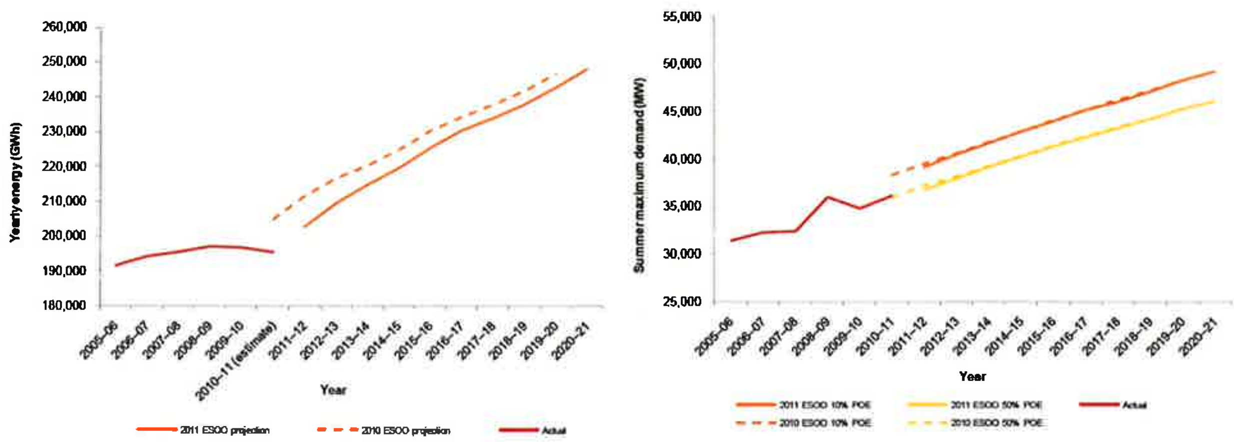
By lowering the gas price while holding electricity demand and the carbon price fixed, studies have shown that a substantially higher GPG demand trajectory is produced than when the gas price is higher.

Despite the domestic gas usage growth, the majority of gas production will be exported by the end of the decade. This has the potential to affect the price of gas and, ultimately, electricity. These effects can be moderated by having well functioning gas and electricity markets which support efficient investment and provide investment certainty together.

Given the locations and the energy transport challenges, an efficient solution would also incorporate the right mix of gas pipelines and electricity transmission.

At the same time, consumer demand for energy at peak times continues to increase. Peak energy, which drives new augmentations, continues to grow while the total energy demand across the NEM has fallen in recent years. This is because Australians are changing the way they use electricity. Figure 3 demonstrates that observations of electricity consumption patterns are showing significant changes in response to small-scale own-use electricity generation, such as rooftop solar Photovoltaic generation, expected increases in retail electricity prices as a result of network charges, the Clean Energy Future plan, energy efficiency schemes and new technologies such as plug-in electric vehicles.

Figure 3 - NEM Wide Energy and Peak Demand Growth



SOource: ESOO 2011

The effect of the growth in peak demand, but lower energy demand is an increase in the per-unit cost of electricity. To efficiently meet the needs of consumers, the market signals and revenue setting arrangements must encourage innovative solutions that match.

2.2 Toward an integrated transmission development framework

To meet these energy challenges the NEM requires a robust and integrated transmission development framework. The framework requires locational signals for generators and long term certainty, cost effective and timely connection arrangements. It also needs to be integrated with national planning arrangements and supported by regulated rewards for the delivery of services. These changes can be summarised as follows.

Signal investment with efficient pricing and congestion management: The NEM needs to be improved so that it signals efficient investment in the right assets, in the right place, at the right time. Investors need appropriate tools to confidently manage congestion within a region and facilitate trade between regions.

Optimise nationally not locally: The transmission regulation and planning framework must optimise network development on national basis. It must deliver integrated energy transmission outcomes, such as a combination of gas and electricity infrastructure.

Focus on outcomes: Transmission businesses must be rewarded for meeting outcomes. Regulatory and planning assessments of new transmission investments must reflect the value placed on the delivered services by energy consumers and generators.

Acquire transmission services efficiently: Transmission planning and connection negotiations exhibit natural monopoly characteristics. However, new connections and significant network augmentations can be constructed, owned and operated by competitive providers. The framework must support the competitive provision of transmission services where possible to place downward pressure on rising transmission cost.

The potential opportunities to improve the current framework are discussed below.

The economic consequences of the opportunities for improvement have been quantified where possible. AEMO has also engaged consultants to quantify these deficiencies which will be provided in a supplementary submission. However, a number of important consequences are difficult to model as they go to longer term dynamic efficiency, investor appetite and risk premiums. These matters are addressed with reference to their expected effects.

2.3 Signal investment with efficient congestion

2.3.1 The short term management of constraints can be improved

The NEM must be improved so that it signals efficient investment in the right assets, in the right place, at the right time.

It is economically acceptable to have some congestion in a network covering distances such as the NEM, as it provides signals for new investments. To alleviate all congestion would be uneconomic. However, there are occasions where the congestion is uneconomic.

The NEM market design and the interaction between the market and the network regulatory regime lead to outcomes which can drive participants to "disorderly bid". At times of congestion generators are incentivised to bid plant at the market price floor to be dispatched.

This disorderly bidding provides a false signal. It can create congestion and prices which do not reflect the underlying economic costs at times and on other occasions it can alleviate congestion that should rightly be signalled to the market.

The failure of the market to drive participants to disclose their efficient costs is a fundamental flaw. It increases the risks of operating in the market and can impact on dispatch, spot market prices, price volatility and the firmness of inter-regional settlement residues.

This inefficient management of congestion affects generators financially in an operational timeframe as well as their investment decisions in the medium and longer term.

AEMO has already provided examples of the effects of disorderly bidding in its submission to the AEMC's Issues Paper[3].

It has been argued that the occasional large price fluctuations and distorted spot market payments are in economic parlance primarily a "wealth transfer" or that the spot market outcomes are largely offset through financial contract payments. However, volatility has a significant real economic cost effect on a generator's ability to refinance its existing plant or construct new plant.

AEMO has commissioned modelling to make a closer examination of the issues and the flow-on impacts to long term efficiency which it will provide to the AEMC as a supplementary submission.

To encourage the right generation investments, investors need appropriate tools to confidently manage network congestion and its consequential intra- and inter-regional price risks.

[3] See AEMO's submission to the first Interim Report

2.3.2 Long term investment signals can be sharpened

The NEM presently provides some locational signals for new connecting generators. These include

- Regional pricing, based largely on state boundaries
- Marginal loss factors, which represent an adjustment to the price a generator receives to account for electrical energy losses
- Connection costs for new generators designed around a negotiating framework and which reflect the technical requirements on generators at the chosen connection point.

However, generators are not exposed to the true cost of congestion, both intra-regionally and inter-regionally and therefore the investment signals are muted.

While there are price signals to incentivise generators to connect to the network in the most appropriate region, those price signals do not discriminate within a region other than the differences in marginal loss factors. However connecting generators still need to include the expected effects and cost of potential intra-regional congestion on their proposed investment. The congestion they face is likely to have serious ramifications for their dispatch and ability to meet their contractual positions.

The only option currently available to project proponents is to use the available congestion information from the market and network planners. The provisions encapsulated in Rule 5.4A have never been applied. Investors are unable to purchase capacity in any form of instrument to mitigate this risk. This increases risks of making investment decisions and can distort investment decisions as participants opt for lower capital and less risky investment options.

Long term investment certainty in the NEM is therefore threatened by the inability of investors to manage their congestion risk.

Examples of this are already occurring with the recent change in the location of new connecting wind generators. AEMO's 2011 Electricity Statement of Opportunity (ESOO) identifies 15,000 MW of wind generation projects in the NEM in the advanced and publicly announced status categories. The majority of these proposals are now in New South Wales due to policy changes in Victoria and penetration levels in South Australia. While some of it results from improved low-wind speed wind turbines, the majority is as a result of the prevailing congestion between South Australia and the rest of the NEM[4]. The consequence of this congestion is affecting the financial viability of all existing generation in South Australia and will reduce new base load generation proposals in South Australian region.

Dynamic efficiency would be improved if prospective generators faced efficient locational signals and were able to obtain more certainty on the congestion costs they face at a particular location. To better understand the benefits of providing generator certainty AEMO has commissioned work to compare the differences in the outcomes under the prevailing transmission framework with a framework that allows generators to negotiate a tradeable right. This will be submitted as a supplementary submission.

[4] ESOO 2011, p. 8-4

2.3.3 Clear linkages are needed between the connection of new generators and the development of the grid

The current connection negotiations focus on meeting quality of supply technical standards and the cost of the shallow connection. There is a very loose association between a generator's actions to negotiate and implement a shallow connection and action to efficiently augment the network in response.

The Rules establish a network planning framework which is intended to identify impending network congestion and determine through the regulatory investment test for transmission (RIT-T) whether it is efficient to augment the network to mitigate a rise in congestion or not. There are a number of flaws in the scheme, the most serious of which are that:

- The network service providers undertake planning annually and by general practice have only applied the test on the basis of committed generation developments
- The planning process and regulatory investment tests have generally been driven by intra-regional reliability standards. The justification of augmentations based on the optimisation of net market benefits delivered are extremely rare
- Whilst the Rules establish annual planning reviews by network service providers, their investment in the network is actually driven by the five yearly regulatory reset cycle making them less responsive to congestion which appears unexpectedly as a result of generation investment, and
- A decision to invest was made by the generator at a time when they could not be confident whether any action to augment the network would be justified as a result of their connection and without them facing the full locational pricing signal.

If generators faced the full cost of locating at a point on the network, they have the incentive to make a more efficient locational decision. If the payment of connection costs provided a right of access this would significantly reduce the project risk and allow the project proponent to internalise the cost of congestion on the project. If the provision of the rights drove an immediate response to expand and adapt the network to meet the needs of the connecting generator, they would have established a clear linkage between the connection of generators and the development of the overall network.

The period of significant change and the development of new generation precincts in the NEM require a clearer link between generation investment and the related network investment.

2.4 Optimise nationally not locally

2.4.1 No party is accountable for the national grid

Good governance requires allocating clear responsibility and accountability to an individual or party. Responsibility is defined as an obligation to carry forward an assigned role or function, while accountability is defined as the state of being liable for something within one's power, control, or management.

Each jurisdictional planning body has been assigned clear responsibility and accountability to maintain the reliability of transmission networks within its region.

However, there is no party responsible or accountable for maintaining a national grid, through the development and management of national flow paths. This problem has been recognised in a number of previous reviews.

For example, in the 2002 Parer Review it noted there was a lack of integration of transmission network planning throughout the NEM. It attributed the problem to the following

- current transmission planning is undertaken on a regional rather than NEM-wide basis,
- a real or perceived lack of independence in planning processes dominated by incumbent TNSPs[5]

It also highlighted the problems created by the competing commercial priorities within the then existing Inter-regional Planning Committee (IRPC)[6].

Similarly, in 2007 the Energy Reform Implementation Group noted[7]

> While the current level of transmission investment is reasonably appropriate, investment decision making is biased toward investment within each state rather than, where it is efficient to do so, having a true national character. The lack of clear incentives or mechanisms to ensure the efficient ongoing development of the national transmission system leads ERIG to the conclusion that opportunities for efficient investment opportunities have been missed in the past.

More recently Garnaut noted[8]

> It seems unlikely that a seamless national network can be built by five state-based transmission planners with parochial responsibilities.

He continues with

> I recommend instead that the National Transmission Planner assumes all National Electricity Market transmission planning. This requires each state to separate its transmission ownership from its planning. The Victorian experience shows that the separation is feasible, and has advantages.

There are numerous examples which highlight the problems caused by this lack of accountability, including the South Australia – New South Wales Interconnector, the South Australian Interconnector de-rating investigated by the AER in 2009, and the ongoing limitations affecting Murraylink's transfer capability.

In the case of the latter at the time of conversion of the Murraylink Interconnector in 2004 supporting works were required in Victoria and NSW to ensure its optimal performance. However, there was no mechanism by which the ACCC could compel the jurisdictional planning bodies in those regions to undertake those works, which would deliver national benefits. To date, communication equipment in NSW to support the operation of the run-back schemes has still not been installed leading to reduced capability of Murraylink.

AEMO's work on NEMLink also highlights the potential benefits of better integration between national and state planning. There are some regional projects being considered by state-based transmission network service providers (TNSPs) which could be deferred or avoided. For example, an extension of the Sydney 500 kV ring network has been identified as an area where some of these benefits might accrue. However, the delineation in responsibility between the

[5] Commonwealth of Australia, Towards a truly national and efficient energy market, 2011, p. 125

[6] Ibid, p. 126

[7] Commonwealth of Australia, Energy Reform: The Way Forward for Australia, A report to the Council of Australian Governments by the Energy Reform Implementation Group, 2007, p. 12

[8] R. Garnaut, Transforming Electricity Sector Update Papers 2011, No. 8, p. 34

regional and national planning will inhibit the development of national transmission projects with a true national character. That is not to say that NEMLink needs to be built today. Rather, best practice planning requires a strategic direction of the national grid, which needs to be incorporated into short-term transmission expansion decisions.

The consequences of this lack of accountability are most evident in the 'firmness' of interconnector capability. As outlined in the appendices in AEMO's submission to the Transmission Frameworks Review Issues Paper interconnector capability is affected by constraints and amplified by disorderly bidding within regions and remote from the boundary. This suggests that the accountability cannot be limited to the physical transmission lines that cross the state boundaries[9].

2.4.2 The electricity and gas transmission frameworks do not interact and lead to efficiency losses

In the case of gas transmission, investment in most locations is driven by customers, or foundation shippers, who were prepared to pay the cost of that investment in return for some form of right. In this case the control and decision making is with the customer. However, it is the customer who also wears the cost.

In contrast electricity transmission expansion decisions for a generator do not entitle that generator to a right to use the service, even though the generator may be required to pay for that expansion.

The two regimes are very different and yet in a number of key areas of the NEM, gas and electricity transmission are in direct competition. Those inconsistencies may be leading to a significant loss of efficiency.

Examples of this inefficiency can be found in the Surat Basin and Northern NSW, where generators are locating close to the fuel source, rather than the existing transmission network. This results in a significant efficiency loss, and highlights the need for sharper signals in the NEM.

The 2011 NTNDP compares the cost differences between using a gas pipeline to deliver gas to a CCGT plant near a load centre, with using electricity transmission lines to deliver electricity from a CCGT plant. The study shows that under most circumstances, gas transmission pipelines are more economically efficient over large distances than electricity transmission.

Based on indicative costs from publicly available information, the cost of long distance transmission (100 kilometres, 250 kilometres, and 500 kilometres) to supply gas to generation close to a load centre is approximately half the cost of supplying electricity to a load centre from generation close to a remote gas source. For example, over a distance of 250 kilometres, the cost of building gas pipelines ranges between $150 million and $305 million whereas electricity transmission lines will cost between $350 million and $480 million, a 3 to 1 difference.

2.5 Focus on outcomes

2.5.1 Planning standards focus on redundancy not outcomes

The reliability standards applicable in all states except Victoria are actually redundancy standards. They are expressed in an N-X format. 'N' represents the total number of transmission assets in service and 'x' defines the level of redundancy required. For example, if x=1, the transmission system must continue to operate satisfactorily if any one asset is removed from service (for

[9] See AEMO's response to the AEMC's Issues Paper

example, through failure). The most common approach is to use x=1 but in some areas, such as central business district loads, x=2 is often used. Adopted strictly, this is a coarse approach and growth in the peak demand can trigger expensive augmentations which provide only an incremental benefit to customers.

These approaches are adopted in Queensland and New South Wales, and modifications of this approach are adopted in South Australia and Tasmania. In Queensland and NSW, the asset focused nature of the arrangements is exacerbated by assumptions about generator availability where in many cases the biggest generator within a state is assumed to be out of service when undertaking the N-X assessment. This approach also often acts to prevents consideration of alternative inter-regional options to address identified needs.

Deterministic planning limits the national planner from providing a full market based solution to the transmission system.

It requires the transmission system to continue to provide adequate and secure supplies of energy to customers after any of a range of contingencies as no probabilities of contingencies are taken into account. Some assumptions where the largest generating unit within the region is assumed out of service can exaggerate the augmentation required, which thereby drives over-investment of transmission assets and therefore increases consumer costs. This situation does not deliver market based solutions.

While this approach is internationally recognised and applied and has advantages for the regulator in that it is easy to regulate resulting in quick planning solutions, it has a number of shortcomings. These include delivering higher levels of network redundancy above the needs of consumers. These needs do not consider any unique conditions within a region and therefore do not consider intra-regional area loadings or the probabilities of outage. Instead it drives an over-investment in capital projects and increases consumer costs for a substantial period[10].

The effect of a strict interpretation to N-1 can be understood with a review of a RIT-T in NSW by TransGrid and Country Energy[11]. Undertaking a review of the information provided, AEMO has compared the results with what could be achieved under a cost-benefit approach. The N-1 criteria are breached in 2010-11. Using a strict deterministic N-1 approach and the same transmission augmentation option proposed by TransGrid and Country Energy results suggests that the benefits required to justify the augmentation requires consumers to value their electricity at around $9 million/MWh, which is 150 times the value used by AEMO of $60,000/MWh.

In what appears to be an acknowledgment of this value TransGrid and Country Energy have deferred the augmentation beyond the strict application of the standard to 2014-15. This equates to a VCR of around $200,000/MWh. The study also highlighted that if the $60,000/MWh value is used the proposed augmentation would not be cost-beneficial until at least 2018-19, which would represent a substantial cost saving for consumers if similar arrangements were adopted nationwide.

[10] A new requirement of RIT-T applications is to provide information on the expected magnitude and duration of load reductions which occur under the TNSP's reliability planning criteria.

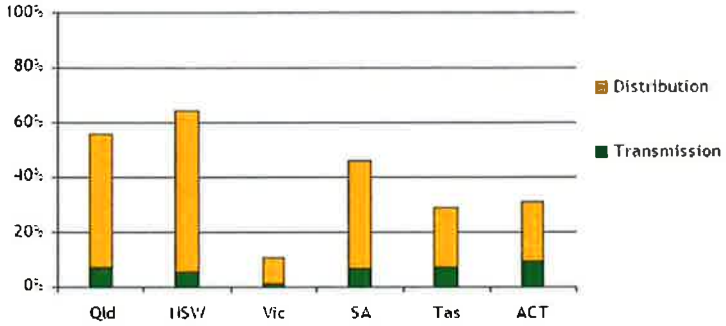
[11] Transgrid, NSW Annual Planning Report, 2011, p. 21

The problems with an input focused standard have recently been recognised by the AEMC's consultants on a review of the Distribution Reliability standards. The Brattle Group has noted in its report,

> Finally, we recommend that reliability regulation should focus on output standards. By imposing input standards, regulators risk becoming overly involved in the utility's distributor planning process. Theoretically, rigid planning standards could be counter-productive because they can prevent distributors implementing innovative approaches to improving reliability.[12]

Figure 5 demonstrates that the lowest transmission and distribution cost increases are in Victoria which are outcomes focused.

Figure 5 - The contribution of network charges to future possible residential electricity price increases (2009-10 to 2012-13)



Source: AER Chapter 6 and 6A Rule Change proposal

The benefits of an outcomes focused approach are demonstrated.

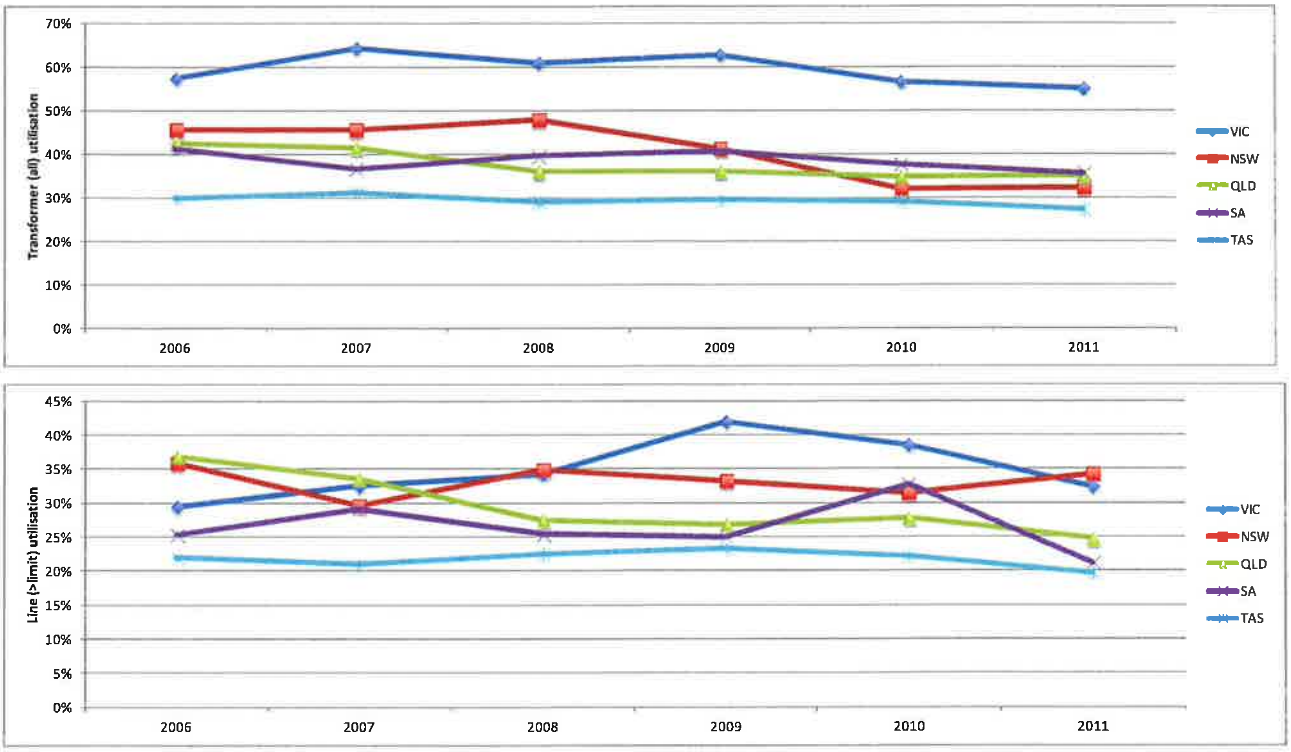
AEMO has calculated existing asset utilisation rates from 2006 to 2011. The data used covers transformers and lines and reflect the average asset utilisation of all circuits in the relevant state.

Various weightings have also been applied to calculate the averages. For transformers, the transformer rated MVA has been used. For lines, the rated MVA has also been used. However, MVA resistance has also been used to attempt to estimate the impact of line length on the averages. For lines the averages for different line voltages have also been calculated to enable comparisons between voltage levels to be assessed.

Figure 6 indicates that Victoria has the greatest utilisation of their networks and efficiency in infrastructure provision over the past five years. This is despite Victoria being one of the 'peakiest' states in the NEM. These figures also demonstrate that any historic over investment in the Victorian network no longer exists.

[12] The Brattle Group, Approaches to setting electric distribution reliability standards and outcomes, p 160, January 2012

Figure 6 –Transformer and transmission line utilisation rates



Source: AEMO

Figure 7 compares augmentation programs with customer density, load density, utilisation, growth in maximum demand with the growth in the regulated asset base, capex and augmentations. Unequivocally, the Victorian arrangements are significantly more efficient on a number of metrics again demonstrating the benefits of an outcomes focused arrangement.

Figure 7 - Comparison of expenditure metric

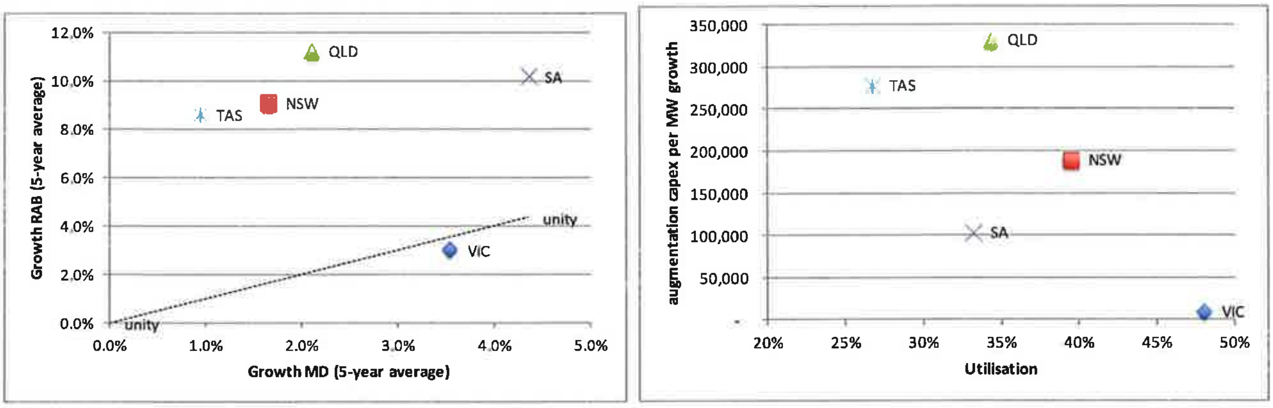
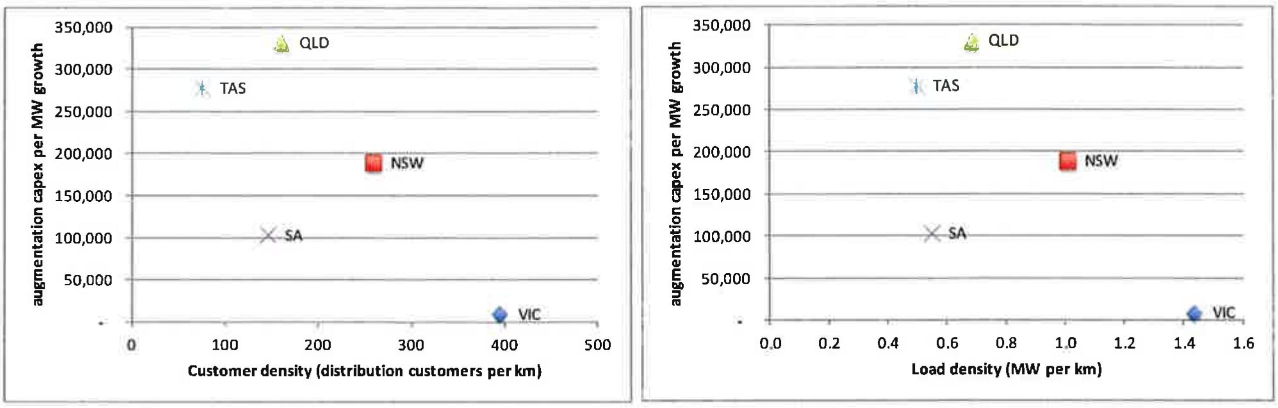


Figure 7 - Comparison of expenditure metric (Contd.)

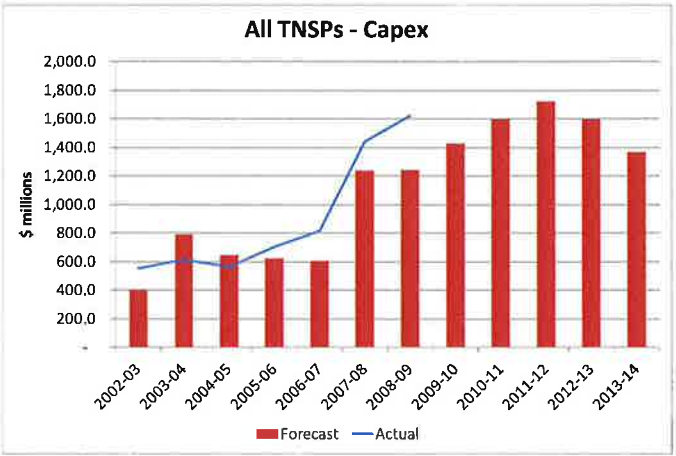


Source: AEMO

2.5.2 The Building Block approach encourages the building of assets

One of the main criticisms of the building block approach is that it closely resembles rate-of-return regulation[13]. While there are incentives designed to improve operational behaviour, the power of the incentive is low compared with the incentive of the business to over-invest in its asset base. This is known as known as gold plating or the Averch-Johnson effect[14]. Figure 8 highlights a significant increase in capital expenditure allowances proposed and approved for the second regulatory period.

Figure 8 – Analysis of Capital Expenditure trends across the NEM



Source: AER

This approach comes at the expense of rewarding TNSPs for increasing network capability via more creative and innovative solutions which do not involve physical network augmentations.

For example, in 2011 the interconnector capability between South Australia and Victoria was increased by 100 MW as a result of studies undertaken by the South Australian Planning Council, ElectraNet and NEMMCO/AEMO. However, ElectraNet have not been rewarded for this improved performance.

[13] See for example Paul Joskow, Incentive Regulation in Theory and Practice: Electricity Distribution and Transmission Networks, 15 September 2005.

[14] Named after the seminal paper on the matter by Harvey Averch and Leland L. Johnson, 'Behaviour of the Firm Under Regulatory Constraints' the paper investigated the effects of the regulatory rate of return being set above the firm's true cost of capital and its decision to invest in capital over labour.

2.6 Acquire transmission services efficiently

The connections regime contains a fundamental limitation to the ordinarily understood concept of "negotiation" because a connection applicant is required to negotiate with a monopoly service provider. A generator has no effective alternative service providers to negotiate its connection within a region.

Monopoly businesses have the incentive and the opportunity to charge above competitive prices. The consequence is that the monopoly will earn profits over and above competitive profits, reducing economic welfare through a net loss of both consumer and producer surpluses. By not offering connections at efficient prices, the regime can also distort or even dissuade some investments.

This could also have an effect on the NEM's ability to meet its reliability requirement. The reliability of the NEM is broadly driven by the Reliability Standard and Reliability Settings[15]. The Reliability Settings includes the market price cap, the cumulative price threshold and the market floor price. For given reliability settings, increasing the cost of connection is likely to lead to a lower level of investment.

The intended safeguards, such as requiring negotiations be conducted on a fair and reasonable basis as a Negotiating Framework approved by the AER and dispute resolution processes do not change this and do not create an environment that facilitates the competitive procurement and provision of connection network services.

This point has been acknowledged by the AEMC in the Review[16] where competition in the provision of network services, even in the provision of extensions, is limited and sometimes might be necessary.

Therefore a framework that supports the competitive provision of these services is required. In Victoria, generators are afforded the opportunity to procure and provide their own shared network services to support their connections or use competitive tendering provisions run by AEMO. The benefit of this approach is that they can discover the efficient connection cost, better manage their own risks and seek the offer which best meets their needs. Large network augmentations can also be delivered competitively.

The framework must support the competitive provision of transmission services where possible to place downward pressure on rising transmission cost.

[15] See the latest review of the Reliability Standard and Reliability Settings, http://www.aemc.gov.au/Market-Reviews/Completed/Review-of-the-Reliability-Standard-and-Settings.html.

[16] Interim First Report, p. 205.

3 A comprehensive solution is required

3.1 Structural change is needed

The challenges identified in Section 2 require a significant change to the Transmission Framework. To deliver customers needs efficiently in this context, the framework needs to

- Signal investment with efficient pricing and congestion management
- Optimise nationally not locally
- Focus on outcomes
- Acquire transmission services efficiently

To achieve these principles will require a combination of structural and regulatory change. One approach is explored in this section.

There are a number of interim steps that can be implemented readily to achieve this outcome. This would include some of the options under consideration by the AEMC to resolve disorderly bidding issues, or in the case of connections to ensure that standardised connection information is provided nationally. However, these matters can be resolved at a later date.

3.2 A new national transmission framework

3.2.1 Signal investment with efficient congestion

At the time of connecting the generator will be able to negotiate an access level with an independent national network planner. This will ensure that generators face their true locational signals of the consequences of their investment decisions.

The access model envisaged would involve specific access rights with some form of payment or compensation from other generators when access is constrained. There are a range of choices to be made in how the scheme is administered and how prices, shadow prices or other financial compensation levels would be set.

Existing levels of access would be grandfathered and then traded between parties, or could be assigned dynamically. New rights could be purchased by generators and traded freely. Such rights could be expressed through the specification and maintenance of standards for transfer capacity across all parts of the grid or specified at certain points in the supply chain.

The rights would be coupled with an incentive regime that would be developed by the AER. This would focus on operational outcomes as measured by the firmness of the rights offered.

3.2.2 Optimise nationally not locally

An independent national planner is required to efficiently plan and develop the national network.

The role of the independent national planner will be to negotiate with and connect new generators and assess the current capability of the network to meet the current and future needs of network users. Any identified deficiencies would be consulted on via a public and transparent process. This information could be supplied via annual national planning documents.

The assessment the independent national planner would offer generators would give the ability to purchase any rights provided by the increased services, after which the independent national planner would determine whether any remaining network would be funded by customers. The decision to proceed would be based on a cost-benefit assessment.

A cost-benefit assessment would consider the needs of individual connection points, as determined by the AER, based on willingness to pay and other targets, and would not be bound by the state boundaries.

The independent national planner would provide national services and be accountable for their delivery and ensuring the transport of electricity from nominated points of supply to nominated points of delivery. Defined via negotiations with the AER service standards would be applied at load centres and at connection points and services. The independent national planner would procure network services from network service owners.

The independent national planner will be responsible for coordinating outages and setting network ratings.

3.2.3 Focus on outcomes

Revenue regulation would focus on rewarding and penalising the efficient utilisation and replacement of existing assets. The utilisation would be linked to the reliability levels with rewards for the provision of services. Such rewards could be achieved by allocating a portion of the value of energy at connection points and rewarding the business for maintaining capability and meeting defined reliability level. Levels would be reviewed on a periodic basis and revenues would be adjusted accordingly.

3.2.4 Deliver transmission services with competition

The market is capable of delivering efficient solutions in three areas; the development of new transmission services to facilitate a generator's connection; the provision of tradeable rights, and, delivering elements of the transmission network development supply chain, specifically in its construction, operation, ownership and maintenance.

At the time of connection generators will be provided with the choice to procure and provide all network services associated with their connection, be they shared or connection, or to enable the NNSP to provide those services. The generator would also have the ability to procure and provide deeper network services that enable it to achieve its desired access levels.

To address the information asymmetry issues that presently exist there will be greater transparency before and during the connection process. This would involve standardised contracts, clear information on the roles and responsibilities of various parties.

At the time of the connection the NNSP would consider the location of the connection and consider the future requirements and scale any network investments appropriately. These costs would be borne by the Generator with future cost sharing arrangements to be specified in transparent rules or guidelines and defined around service levels, not assets.

4 The AEMC's First Interim Report

4.1 Access

The AEMC's First Interim Report has listed five access option and requests comments on each of its options. AEMO's comments are provided to each in turn.

4.1.1 Option 1 - "Open" Access without Congestion Pricing

AEMO does not support the status quo. There is an inefficiency created by the poor management of constraints and utilization of the current transmission system, the limited linkages between connection of new generators and the grid's development and the inefficient locational signals for new generation. The inadequacies of the current model will become more evident in the future as the market faces the forecast investment challenges.

Rule 5.4A has not been used to successfully negotiate levels of access in the NEM. While it has not been successfully used to date and is difficult to implement in the existing shared network given the bi-lateral connection negotiations, AEMO considers that it should not be deleted until new arrangements are implemented. The "open access" label for options 1 and 2 implies access level uncertainty is a feature of open access regimes.

Regulators in the EU considered the term "open access" came to the conclusion that there is no general definition for the term. They state that

> "Generally, it is understood as referring to a form of wholesale access whereby operators are offered transparent and non-discriminatory wholesale access, thereby enhancing competition at the retail level."[17]

The term does not mean either free or unfettered access on the one hand nor does it require that the level or nature of the access provided is uncertain.

Other networks, such as telecommunications and regulated contract-carriage gas pipelines, where the network owner and user have defined and agreed upon terms and payment for a defined level of network access are still defined as open access. These arrangements are somewhat analogously to option 4.

Conclusion

AEMO does not support the status quo given the deficiencies of the current arrangements and the forecast investment challenges.

4.1.2 Option 2 - "Open" Access with Congestion Pricing: SACP

AEMO and the AER, amongst others, have raised significant concerns about the prevalence of inefficient dispatch provoked by the incentive to bid away from costs caused by the regional settlement arrangement in the presence of any congestion that is not perfectly aligned to a regional boundary. The report has captured these concerns but understated them as an incentive to bid at the market floor price with dispatch pro-rated[18]. The most serious events have been provoked by the use of "hard" technical constraints on generation output, such as artificially reduced rates of

[17] See Report on "Open Access" by the Body of European for electronic communications at http://www.irg.eu/streaming/BoR%20(11)%2005%20BEREC%20report%20on%20Open%20Access_final.pdf?contentId=547137&field=ATTACHED_FILE

[18] First Interim Report, p. 33

change. Rather than a "pro-rata" sharing of network capacity, these behaviours can lead to a "winner take all" outcomes. Strategic bidding of these parameters on units with small coefficients in binding constraint equations has on occasion constrained efficient competitors by as much as a factor of four.

Most importantly, these known flaws in the market design lead to a number of occasions when the competitive market design fails to drive participants to disclose their true costs. Since all dispatch and pricing is based on participants' bids and offers, this is a serious weakness which can flow through to inefficient outcomes in the spot market. Spot market prices are the basis of futures market contracts and a reference point for bilateral contracting. While the gross distortion of dispatch and pricing may not be an economic loss, losses undoubtedly accrue.

The intent of this package represents a positive first step. It will remove the incentives to distorted bidding and should therefore resolve much of the inefficiencies caused including those to dispatch, pricing and network utilisation during congestion. While the system requires modification to the settlement systems only, this package would have a relatively low implementation cost. The major change would be through the changed incentives and hence the bids and offers of participants.

While we support the intent and agree that option 2 would be step in the right direction, AEMO does not consider that it does not represent the type of holistic solution we consider is needed. For example, Option 2 does not:

- provide long-term access certainty to generators, supporting certainty to investors
- alter the role of network providers or the incentives on them in the market.

Some of these matters are further outlined in the following. Some particular features of the package as proposed need further assessment and these issues are also raised.

SACP Mechanism

AEMO concurs with the Report's Appendix B of the First Interim Report, that a time-limited, localised congestion management mechanism is difficult to implement and unlikely to be effective. The SACP mechanism with a generalised automatic application upon binding network constraints has emerged as the most promising congestion management scheme in the absence of more fundamental change. It should now be subject to a proof-of-concept assessment.

AEMO understands and agrees with the majority of the SACP description in Appendix A of the First Interim Report, subject to the following comments:

- The report states "Some changes would be required to AEMO's dispatch and settlement processes and systems would be required"[19]. Our understanding of the proposal is that no changes would be required to dispatch processes. An automatic settlement adjustment will be required for those power stations and interconnector settlement residue with dispatchable terms in binding constraint equations. These adjustments would be triggered and calculated from existing dispatch outputs.
- The report has varied from the "Southern Generators" proposal in one important detail: the derivation of an availability value for interconnectors. The report has proposed a nominal static value, rather than the next most binding constraint. That had been suggested as best representing the real-time capacity of an interconnector. Selecting a fixed, nominal

[19] Ibid. p. 72

capacity could enhance inter-regional trading, but may be seen as inequitable upon downstream generators. It also requires the selection of a nominal interconnector capacity, which would be arbitrary and potentially controversial. This design variation needs further consideration and discussion.

- The worked examples in Appendix A are useful for explanation but are all radial constraints with unity coefficients. Experience shows many serious congestion events with looped constraints. AEMO understands the SACP is intended to be equally effective in these cases, and encourages the AEMC to articulate these also.

Economic outcomes

The attraction of the SACP is that it divorces the allocation of network capacity from physical dispatch outcomes, thereby removing the incentive to distort that outcome through disorderly bidding, whilst still allocating that network capacity to generators, by pro-rata sharing. This has an appearance of equity, and, by allocating proportionally to the generators' constraint coefficients, allocates roughly according to generator "need". For example, if all generators in the constraint equation had similar hedging policies, then this pro-rata network rationing is similar to what would be expected from an efficient network capacity auction.

Of course, allocating network capacity pro-rata may not be the same as that which would arise from a negotiated access framework. This is not possible without a more substantive reform. However the SACP allocation is superior to the status quo, which allocates capacity to the most disorderly bidder.

Importantly, it restores some network access to interconnectors: which are seriously disadvantaged by the status-quo as they are incapable of disorderly bidding. This should restore confidence in the settlement residue instrument and encourage inter-regional trade and competition.

The report states:

> [in general]...no generator is worse off than it would have been if it had engaged in disorderly bidding under current arrangements.[20]

This holds in a simplified situation of floor-price disorderly bidding and radial constraints without interconnector terms. As shown by AEMO's earlier submissions, disorderly bidding tends to result in "winner-take-all" outcomes, and some generators, particularly those competing with interconnectors, are well placed to take a greater share of network capacity than pro-rata[21]. AEMO also showed that the inability to fully exploit network capacity during disorderly bidding can result in higher spot prices.

[20] First Interim Report, p. 73

[21] See AEMO's submission to the AEMC's Issues Paper

Generator availability bids

The SACP allocates congestion revenue according to presented availability. The Rules oblige generators to present their true capacity, and occasional inaccuracies have been sanctioned[22]. As the SACP would encourage over-stating this quantity, a greater regulatory over-sight of availability bids would be required.

However, SACP will at the same time remove incentives to incorrectly state other technical parameters, such as "fixed" status, rates of change and the frequency control ancillary services trapezium. In comparison to these quantities, availability is a more transparent and definable value.

Co-optimising Generation and Transmission decisions

Through its congestion information resource, AEMO produces a considerable volume of data on congestion. An economic value of congestion remains difficult due to the presence of disorderly bidding which exaggerates the marginal value of constraints. The First Interim Report therefore correctly states that the introduction of a congestion scheme should provide additional information on the cost of congestion[23].

The existing Service Target Performance Incentive Scheme (STPIS) has been designed to avoid distortions created by disorderly bidding. It accumulates a penalty value for every dispatch interval that an outage constraint marginal value exceeds ten dollars, rather than attempting to accumulate the economic cost of those constraints which may be skewed by disorderly bidding.

After the implementation of SACP, the STPIS could be left unchanged and would continue to function as effectively. However if SACP proves to effectively resolve disorderly bidding, it may be possible to improve on the STPIS and more accurately recognise the severity of constraints. This should be considered as an optional future benefit rather than a mandatory implementation cost[24].

Conclusion

Option 2 could be expected to provide a significant improvement to the market and represents a positive first step. This package could be considered for early implementation in transition to more substantive reform or as an adjunct to other reforms.

4.1.3 Option 3 - Generator Reliability Standards

In its consideration of Generator Reliability Standards the AEMC has noted the following

> We do note that the combination of deterministic planning by for-profit, and often government-owned TNSPs has apparently led to a greater level of satisfaction with planning arrangements amongst large generators in NSW and Queensland, compared to generators in Victoria.[25]

AEMO's review of submissions could not identify such a geographic distinction. For example, AGL has a larger generation presence in South Australia than Victoria, along with a large presence in Queensland, and recommends investigation into new access arrangements. On the other hand,

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[22] See for example: http://www.aer.gov.au/content/index.phtml/itemId/656299

[23] First Interim Report, p. 74

[24] See Grid Australia presentation pg 12 http://www.aemc.gov.au/Media/docs/1.3%20Peter%20McIntyre%20-%20Grid%20Australia%20-%209%20Dec%20215pm-511ca608-2f4c-4e12-8f2e-9b8a7cb58b52-0.pdf

[25] First Interim Report, p.38.

Snowy Hydro owns approximately 2,100MW of generation in the Victorian region, but has recommended no change.

If a generalisation is required, ownership seems more significant than geography. This is not surprising, as there is no evidence that generator congestion risk within Victoria is more severe than in regions which use deterministic planning.

If there were such evidence, there is no obvious reason it would be the result of the planning arrangement. The AEMC seems to accept a claim that a deterministic standard for load obliges the TNSP to over-build network capacity such that upstream congestion is inadvertently removed. This does not follow as the removal of risk for customers requires reinforcing the load-rich parts of the network, rather than the generation pockets where congestion arises. For example, the causes of the Latrobe Valley transformation outage constraints cited by TRUenergy in its September 2010 submission are unrelated to the Victorian planning approach.

In any event, it appears unlikely that any scheme which tends to overbuild would meet the NEO nor act to mitigate the fast growth in network costs.

Conceptual basis of generator reliability standard

The paper's discussion appears to accept a premise that a deterministic planning approach is more transparent, simpler and results in greater network build than probabilistic planning. AEMO submits that the point about transparency is not the case. Deterministic N-X planning, as applied in Australia is not transparent with key network condition assumptions such as the patterns of generation, difficult to ascertain. Further, the apparent simplicity of deterministic planning is an artifice of its opacity. Network conditions are inherently complex and never consistent between planning scenarios, so the deterministic planner must make an intricate judgement of the most appropriate conditions to present in a single network condition to its N-x test. The stakeholder will sees only that selected single condition, rather than the infinite range of other conditions that the planner chose to discard.

Where the deterministic standard x is derived from an economic criteria, and this is done in an unbiased manner without "rounding up", then it should, on average, lead to an equal network build than probabilistic planning. A full probabilistic approach would, however, by its nature allow the standard to adapt to any changes in the situation or the available solutions rather than be fixed to those considered at the time the assessment was made.

The First Interim Report does not propose that a conservative "rounding up" approach, would be used for generation when economically determining zonal standards. This implies that the generation sector should not expect a higher level of build, on average, than would occur with probabilistic standards: instead some network apparatus will be built a little earlier than the optimum time, and others a little later.

Although the planning processes would change, the outcomes of the deterministic standard would nevertheless appear to converge to a similar total network build as the status quo.

Linkage to generator charging schemes

The proposal to introduce zonal G-TUoS charging has significant efficiency and wealth transfer implications. These were discussed in detail in the AEMC's 2009 Energy Markets Frameworks review.

The combination of G-TUoS and generator reliability standards has the attraction that the introduction of a charge is offset by some sort of a benefit. However there is no clear conceptual linkage between G-TUoS and a generator reliability standard: neither mandates the choice of the other. AEMO agrees that a contribution to locational TUoS can have locational efficiency advantages for new generator siting, however AEMO suggests that if it is progressed, it should be introduced with a reward in the form of a firmer level of access certainty. With only a vague promise to a standard, generators seeking to invest do not have a sufficient certainty at the time of investment to be able to project their costs and dispatch especially during the critical first years of the project.

Implementing a generator access "reliability" standard

A "standard" is a consistency of service, implying that the benefits of consistency outweigh the cost savings of tailored solutions. This can have a logical basis when considering service to groups of customers due to the averaging effects of aggregation[26]. When attempting to formulate a standard for generator access, Hill Michael's report quickly uncovered the real challenges of implementing a "standard" level of access to the very non-standard world of generation"[27].

AEMO concurs with Hill Michael's discussion and their conclusion that a generation reliability standard would require a complex selection of conditions and market based simulations to determine whether the forecast levels of congestion breached a multi-dimensional standard. Also that quite a high level of granularity in the standard would be required.

We also agree with Hill Michael that whilst the proposals received from generators have indicated their desired outcome, they have not engaged with how those standards could be implemented by a network planner[28].

It appears these simulations discussed by Hill Michael would have many similar characteristics of probabilistic planning, and that the necessary complexity of the standard setting and its application undermine its claimed benefits of simplicity and transparency.

The large practical challenges of implementing a "standard" in generator access, as recognised by Hill Michael, have not been adequately recognised in section 8 of the First Interim Report.

Assigning rights and congestion management

The Report proposes to apply the standard to transmission planning only, and to not approach questions of congestion management and access priority.

If the intent of the access standard is to provide a more predictable level of access for generators who value it highly, then this cannot be achieved purely through network planning. Rationing of the network, once built, must also be contemplated.

Improving the probabilistic approach

Much of the criticism levelled at the probabilistic approach relate to its implementation rather than its conceptual basis. The probabilistic approach is already benefiting from, and can benefit more, from the use of standard inputs to RIT-T calculations.

[26] Notwithstanding AEMO's reviews of the average Values of Customer Reliability do show significant geographical variations.

[27] Hill Michael, Development of Transmission Reliability Standards for Generators, Report to AEMC, 2011, p. 15

[28] Ibid, p. 28

The paper discusses the benefit of access certainty to generators: congestion that is economically efficient in an SRMC model creates transaction costs in the hedging market, leading to higher market risks and inflated risk premiums. This may well be true, and network planners may not yet be taking it into account, but its consideration is not disallowed by the probabilistic approach implied by the RIT-T.

Determining this economic value of access certainty will necessarily be difficult and judgement. But the access standard approach still requires it to be performed:

> The economic analysis underlying the reliability standards would assign a specific economic value to access certainty, which is not currently factored into the RIT-T.[29]

If it is possible to perform this analysis for the purpose of the access standard, then there is no reason for it to be excluded from the RIT-T. If an estimate of this value, say to different fuel types, were estimated through a robust, focussed modelling task, then it could be used by network planners in all future economic RIT-T assessments. This is similar to the way planners widely use AEMO's Value of Customer Reliability as an accepted input source to probabilistic planning.

Conclusion

Option 3 as with Option 2 puts forward a partial solution to the deficiencies. It loses the benefits of Option 2 as it does not change the incentives participants face in the market when bidding. The proposal to introduce a generator TUoS regime could in principle provide an improvement in the locational signals to generators seeking to connect but faces a challenge to develop an efficient pricing regime. Critically the warranties of access "standards" provided generators would be difficult to define, potentially inefficient in their own right and they do not provide adequate certainty to new investment. AEMO therefore suggests this package should not be further considered.

4.1.4 Option 4 - Regional optional firm access model

AEMO supports further investigation into the provision of a level of generator access stability, which also links into decisions about developing the network. AEMO agrees that the potential benefits of this option include certainty of access, locational efficiency and shared decision making about network investment between generators and planners.

Dispatch, congestion and compensation

The process of compensation as discussed in the Report[30] for recognising access rights within the dispatch process concurs with our understanding of how a self-funding mechanism could work without altering the dispatch process itself and its objective of seeking to maximise the value of trade. Having AEMO's market operation function settle the compensation adjustments, rather than the relevant NSP as proposed in Rule 5.4A, seems appropriate.

Incentive for firm generator to bid below cost

The Report has discussed the incentives for generators with/without rights to bid reflective of costs at specific nodes and has concluded that disorderly bidding incentive should disappear. AEMO agrees the incentive is mostly removed, but that there remains an incentive for a firm generator bidding below its own costs, to an increment above a neighbouring non-firm generator's bid, in

[29] First Interim Report, p. 87

[30] First interim report p. 96

order to maximise compensation payments. The report however concludes the risk of the generator miscalculating a gamed bid should overcome the incentive[31].

AEMO notes the NEM design effectively allows generators to adjust and re-adjust bid prices every 5 minutes, and therefore expects the incentive to remain significant. For that reason these schemes usually limit compensation payments to that determined by a generally accepted list of short-run marginal costs for that type of generator.

Disorderly bidding of non-firm generators

Much of AEMO's support for options 2 and 4 is due to their resolution of disorderly bidding, which presents a clear and material detriment to efficiency in the status quo. For constraints where all capacity has been allocated via rights, the compensation technique of package four will remove the disorderly bidding incentive: marginal increases in output receive only the nodal price. This is recognised in the paper.

However in constraints where there is significant uncontracted capacity, the incentive may remain. It will be necessary to retain a SACP mechanism for the uncontracted capacity, to ensure that disorderly bidding does not occur between competing non-firm generators.

Short-payments

AEMO concurs with the report's recognition that, being self-funding, there will be a risk of short-payment when network capacity is limited. AEMO suggests that this short-payment can be a useful measure of the performance of network planning and operation. It indicates where the network has failed to deliver the access allocations, for example due to poor planning or a badly-timed outage. Exposing the asset owner to the full liability of the short-payment would introduce unnecessary risk however it could be used for a market performance incentive with penalty payments made to the generator.

Charging non-firm generators to cover the short payment as raised in the report does not seem appropriate as they have no control over its cause.

An independent planner with greater operational control, such as setting network ratings and co-ordinating outages, could also oversee the administration of this short-payment and-where necessary allocating it to the asset owner responsible.

Interconnectors

The report has not discussed the assigning of rights to, or the compensation treatment of, interconnectors which directly compete with in-region generation during congestion. It is important that the needs of inter-regional traders, through their dependence upon Settlement Residue Instruments, are recognised with generators when competing for network access.

Inter-regional traders contribute to the cost of the network, by purchasing these rights at auction. The ability to restore much needed firmness to the settlement residue instrument is a key benefit of implementing either option 2 or 4, resulting in:

- Lower risks for hedging when using the settlement residue instrument.
- Restoring the ability to hedge inter-regionally to a total volume approaching the installed capacity of the interconnectors.

[31] Ibid. p. 97

- Introducing national competition into the NEM's hedge markets and removing the significant inter-regional divergences of forward prices.
- Increased buying interest in the settlement residue auction, thereby obtaining higher prices and offsetting network costs to consumers.

Initial assignment of rights

The implementation of option 4 will inevitably introduce debate, on transitional arrangements, such as grandfathering existing capability or auctioning the rights. This has major wealth transfer implications. In the long run actual method chosen is irrelevant to the overall efficiency of the scheme.

The Report suggests that a starting point based on a one-off release of rights has an efficiency detriment in that there is no mechanism or incentive for generators to become non-firm[32]. AEMO suggests that where an incumbent generator has been assigned a right that becomes of more value to another, then there is a market incentive for a transfer to occur between them. The transfer mechanism can be explicit, for example if the right is of a readily transferable form, or implicit, where the two generators agree on a "back to back" contract to exchange the benefit of the right.

A starting point based on grandfathering may appear generous to incumbents. However the implications on various parties of such a grant against the status quo:

- For incumbent non-intermittent generators, it is clearly advantageous as their existing implicit right will be recognised and stabilised at no cost to them.
- New-entrant generators will be able to quantify exactly what would be the cost of achieving firm access at varying nodes before they invest, and then be assured that that would not decline over the life of the project.
- All intermittent generators will be able to increase annual energy output, as they would no longer be constrained off by the disorderly bidding of higher cost plant.
- Incumbent intermittent generators will be granted a level of access presumably in excess of their requirements, and will be able to transfer this at some profit to non-intermittent generators who need it more for their hedging.
- Customers will also be better off as:
    - The locational incentive upon new entrants would lead to a more efficiently built network.
    - The reduced hedging risk on generators and inter-regional traders would increase competition and deliver lower overall costs.
    - Future purchases of rights by new-entrants would offset customer network tariffs.

Option 4, even when combined with a free one-off allocation of rights to incumbents, will still represent a Pareto gain compared to status quo.

G-TUoS and Deep Connection Charging

AEMO recognises that this issue is that needs to be solved. In either G-TUoS or Deep Connection Charging, options vary between grandfathering, funding holidays or immediate equality.

[32] First Interim Report, pg 95

AEMO notes considerable incumbent participant concern about G-TUoS, although this might be moderated through a partial or full grandfathering approach. G-TUoS implies less accuracy in the estimation of the true cost of providing firm access, as opposed to deep connection charging. Where this is material, it would result in a less efficient locational signal.

AEMO does not share the Report's concern that special arrangements to allow generators to switch between firm and non firm status is required, because as discussed above, these rights would be explicitly or implicitly transferable. Further, variability in the volume of firm rights on foot would complicate the network planning arrangements and might create gaming opportunities.

The Reports has rejected deep connection charges on the basis of three matters[33]. Taking these in turn:

- Discrimination between incumbents and new-entrants. Contrary to the Report's conclusion, AEMO does not see why the reallocation of sunk network costs to sunk generators are necessary for efficient network usage. It is potentially relevant in the case where incumbent generators no longer require a high level of access, for example where they are considering exiting the market. As discussed above, it would be expected that such generators would happily sell their excess access rights to new entrants if they remain of value.
- The lumpiness of transmission assets resulting in non scale-efficient decisions. This issue was thoroughly considered in the Scale Efficient Network Extensions rule change. The AEMC concluded in that case that the risk of burdening customers with network assets that do not prove necessary was too great, and left the burden of arranging scale efficiency to generators. The Report however concludes the reverse, that generators should not face the full incremental cost of their decisions. It sees a benefit of G-TUoS that the TNSP will recover the cost of scale efficient assets from generators over time, implying the AEMC is now supporting the risk of under-utilisation to be borne by customers.
- The complexity of accurately charging deep connection charges. If the charge is only applicable to new assets and then the calculation should not be complex. The cost of the specific new assets needed to be built to deliver the firm access for the new entrant is the only ones that would be included in the charge. It could be argued that deep connection is actually simpler, because there is only one discrete augmentation that must be considered. Moving to an averaging technique such as G-TUOS does not simplify the calculation. It smears inaccuracies. And the following statement is incorrect, because within an access rights regime, bidding behaviour is no longer relevant:

  > Establishing a charge....requires a number of assumptions, such as....predicting network flows that are dependent on generator bidding behaviour[34].

Generator access planning standards

AEMO agrees that changes to network planning approach are required so that firm access rights can be recognised in the planning environment. We do not agree with the Report's proposal that these would be via a standard that

> would be similar, in principle, to the proposed generator reliability standard that is discussed in some detail in the previous chapter[35] (i.e. package three)

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[33] First Interim report, p. 98 & 99

[34] Ibid, pg 99

AEMO agrees that

> The firm access planning standard would require that, under defined transmission operating conditions and assuming away all non-firm generation, all firm generators would be able to access the RRN.[36]

This implies that the network planner is required to analyse the network nodally, ensuring the evacuation of all firm capacity. It would be approached differently, and lead to quite a different outcome, than that proposed in Option 3. For example, unlike package three, the planner will use a different evacuation obligation depending upon which generators at that node are firm versus non-firm.

Such planning would in fact be simpler than Option 3, as the planner would not need to make predictions of actual dispatch patterns, nor the economic values of certainty to individual or future generators. It would also be more transparent.

Conclusion

Option 4 presents a general framework with the most promise to provide both short term operational efficiency gains and long-term access certainty. AEMO therefor supports its further development. With respect to design decisions already presented in the Report, AEMO agrees generally with the approach but disagrees it is necessary to apply the generator reliability standards of Option 3 to network investment.

On the matter of allocation, equal treatment of existing and new generation, and existing and sunk networks, is not necessary for achievement of efficiency within the package.

4.1.5 Option 5 - National Locational Marginal Pricing (LMP)

Option 5 represents the most substantial change and if progressed, would have a long period of detailed development. The introduction of full national locational marginal pricing would raise a number of technical complexities which would need analysis and decision to confirm a feasible design. The discussion below is therefore limited to high level themes only.

Benefit Characterisation

The high level benefits of the option and how they compare to other options include:

- Efficient dispatch of generation
- A greater level of generator access certainty access rights that are firm to network failure
- Locational efficiency, through the charging of new-entrant generators the cost of access

Idealised national competition as regions are removed and firm financial transmission rights are introduced. This would remove the current (very) non-firm inter-regional settlement residues and the inability of generators to manage their intra-regional congestion risk. Instead, option 5 would enable generators and retailers to permanently "assume away" all congestion: once they have bought their access rights they are guaranteed permanent access to customers anywhere in the NEM, greatly simplifying their trading.

[35] Ibid, pg 100

[36] Ibid, Pg 100

The potential benefits make the package worthy of investigation. However the scale of change which is required to implement this package makes it worth considering the benefits it would offer over option 2 and 4. In that respect we note that:

- Changed bidding behaviour and more efficient dispatch is also delivered in part by option 2 and in full by optoin 4;
- The changed bidding behaviour would improve the firmness of inter-regional settlement residues although still leave them non-firm to network failure or physical restriction;
- The greater level of access certainty is welcome but could also be achieved in a large part in Option 4; and
- Efficient locational signals for the connection of new generation are also necessary but could be achieved in package four.

The proposal to have firm transmission rights is commendable. However it is unclear whether this is realistically achievable technically and within the NEM industry structure and regulatory framework.

Pricing of load

The model has drawn heavily from the UK approach of a single System Marginal Price (SMP) to apply to all load, which simplifies the competitive retailing process. However the Report has overlooked the very large efficiency sacrifice that this would imply in a network to the NEM's geographical extent. The weather conditions in the major NEM load centres, and therefore the timing of peak demands, are uncorrelated[37].

The mispricing of load would have perverse outcomes, for example, the single SMP would raise customer prices in Hobart when Brisbane has a hot day. Tasmanian load prices could remain low even where local water storages were in serious jeopardy. The single SMP would remove all incentives for the demand-side to participate in achieving supply/demand balance[38], and in that regard seems inconsistent with government policy and the objectives of the AEMC Power of Choice Review.

The US LMP markets employ nodal pricing for load. That may not be necessary, but it would seem preferable to maintain at least the current regional structure for load pricing. This would require five SMP hubs, and a continuation of the concept of "interconnectors" between those hubs, at least for the purposes of rights and access allocations.

Network Institutional structure

AEMO fully agrees that a single national decision maker in transmission planner and operator would greatly assist the benefits of the Option. However it does not follow that this is incompatible with independent national transmission planner.

An independent national transmission planner could be a pragmatic way to implement the option. Existing asset owners would not need to merge. Instead they could become service asset owners to the national planner.

[37] Except for Adelaide and Melbourne, where there is a strong correlation of peak demand conditions.

[38] Except in the rare case where the full extent of the NEM is in simultaneous supply shortfall, an unprecedented circumstance.

A strong incentive to maximise available network capacity is a key benefit of the scheme. This is also still compatible with the independent planner model. AEMO has transmission incentive arrangements in place with Victorian asset owners. A national independent planner could allocate and pass on these incentives to multiple network asset owners. The advantage increases further where the independent national planner has a significant role in operations such as setting network ratings and co-ordinating outages.

Conclusion

AEMO considers that Option 5 requires the most radical reform of all packages. Some aspects of the package would provide real benefits to the market and market efficiency but most of these can be delivered with a well developed variant of option 4. Some other facets such as firm rights and a single SMP would have serious impacts on market efficiency.

4.2 Connections

The First Interim report has identified three options to improve the provisions for connections to the grid. These options are put forward by the AEMC as potentially applicable to any of the five broader options discussed above. The options, and AEMOs comments, focus on the 'shallow connection' matters.

The discussion also focuses on the connection of generators which face particular issues during a period of high investment and major change in the generation portfolio. However there are issues in the connection of customer loads and distribution connections which also warrant attention. Some of these issues are being addressed in the AEMC's review of the distribution planning framework.

The proposed options are addressed in turn in the following.

4.2.1 Enhancements to dispute resolution provisions

Overview of the NEM's connection process

The NEM's connection regime is designed around a bilateral negotiation between a monopoly TNSP and a generator that centre on the TNSP's obligation to provide a connection offer that is 'fair and reasonable' and approved negotiating frameworks.

The negotiation of a connection includes the process to negotiate the technical standards that will apply to the connecting generator. The Rules establish the limits of the negotiating range; the minimum standards that connection applicants must meet and the automatic access standards that guarantee connection. The parties then negotiate the actual standards that will apply, the negotiated access standards, between these bounds. The cost of achieving a particular performance can be high, high enough to destroy the viability of the project. The technical analysis can be burdensome and the negotiation of some key components is made more difficult because of a lack of clear criteria.

In addition to the technical standards applicable, a wide range of other matters need to be negotiated. Most importantly these include a range of commercial terms relating to the construction and performance of connection assets, payment schedule, overall price and risk allocation. Those terms and conditions have no guidelines, or in some states, protections under the Rules.

Where a connecting party considers that they are not being made a fair and reasonable offer, dispute resolution provisions apply. The dispute resolution provisions are designed to mitigate against the relatively strong negotiating position of the TNSP. Despite the safeguards, connection applicants face a considerable information asymmetry and vexed position as they seek to negotiate a range of matters which are often critical to the project's financial viability and time critical to resolve.

AEMC's proposed change

The First Interim Report proposes the option of strengthening the dispute resolution process as a response to imbalance in negotiating positions of connection applicant and TNSP. The suggestion is to have a more easily accessible dispute resolution process that can easily resolve connection issues and build up a bank of precedent decisions in the process. We agree that an effective Dispute Resolution process is a necessary safeguard to the countervailing negotiating power possessed by monopoly businesses. However, the current provisions, which have not been fully tested, have not resolved the primary issues raised by connecting generators, namely the competitive provision of services to support their connections.

Why enhancements will not improve the process

AEMO does not believe that the enhanced dispute resolution proposal will address the connection negotiation problems for a number of reasons

Most importantly, it will not improve the competitive provision of transmission services. This is discussed further in section 4.2.1.

The dispute resolution process is seen as time consuming in a process where often time is of the essence. Where external financing is needed to build the generation plant, the connection agreement is a pre-condition to obtaining the finance and works cannot commence until the connection is sorted. To delay a connection negotiation to address commercial issues in a dispute resolution process risks delaying the project and potentially making it unviable.

The AEMC has suggested establishing an independent arbitrator (such as the AER) to decide on stalled negotiations. There are time saving benefits to publishing the decisions of the arbitrator and in the long term, development of a precedent database might lessen time delays by giving generators and TNSPs guidance in particular situations. It can also bring its own difficulties such as inflexibility and managing confidentiality. But in the short to medium term, taking a disputed negotiation to an independent arbitrator seems to add to the time needed to complete a negotiation.

Where decisions are made by an arbitrator for any given fact, making that decision binding on all subsequent similar fact situations necessarily introduces inflexibility. In other words, where a precedent exists, other ways of achieving the same outcome can be either prohibited or discouraged as TNSPs will be tend to limit their offerings to packages that they know will pass the dispute resolution test. The trade-off between inflexibility against certainty in is something that the AEMC will need to satisfy itself. However AEMO believes that the potential stifling of innovation over time will be costly as efficiency gains from the innovation remain unrealised.

The NEM framework for the negotiation of technical standards is unique and seeks to acknowledge that different connection points and generation technologies raise different issues and offer different potential solutions. Providing a negotiating framework is not as simple as more prescriptive standards regimes that often apply in other markets, but aims to allow flexibility to deliver appropriate standards and efficient connection.

Dispute resolution proceedings require the disclosure of confidential or commercially sensitive information. Even the fact that a party is seeking to connect at a particular location may be seen by that proponent as confidential on some occasions. Disclosing confidential and/or sensitive information acts as a disincentive to relying on such proceedings. Allowing this sort of evidence to be given in confidence may remove some of the hesitation to provide it but failure to make this information public undermines public confidence in the process because the basis on which decisions are made is unknown.

Dispute resolution processes also take up a lot of resources and divert expertise into less productive endeavours. They can cause the breakdown of what otherwise needs to be a constructive relationship between the two parties and always carries the risk of abuse. Parties to a negotiation can use it or threaten to use it as a tactic to delay the negotiation process.

4.2.2 Enhancements to the negotiation framework

AEMC's proposed change

AEMO supports enhancements to the negotiating framework. This balances the desire for a freely negotiated connections process while tackling the obstacles to efficient pricing and service delivery caused by asymmetries of information. In our view, requiring greater transparency to potential pricing and other contract terms within the negotiation process provides the best and most effective way of delivering timely connections at an efficient cost.

However, the AEMC's suggested approach does not go far enough. It needs to be combined with a commitment to an expanded competitive provision of connection related services. The benefits of competitive provisions are explored further below. The original National Electricity Code and the Rules have always made provision for some assets to be classified appropriately and contestability allowed for their supply. These have had limited success in most jurisdictions. In Victoria such measures have applied. Recent work undertaken through AEMO's Connections Initiatives workstream has reaffirmed our commitment to increase the level of competition in the provision of transmission services.

Benefits of competitive provision

There are many economic benefits from the competitive provision of transmission services. Despite the difficulties identified in the First Interim Report the benefits outweigh the costs. Of the two recent Victorian connections, one was provided via an AEMO run competitive tender process, with the other constructed by the generator.

All occurred within the existing network with coordination between third parties and the existing asset owner.

Comparisons between tenders over the years is difficult and requires consideration of the project under construction, whether it is on a greenfield site or an upgrade to an existing terminal station, whether there are land or easement acquisition issues, and how technically complex it is to connect it to the existing transmission network.

However, it appears that the benefits of competitive tendering increase proportionally to the size of the project. For example the difference between the tender prices of the winning tender and the highest tender for series capacitors was $[][39] million, in NPV terms, while in 2005 the difference between the winning tender and highest tender for two new transformers was $[][40]million in NPV terms.

The evidence from Victoria also shows that contestability can apply equally within and outside the network. There is no justification for demarcation of contestability on the basis of the existing network boundary. There is no reason why an asset owner cannot accept the risk associated with allowing a third party access to its sites or accept transfer of assets constructed by third parties. There may be a different risk profile associated with allowing connection assets to be built by a third party. But that can be effectively dealt with by a combination of clear and measured function specification prerequisites, conditions of entry to site, insurance requirements and risk allocation under contract. Most new transmission construction in the NEM is actually undertaken by third

[39] Confidential data has been removed

[40] Confidential data has been removed

parties in any event. In many cases, the same contractors and suppliers could be involved in the generation project and the transmission connection.

Despite that, some works will always need to be reserved for the existing network operator to perform. For example of certain essential electrification works such as cutting into the existing transmission lines and associated interface works.

Alternative Competitive Models

The most difficult part of providing ongoing services relates to the operation of those services. It is a highly specialised activity. Licensing conditions for the operation of network assets is onerous and makes it impracticable for a business to comply with where it does not have network operations as its core business[41]. Generators preference appears to be that an established asset owner own and operate any transmission assets needed for connection. This leads to a shift in the potential for the TNSP to exercise its negotiating position to extract monopoly rents to build, commission, operate and integrate them into the network.

To address these shortfalls AEMO is currently consulting on a build-own-transfer (BOT) model . Under the BOT model, the generator, being the party responsible for the funding of the investment would have the right to determine who should build the assets. The assets will need to comply with pre-agreed functional specification because they will need to integrate with the rest of the network. The functional specification will need to be agreed between AEMO and the asset owners. The ongoing maintenance and operations of the assets will then be transferred to an existing asset owner with a transmission licence.

Managing the non-contestable portions

The contestability program under clause 8.11 of the Rules[42] acknowledges that there are boundaries to what may be contestable and therefore generally applies the concept known as "separable portion". This ensures that the service that is subject to competitive tender must be able to be provided as a distinct and separate service without co-opting the incumbent asset owner to provide assistance. For example, a new terminal station is considered a separable portion of the existing network. Works to cut existing lines and re-align towers are not. The former can be done as a distinct piece of work whereas the latter cannot be done without coordinating outages with the existing asset owner. This same methodology can be similarly applied to installation of transmission assets within existing substations (such as constructing foundations and additional bus-bars, installing transformers and breakers) up until the point of going live.

There is a perception that assets designed and installed by third parties might lack interoperability with existing assets that are installed and operated by the incumbent asset owner. This introduces an additional element of risk that it does not face when it has absolute control over the entire connection process (from design to commissioning). AEMO's experience is that this risk is effectively removed by careful functional specification design and contract preparation. Tender documents for contestable projects can be written to ensure that the new assets harmonise with old and minimum performance parameters can also be specified. Finally, any risks that cannot be

[41] For instance, the Victorian jurisdiction's cross-ownership rules prohibit generators from owning transmission assets and usually operating conditions are strict and onerous.

[42] The contestability program enshrined in clause 8.11.2 of the Rules was based on the Essential Services Commission of Victoria's Guideline 18 – augmentation and land access.

effectively eliminated can be priced in by requiring a higher WACC. These principles can apply to maintenance of the assets as well.

Applying competitive provisions nationally

There are limitations that prevent competitive connection provisions being achieved nationally Most importantly, it will require a national independent party with sufficient technical expertise to oversee its management. Second, in some states there are no established process to obtain a transmission licences. Therefore, even if a generator were willing to obtain a transmission licence and build, own and operate transmission assets, it would find it impossible to do so in these jurisdictions without legislative changes.

Finally, it would require a role for the AER to review how that framework is implemented particularly where efficient "pre-build" and "right-sizing" works are appropriate. It would ensure that consistency is achieved by the planner in all jurisdictions and also report on the planner's performance by cost and performance benchmarks outcomes (such as connection delivery timing) against the planner's own performance jurisdiction-by-jurisdiction and other transmission organisations internationally.

4.2.3 Prescribed connection services

Despite the difficulties of negotiating with monopolies, if there are appropriate governance arrangements in place, the bi-lateral negotiations will deliver superior outcomes to the proposed prescribed "one-size-fits-all" approach.

The AEMC's proposal is designed to remove uncertainty from the generator's investment because the generator knows exactly the level of service that it will receive and at what cost. But a "one-size-fits-all" approach is restrictive to both the TNSP and generator and is likely to dampen innovation.

This approach is inconsistent with the competitive tendering provisions because even if the generator or third party were allowed to carry out the construction works, the generator has no incentive to do so because it will not obtain the cost benefits.

It also places the focus squarely on the provision of assets rather than moving it to the delivery of a service. This is because the TNSP will concentrate on the most effective way to provide the regulated connection service as regulated by ensuring it is backed by assets rather than concentrate on delivering the service that the connection applicant desires.

Ultimately, a generators' needs depend on size, type, location, technology and a host of other variables, that a reasonably flexible and bespoke service is often needed.

While a prescribed connection service would make cost allocation easier as regulated services, the TNSP has more freedom to allocate its connection service costs among connected beneficiaries. We explore this in greater depth later on in this submission where we discuss the concept of allowing the TNSP to allocate the costs of connections to other users where those users benefit from the connection works. This is designed to encourage a planner to incur efficient pre-build cost in anticipation of further generators and other scale efficient works concurrently with a connection application. Given the risk of asset stranding, we recommend that any scale efficiency works and pre-build is done by an independent planner that has to justify the investment under an economic cost benefit test.

A more tailored approach to establishing connections has the potential to deliver greater benefits. Discussions with generators through our Connections Initiatives works revealed that the connection process needs to accommodate generators of different technology, scale and market participation. Generators generally identify three competing imperatives:

- *Cost* – the overall cost of connecting the generation plant to the network.
- *Quality* – the additional features of a connection service that provides additional benefits to the generator over and above a standard connection service.
- *Timing* – the ability to lock in a delivery time that is consistent with the generator's business case.

In absolute terms a connecting generator can minimise one of these but not the other two. Generally, connection applicants will optimise across the three by choosing one to prioritise and optimise the other two. For example, some generators will require tight timeframes and accept significantly higher costs and lesser overall quality below the standard arrangement.

Therefore, a level of flexibility is desired to accommodate the varied requirements of generation investors. For instance, depending on the size of generation plant, some wind farms prefer the reduced costs[43] of a 'T' arrangement than a three-breaker arrangement even though the latter arrangement provides superior security benefits to both itself and to market. Therefore, requiring all generators at all voltages to be connected via three-breaker arrangement would in our view be too restrictive[44].

The flexibility that comes with negotiated outcomes can lead to costs that do not necessarily benefit the generator (in other words, they exceed the stand alone costs of the connection) and if these costs are economically justified and efficient, in order to avoid discouraging generator investment, they should be allocated to future generators (as part of their costs of connection)[45] and/or customers.

4.2.4 Other connection related matters

Right sizing and cost allocation

One of the challenges for network connections has been to connect generators in the most cost effective way possible. Balancing the requirements of new connections with network security and other requirements is difficult and as more generators connect the hurdle for subsequent generators increases. The transmission planner should be encouraged to accelerate certain investments ahead of committed generation[46] provided they are economically justified. However this can only be achieved with an independent national planner applying economic planning principles in order to provide a constraint on the level of additional investment.

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[43] Depending on the circumstances, this can provide cost saving of between $10 million and $20 million per connection.

[44] However, to ensure the security of inter-regional flows, connection arrangements with less than a three-breaker arrangement are usually not recommended for voltages of 220kV and less and depending on the circumstances may not constitute good industry practice.

[45] The framework for rebating a proportion of the connection charges of the first generator and passing them onto subsequent generators already exists in the Rules and will therefore not be discussed further.

[46] These are additional costs required to prepare for additional, future generation. They include costs of securing additional land/easements, over-sizing earth mats, blasting works to prepare the site for future uncommitted generators, tower realignments etc.

Two issues arise in this area:

- Efficient scaling
- Securing property rights

Efficiency scaling and future proofing

Efficiencies can be realised by grouping multiple connections at one substation and making better use of shared network assets by building in future growth capacity when a site is identified for connection. However, requiring the founding generator to pay for the entire cost of any scale flexibility can be a sizeable addition to its project costs and under the Rules it is unclear if those costs can be borne by the initial generator. Such an impost could also be inefficient and distort investment if it is significant. Due to this cost recovery uncertainty, the potential benefits of this type of asset planning have been lost.

There are benefits to customers and the market in general to "right-size" sub-stations in anticipation of future connections. However, to minimise the burden on private generator investors, the costs in excess of what is strictly needed for the current connection can, be legitimately allocated to customers.

The benefits of a taking a "right-sizing" approach rather than the existing *ad hoc* connection approach can be illustrated by Ofgem's consultant's report on coordinating offshore transmission connection for offshore wind farms to the national grid[47]. A number of "coordinated" connection options were considered and compared to individual radial option and each option showed a cost saving benefit over the radial approach. The justification and planning for the coordinated approach is done by Ofgem and its appointed consultants and not the owner of the land-bound transmission network, National Grid.

Accommodating future expansion raises the risk of stranding which increases the costs to customers above that which is necessary. Accordingly, care must be taken to minimise exposure to this risk. The risk of stranding can be minimised in the following manner:

- Forecasts of future generation at the connection point must be based on reasoned probability analyses regarding:
    - the location and availability of proven fuel sources (wind, solar, gas pipelines etc)
    - the location of other connection applications/enquiries in the area and other areas
    - integration of the generation into the overall planning of the network (including interconnectors)
- Staging works to reduce up-front capital expenditure. This can be done in conjunction with economic cost benefit quantification tools such as option theory and decision tree analysis. In practice land needed to expand substation sites and widen line easements can be secured at the time that the first generator requires connection but development of that land might occur until it was needed[48]. Another cost minimisation strategy is to make provision for more

[47] Coordination in Offshore transmission – an assessment of regulatory, commercial and economic issues and options, A report by Redpoint Energy Limited, p.32.
http://www.ofgem.gov.uk/Networks/offtrans/pdc/pwg/OTCP/reports/Pages/reports.aspx

[48] To reduce costs further, this could be done by securing options to purchase the land or easement rather than purchasing the land outright.

capacity (say two circuits instead of one) but defer the cost of stringing the circuit until necessary.

- An independent national planner has less incentive to over-build than one whose revenue depends on augmenting its asset base. A planner whose revenue is dependent on adding to its asset base is more likely to over-forecast and accelerates works.

Securing property rights

A major difficulty facing generators when they connect (particularly those who are located a distance from existing transmission) is securing freehold, leases and easements for their transmission related equipment. The obstacles range from topography to landowner negotiations and each has a direct effect on connection costs. The main issues revolve around securing easements with landowners and negotiating planning approval with local government.

Often generators, for example wind and solar, need to be located some distance from existing transmission and must negotiate with multiple landowners. Generally, landowners will negotiate in good faith but on some occasions, a minority will refuse to deal either on ideological grounds or to opportunistically obtain a better deal. This can substantially increase the costs of connection both in terms of paying more for the property right, accommodating more onerous conditions to the grant of the property right (e.g. imposing burdensome restrictions to site access) and by delaying projects.

These costs can be reduced by:

- ensuring that compulsory acquisition powers[49] are consistent across the NEM and consistently granted to electricity industry participants and potential participants. This is a controversial area and probably because of that, there has been a hesitation to look at the issue in depth. Some government owned and established private generators already have compulsion rights, but new generators, generally those without a generation licence, do not. Not only does this clearly create inequity between different investors but it also creates inefficiencies as prospective generators, at best, pay more than market value for the property in order to proceed or, at worse, call off a project entirely. Generally, all TNSPs have compulsory acquisition rights but will only use them for their own projects and not to support generator's contestable projects, and
- aggregating sites and easements for the use of many generators rather than a number of individual pathways. This is difficult to achieve on a case-by-case basis with the current disjointed approach to connection planning. These efficiencies are more likely to be achieved by a coordinated planning approach.

Another difficulty raised by generators is the difficulty of obtaining planning approval for the transmission lines required for connection. These can provide such a obstacle that proponents will often scaled back to a less optimal generator size to enable connection to the distribution network because the restrictions on installing new distribution lines are usually far less onerous than transmission.

Other problems such as "development fatigue" can often occur. This happens where the first proponent is granted its permit relatively easily but subsequent developers find it successively harder to obtain permits. The hesitation is more often than not caused by the fact that each

[49] This is usually granted as a last resort power where voluntary negotiations have failed.

successive transmission development adds incrementally greater capacity and therefore inevitably a new easement route whereas if the developments could be aggregated, the number of easements could be significantly reduced. Local councils would be more amenable to the transmission requirements of generation developments if a more coordinated approach were taken. This could be done quite easily if the transmission planner were to assist or take a more active role in the planning permit process.

Charging the generator for security proofing

When connections are made, certain security features must be built into the connection arrangements to ensure that the network can continue to operate safely and securely after connection as before. These security features not only benefit the generator but also benefit customers, particularly in the event of planned or forced transmission outages.

For example, multiple breaker connection arrangements not only allow a generator to continue to generate under certain planned outage conditions compared to a single breaker "T" arrangement but it also allows customers on the line to be fed from both ends of the line in the event of a fault. It affords the network operator greater flexibility to schedule planned outages and minimise disruption to both load and generators if fast reclosing features are incorporated.

Despite the benefits being spread more widely around the network, it is usually generators that are made to pay the full costs of these security features principally because were it not for the generator connection, these features would not be required. However, as pointed out in the First Interim Report there is no express basis for "causer pays" in the rules[50]. AEMO has applied a causer pays principles when connecting generators however it compromises negotiations between the generator investor and the network asset owner because the former wishes to minimise costs and the latter to secure the network. The negotiating tension between asset owner and potential generator (as mentioned above) is usually beneficial where bargaining positions are relatively equal because if a deal is reached, costs, risks and benefits are relatively evenly distributed among the parties. But when they are not it is likely to result in the generator wearing the entire costs of such security and therefore potentially stop an otherwise viable generation project from proceeding. On the other hand if the imbalance in bargaining power is sought to be redressed through the rules, say by making connection services prescribed, it could potentially lead to a degradation of security as options to deal with the connection end up being limited.

Given the current state of the Rules, it is difficult to argue that generators should face all of these costs. For instance, the costs of connecting to the 500kV transmission lines in south-west Victoria require a three-breaker arrangement to ensure inter-regional capability is not degraded. It is appropriate that connections should not degrade inter-regional flows or quality of supply to other users but there is a case to argue that some of those costs could be passed on to customers where they benefit the market in general rather than the connecting generator.

AEMO has done a lot of work on cost allocation as part of the Connections Initiatives[51] where the connection costs faced by the initial generator are rebated and passed onto subsequent generators. However, the Rules could be clearer to enable apportioning some costs to customers if determined by an economic cost benefit test.

[50] First Interim Report, p. 161

[51] http://www.aemo.com.au/planning/connection_initiatives.html

4.3 Network Planning

The First Interim Report identified a number of options for enhancing and further options for reforming the current regulatory regime in respect to network planning. AEMO's comments on each of these have been set out below. In general, while AEMO supports moves to increase transparency and consistency, these changes can only be considered interim steps towards addressing the problems with the transmission development framework. The need for an independent national transmission planner has been raised in previous sections. This is as important as ever given the challenges faced and the need to efficiently develop the national grid as a single national network.

4.3.1 Options for enhancement

A national framework for transmission network reliability standards

The AEMC has raised a previously made a recommendation to the MCE to introduce a national framework for transmission reliability standards for load. The AEMC suggests in this enhancement that a national framework for transmission reliability standards that are economically derived but deterministically expressed (a "hybrid" form of standards) will provide efficiency and competition benefits.

As discussed below AEMO believes that there are deficiencies with a hybrid planning standard, namely, that the standard is expressed as a redundancy standard encouraging the development of network solutions. Further, AEMO's recent work for ESCOSA on the South Australian standards has highlighted the difficulty of applying the approach to the meshed part of the network. This would make its application in more meshed regions difficult and complex. To overcome these complexities simplistic assumptions would need to be made rendering the approach no different to the typical N-X approach to planning.

AEMO therefore does not consider that a national hybrid approach is the optimal solution.

Improving the consistency of the APRs

AEMO supports all moves to improve the consistency of APR's. To that end, AEMO supports the production of a single national APR or an integrated national suite of information. This approach will aid transparency and enable large network customers and generators to compare the performance of all networks on a consistent basis. It would also allow intending participants to obtain a more comprehensive and national view of impending network constraints and proposed network augmentations.

Should a single national APR not be possible, AEMO supports improvements in the type and level of information that should be included in the APRs. The role of the APR in the revenue setting process has decreased over time with only tenuous links. The role of the APR process should therefore be to:

- provide the energy industry information on current network service capability and emerging constraints
- inform potential non-network suppliers of upcoming investment opportunities
- inform new generators and large loads of issues associated with possible connection locations

- provide regulated network users with an understanding of where, how and why their money is being spent and facilitate the comparison of the APR proposals with the revenue resets

In relation to the capability of the network, AEMO envisages that the information that would be included would inform the market about the power transfer capability of transmission network, fault level information, and reactive service capability. Future network requirements would include information about augmentations, including specific redundancy standards driving augmentation needs, shortfall period and duration and a valuation of the shortfalls using an appropriate willingness to pay method.

Greater scrutiny would also be required of the replacement programs and a detailed justification for the need of the replacement program. Replacement programs constitute between one-third and one-half of recent capital expenditure programs however there is limited transparency and no justification or consultation processes on the need for replacement programs. Information would be supplied on what the consequences would be if the replacement program were not to proceed.

Information to non-network service providers would be more clearly specified for each augmentation. This is expected to include the type of service, in either MW or MVAR, the location of the service and the duration for which the service is required, noting that in some instances the detail will only be specified in a RIT-T.

For generators and large loads considering investments, AEMO envisages additional information would be required including possible network connection costs if locating at specific points, the power transfer capability and constraints at possible connection points and loss factor information.

Importantly, the information in an APR should be linked to the price effects on consumers. Therefore comparison of load forecasts used in revenue reset and APR load growth assumptions would need to be clearly set out. Further, comparison of projects and operation decisions presented to justify revenue reset and APR projects identified. Any changes or deviations from the revenue caps would need to be more clearly specified.

Improving transparency when applying the RIT-T

The current RIT-T guidelines require greater transparency of TNSP investment decisions and AEMO supports continued review of the transparency provisions to ensure that it is meeting the needs of network users. AEMO supports being less prescriptive in the NER and supports moves to provide the AER with greater flexibility on the specification and detail contained within the RIT-T.

AEMO believes that the current RIT-T has one major limitation. The main one being that it presently only considers what are generally defined as partially equilibrium benefits. As demonstrated by AEMO's work on NEMLink, this approach is likely to significantly underestimate the value of the true economic benefits of network augmentations. AEMO supports changes to enable general equilibrium benefits to be included.

While there was a well founded aim to align the tests within the RIT-T to a single test, until mandated redundancy standards are removed, there will always be a requirement for the test to effectively contain two-limbs. To that end, there are some inconsistencies in the drafting of the RIT-T which are biased in favour of redundancy based planning requirements.

The RIT-T also uses the terminology between assets and services interchangeably. This must be addressed to avoid confusion it is application.

Aligning TNSPs' regulatory resets

AEMO supports aligning TNSP regulatory resets. While there may be an additional cost burden imposed on the AER, this would be considered minor compared to enabling the AER to conduct its assessment on a 'whole of network' basis. This will ensure that it can undertake meaningful benchmarks between the TNSPs on matters such as cost estimates, consider cross-border options to address state-based redundancy standards. It will also enable the AER to prepare a national service standard that can be applied across the national grid.

Reliability standards for interconnectors

The major problem with developing a truly national grid arises from the lack of responsibility and accountability for national grid development. Therefore no individual party is responsible for maintaining or improving the capability of interconnectors.

This option does not work without providing the accountability and responsibility to an independent national planner

It is important that governance with accountability and responsibility is placed within frameworks to ensure delivery and success of the framework[52].

Until such time that this problem is addressed interconnector reliability standards will not provide any changes.

4.3.2 Enhanced coordination of the NTNDP and APRs

In this option the AEMO proposes to strengthen the links between the NTNDP and APRs "without the need to devolve planning responsibilities from existing jurisdictional bodies." [53]

AEMO notes that there is already significant coordination between the TNSPs already particularly where a national response to delivering economic benefits appears to be more efficient than a local one the NTNDP explores solutions to network limitations without regard for regional borders. For example, AEMO, ElectraNet, and TransGrid are jointly considering the reliability of the South Australian Riverland area and exploring cross-border solutions between Victoria, South Australian, and New South Wales.

With the exception of the proposal that the TNSPs and AEMO endorse one another's documents, this proposal will not change current practices.

Therefore, it is unclear what the AEMC are attempting to achieve with this proposal and appears to reflect a limited understanding of current practices. Additionally, in this option the AEMC have made some comments which appear to suggest that AEMO is not an independent organisation.

> In Victoria, however, there is no such independent review, as the jurisdictional planning function and the NTP function are undertaken by the same entity[54].

As the AEMC is aware, AEMO is constituted as an independent organisation with an independent board. The decisions of AEMO are guided by the legislative obligations set out in the relevant sections of the National Electricity Law, the same place that sets out the AEMC's obligations.

[52] PRINCE2, 2007, *Comparison of Project Management Standards*, The APM Group Limited

[53] First Interim Report, p. 140

[54] Ibid, p. 141

4.3.3 Harmonised regime based on current South Australian arrangements

Financially Motivated TNSPs

The AEMC recommend implementing a harmonised set of transmission planning arrangements across all jurisdictions. It notes that the Victorian arrangements are different and posits that

> That financial incentives are likely to provide the most robust and transparent driver for efficient decision making[55]

AEMO supports marked based outcomes. It is the market that will deliver the $120 billion of generation investment that is required over the next 20 years, and the market will also drive technological evolution.

As noted in section 2, the current method of regulation is designed around an entity being responsible for meeting current and forecast needs of customers within a defined geographic boundary. It undertakes transmission expansion to meet that growth while maintaining its reliability obligations to customers which are usually stated in terms of redundancy standards.

The evidence provided by AEMO suggests that this approach has not delivered the benefits postulated by the AEMC.

Inefficiencies of reliability planning in South Australia

Notwithstanding the lack of evidence, the AEMC recommends adopting what is generally known as the 'South Australian' approach.

AEMO, in one of its adoptive jurisdictional functions, is intimately aware of the details of the South Australian approach. It is an approach that can be characterised as having independent state demand forecasting, and a redundancy planning standard which has been informed by probabilistic planning methods.

These are explored in turn below.

- Independent Forecasting

One of the main components of the revenue setting arrangements is the demand forecasts. Demand growth, coupled with the redundancy planning standards, drives up to two thirds of a TNSPs capital expenditure program in any year.

Under the revenue setting arrangements, there is a clear incentive for the TNSP to over-forecast demand requirements. In this context, the benefits of independent demand forecasting become obvious and are best considered by way of example of where there is no independent oversight of demand forecasts.

Figure 9 presents Queensland's summer 1 and 2 year-ahead 10% probability of exceedence (POE) maximum demand forecasts over the past 10 years. It also plots actual summer maximum demand. It suggests that there has been a consistent over-forecasting since 2004-05. The effect of this, if it has been accepted by the AER as a true and accurate forecast could be up to 1000 MW of additional transmission capability built into the Queensland system.

[55] Ibid, p. 143

Figure 9 - Queensland Demand Forecasts vs actual – 2000-01 to 2011-12

Source: AEMO

On this point, the AEMC has highlighted a comment made by the Northern Generators Group about AEMO's incentive to over forecast demand.

As the AEMC and the Northern Generators are aware, up until 2011, all demand forecasts were supplied by jurisdictional planning bodies, AEMO, in Victoria and South Australia, Transend in Tasmania, TransGrid in NSW and Powerlink in Queensland. AEMO has been criticised for its approach of simply collating and repackaging the demand forecast supplied by these bodies particularly given the extent of the over-forecasting in NSW and Queensland in particular.

As a result, by June 2012 AEMO will produce an independent national electricity forecast. This will enable it to critically analyse the changing conditions in the electricity and gas markets, the effects of solar PV penetration rates, the responsive of consumers to rising electricity prices and the influence of new technology such as electricity vehicles on peak demand.

- Hybrid Planning

As already mentioned South Australia uses a redundancy planning standard informed by probabilistic parameters. The Value of Customer Reliability (VCR) is used to inform the deterministic standard and is taken into account in the reliability standards for longer-term planning requirements. It requires assumptions to be made many years in advance of the likely augmentations to address an emerging constraint.

Load connection points are allocated into one of six reliability categories which are designed to capture the economics of supplying individual connection points vary through both the value of lost load and particularly the cost to provide a given level of reliability.

The South Australian legislation requires that connection point reliability cannot be reduced from that at privatisation. The probabilistic approach is used to compare the cost of increasing reliability standards of a connection point to the next deterministic reliability level with the value of the increased reliability delivered to the connection point.

This approach delivers better outcomes than those of a strict N-X approach because it identifies different levels of reliability according to demand for each connection point and considers a VCR when determining the level of reliability required at a particular connection point. It also allows an independent body to establish and audit the arrangements.

However there are also some significant inefficiencies of the SA model.

Firstly, it is difficult to apply in regions with a large number of connection points or a more meshed network, that is, where a connection point is interconnected to many other connection points within the network.

There is complexity to determine the base reliability levels for these highly meshed types of networks occur. South Australia is predominantly a radial network, however the recent reliability standards review work by AEMO has identified that some connection points located in a more meshed area make defining the level of reliability through connection point standards difficult.

A further inefficiency of the SA model is the potential to trigger additional network investment to maintain the existing level of redundancy rather than the true requirement of consumers at that point. While this is a legislative requirement, there are several connection points where a lower category of reliability would now be sufficient to meet the needs of customers. In these cases, maintaining the current standard is imposing unnecessary costs on consumers.

It can also produce some inconsistencies between connection points, particularly those located close to interconnectors. The methodology treats interconnectors similar to generators however in the case of Murraylink are unavailable to supply SA during peak demand. AEMO recommended in the recent review that Murraylink support for the Monash connection point load be based on a reduced capacity calculated using the operational Murraylink limit assuming Victorian peak demand times.

However for connection points where local generators exist full availability is assumed, therefore the reliability level at connection points located near generators can be inconsistent with the methodology used to determine the reliability level at connection points closer to the regional boundaries or other specifically identified supply issues.

Another inefficiency of the SA model includes the accuracy of the cost estimates for augmentations used at that point in time. That is, a review of reliability levels is performed every five years for each connection point using NPV analysis to determine whether the benefits of a network augmentation required to increase the level of reliability outweigh its costs. If the review produces a positive NPV, using cost estimates provided by the asset owner, then it is recommended to move to the next reliability category through augmentation.

The options of augmentation to achieve this next reliability level are required to undergo RIT-T assessments under the reliability limb of the Rules. If there is a difference in cost estimates used in this cost-benefit analysis, the augmentation which produces the least negative value is accepted which can offset the initial assessment. This places a risk on the hybrid model that cost estimates provided by the asset owner for cost-benefit analyses could be skewed.

A review of reliability levels every five years will also cause a duplication of analysis, and potentially conflicting results, with that required under a RIT-T assessment at the time of investment. If a RIT-T investment shows a reliability-based investment has a negative net benefit then this indicates that circumstances have changed since the original assessment of the reliability level and that the reliability level is no longer the most efficient.

Therefore, performing the cost-benefit assessment twice produces inconsistencies in the benefits resulting from reliability-based investments between the current RIT-T process and the review in South Australia

4.3.4 A single NEM-wide transmission planner and procurer

The Victorian DPI proposal to extend AEMO's role nationally is examined in this review. This option considers giving AEMO new activities including:

- performing all transmission network planning across the NEM;
- making all transmission investment decisions in the NEM as a not-for-profit entity;
- procure most new transmission services, including non-network services, through a competitive tender process; and
- apply the probabilistic planning methodology that is currently applied in Victoria to assess the need for new investment.

The benefits of a national perspective have been highlighted earlier in this submission. Another example can be found AEMO's wind integration studies.

AEMO's wind integration work notes the benefits to the national grid and the cost of meeting the mandatory national Renewable Energy Target of considering the optimal placement and connection of wind across the NEM. Consultants EcarEnergy discuss the advantages of grouping wind energy projects into one technical solution noting the benefits in Texas and Ireland[56 57]. The AEMC proposed such a role for AEMO in its Climate Change review and the SENE rule change proposal, prior to recommending that the critical issues be addressed in this Frameworks Review.

AEMO's modelling on the cost of gas transmission pipelines has highlighted the benefits of better coordination between gas and electricity transmission infrastructure development. Many gas transmission pipelines cross state boundaries limiting their consideration in cost-benefit tests. AEMO's future modelling will attempt to co-optimise the development of gas transmission and electricity transmission infrastructure highlighting the benefits of a national perspective.

The benefits of a national independent planning also enables a more service focused regime to be put in place, specifically the use of an economic cost- benefit assessment that focuses on delivering services.

The benefits of an independent planner have been provided earlier in this submission.

This point has been acknowledged by the Hon Martin Ferguson AM MP who recently stated in his address at the Press Conference for the Draft Energy White Paper launch that the success of the Victorian arrangements "speaks for itself"[58].

4.3.5 Joint-venture planning body established by TNSPs

The AEMC is proposing in this option that existing TNSPs establish a joint-venture body that would assume all the rights and obligations associated with being a TNSP across the NEM. The physical ownership of the networks would be retained by individual TNSPs.

This option would create a for-profit national planner, thereby moving the decision making responsibilities away from AEMO. The option is only briefly outlined and the proposed structure, governance and accountability of this proposed body is not described.

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[56] Energynautics GmbH, Lessons Learned from International Wind Integration studies, Germany

[57] Ecar Energy, Wind Integration In Electricity Grids: International Practice And Experience, 2011

[58] The Hon Martin Ferguson AM MP, Transcript Press Conference for the Draft Energy White Paper launch, 13 December 2011

However, as demonstrated in above, the financially motivated regulated business model has not delivered efficient outcomes compared with the not-for-profit approach adopted in Victoria. It is difficult to see then how adopting this option would provide a more efficient solution and meet the National Electricity Objective.

AEMO agrees that efficiencies that can be derived from a framework which aligns the incentives of a market or regulatory regime with the commercial interests of financially motivated businesses. The evidence presented above and scrutiny of the existing regulatory framework provides evidence that the current regulatory framework for transmission services does not drive dynamic efficiency through incentivising efficient long term investment. The application of the RIT-T and the various regulatory requirements for reporting and planning are a poor substitute for the incentives needed. AEMO considers that it is not possible to design such incentives given the nature of transmission investment and investment in a network. As a result, we consider that a single NEM-wide transmission planner and procurer represent the preferred option.