Andrew Truswell
Australian Energy Market Commission
Level 5
201 Elizabeth Street
Sydney NSW 2000
By online lodgement on www.aemc.gov.au

27 January 2012

Dear Mr Truswell,

Re AEMC Reference EPR0019 – Transmission Frameworks Review First Interim Report

International Power-GDF Suez Australia (IPRA) appreciates the opportunity to comment on the Transmission Frameworks Review First Interim Report. We also thank the AEMC for publishing our preliminary submission in advance of the submission closing date, to enable other parties to comment on our alternative proposal.

Network access arrangements are of critical importance to generating businesses in the NEM, and we are hopeful that this important review leads to more commercial, market driven arrangements.

Should you have any enquiries regarding this matter please do not hesitate to contact either myself or David Hoch on 03 5135 5363.

Yours sincerely,

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IPRA Submission to AEMC Transmission Frameworks Review First Interim Report

(AEMC Reference EPR0019)

27 January 2012

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Table of Contents

1 Introduction 4
2 Executive summary 5
3 General perspective of this submission 7
4 Why is change to the current framework needed? 8
4.1 IPRA's key concerns with the current transmission frameworks 8
4.2 Heywood Interconnector capacity and constraints in South-East South Australia 8
4.3 Yallourn connection to the 500kV transmission network in Victoria 10
4.4 Basslink 11
4.5 Inter-regional trading in the NEM 11
4.6 Significant transmission events and the cost of constraints 13
5 Desirable features of a transmission framework 16
6 Why each of the 5 options fails to satisfy the proposed features 18
6.1 Option 1 – "Open Access" 18
6.2 Option 2 - Open Access with Congestion Pricing 19
6.3 Option 3 - Generator Reliability Standards 19
6.4 Option 4 - Regional Optional Firm Access 20
6.5 Option 5 - National Locational Marginal Pricing 21
7 Integrated package of framework elements 23
7.1 Protection of agreed access 23
7.2 Locational signal for new generators 24
7.3 Choice of level of access 25
7.4 Ability to trade access 27
7.5 Congestion management 28
7.6 Interconnector planning to maintain a sufficiently integrated NEM 30
8 Alignment of proposal with desirable features 32
8.1 TNSP incentives for investment and operation 32
8.2 Generator incentives 32
8.3 Coordination between transmission and generation 33
8.4 Safety, reliability and security of system maintained 33
8.5 Existing generators not disadvantaged 33
9 Clarification of issues raised by the integrated proposal 34
9.1 The uncertainty of network limits 34
9.2 Deep connection charges and economies of scale in transmission 35
9.3 The measurement protocol 37
9.4 No discrimination by market operator 39
10 Costs of implementing this package 40
10.1 AEMO 40
10.2 AER 40
10.3 National Transmission Planner 40
10.4 Network Service Providers 40
11 Relationship to existing Rules 42

11.1 Protection of agreed access 42
11.2 Locational signals through charging deep connection costs for new entrants 42
11.3 Choice of level of access 43

12 Distraction affecting consultation process 44

13 Comments on proposed planning arrangements 44

13.1 Current planning model not aligned with competitive market 44
13.2 Planning outcomes should promote market competition 45
13.3 Inter-regional planning 45

14 Comments on proposed connection arrangements 46

14.1 General discussion on connection arrangements in the NEM 46
14.2 Comments on the connections options presented by the Commission in Chapter 13 of the interim report 47

15 Glossary 48

Appendix 1 – Summary of relevant Rules 49

Rule 5.3 (establishing or modifying connection): 49
Rule 5.4A Access arrangements relating to Transmission Networks 49
Schedule 5.1 Network Performance Requirements 49

Appendix 2 – Planning arrangements 50

Extract from IPRA Submission to AEMC Issues Paper 50
Extract from IPRA Submission to AEMC Directions Paper: 54

Appendix 3 – Evidence of large uncertainty in network limits 56

1 Introduction

International Power-GDF Suez Australia (IPRA) welcomes the opportunity to comment on the consultation that the Australian Energy Market Commission (AEMC) is conducting on transmission frameworks in the NEM.

International Power entered the Australian energy industry in 1996 and has grown to become one of the country's largest private energy generators, with assets in Victoria, South Australia and Western Australia. The International Power portfolio also includes Simply Energy, a significant second-tier gas and electricity retail business.

In February 2011, International Power combined with GDF SUEZ's energy assets to form a world leader in independent power generation, with more than 72,360 MW of power generation worldwide and further 15,503 GW under construction.

Together with power generation, GDF SUEZ is also active in closely-linked businesses including LNG terminals, gas distribution, retail and desalination.

At the request of the AEMC, IPRA provided a preliminary version of our submission on the transmission frameworks review on the 16 January 2012, which was then published on the AEMC's website. This was done to enable other parties to comment on IPRA's alternative proposal. Although this full submission is broadly consistent with our preliminary submission, this full submission supersedes our preliminary submission.

2 Executive summary

What is the problem?

The effective integration of regulated transmission networks and the competitive wholesale market has proven to be challenging for NEM designers, and remains as "unfinished business" some 14 years following NEM commencement. IPRA commends the AEMC on preparing an extensive interim report examining a range of options to consider.

The challenges include creating incentives for TNSPs to invest efficiently to support the competitive generation sector, providing effective locational signals for new generation and maintaining investment certainty for existing and future investors.

It is important that we make progress and improve the transmission frameworks, because the current arrangements:

- are ambiguously defined in the Rules, with TNSP practice varying across the regions;
- are not consistent with the original intent evident in the Rules (specifically they fail to protect access and overall transmission capability);
- cannot deal with the imminent increase in new connections arising out of clean energy policy;
- do not provide effective and complete locational signals for new investment;
- impose commercial risks on generators without effective means of mitigating these risks[1];
- do not successfully manage congestion and create incentives for so-called "disorderly bidding"; and
- do not protect generator access or allow generators choice of level of access.

IPRA proposes an integrated package

IPRA proposes an alternative integrated package of comprehensive reforms which are compatible with the roles and structures of the TNSPs, and are consistent with the current Rules and the intent of the original NEM design.

In summary, our integrated package:

- allows generators to choose the level of network access they require, and then pay the TNSP for any necessary network augmentation;
- requires the TNSP to maintain (protect) this agreed level of access following entry of any subsequent new generator connections;
- applies similar discipline on the maintenance of interconnection capability; and
- removes incentives for disorderly bidding by introducing congestion management arrangements similar to those described in the AEMC's first interim report.

[1] For example, generators network access can be restricted by new connections, with no effective means to respond. Equally, there are no real incentives on TNSPs to provide connecting parties with the access provisions that they seek.

What are the benefits of the integrated package?

IPRA recommends this integrated package as it will:

- provide strong and effective locational investment signals;
- enable efficient generator investment and operation through agreed access arrangements and congestion management;
- provide coordination of TNSPs and generator responsibilities, without imposing unmanageable costs or risks on either sector;
- not impose new TUOS charges on existing generators; undermining the basis of acquisition or investment;
- Reduce the progressive regionalisation of the market by maintaining interconnection capability; and
- be more strongly aligned with the NEO.

If implemented, the integrated package will achieve all of the desirable features of a transmission framework listed by the AEMC in its first interim report, as well as the additional desirable feature identified by IPRA. This would lead to significant improvements in the overall efficiency of the NEM and improved risk management arrangements, without imposing any major structural changes or risks.

3 General perspective of this submission

In this submission, in relation to the issues of generator access to the transmission network and interactions between network and the market, IPRA will review the options proposed in the first interim report and will propose an alternative designed to better match the features that the Commission has proposed that the frameworks should provide.

IPRA's alternative integrated package is recommended as a pragmatic way to resolve a number of current issues, but is not an ultimate solution.

IPRA stresses that in its view, one of the ultimate objectives of the Australian Transmission Framework must remain the ability for generators to be able to manage all of their risks due to congestion and pricing events, and make economic decisions regarding the risk/cost trade-off for their business circumstances.

However, we recognise that this ideal has proven difficult to achieve, and have therefore focussed on improvements that are readily achievable in the short term. At a later time it may be appropriate to consider additional mechanisms for generators to secure higher levels of risk assurance, after the materiality of residual generation financial risk resulting from the present proposal can be assessed.

When major transmission events occur (e.g. multiple transmission outages due to bushfires, or multiple contingency transmission events such as the examples detailed in section 4.6 below), market participants are exposed to potentially devastating financial risks with no effective means of mitigation. Although the integrated package described in this submission does not address these risks, IPRA is firmly of the view that a mechanism to manage these risks should be an integral part of the transmission framework, and recommends that consideration of the need for more specific risk management mechanisms for these events should occur promptly.

We believe the forms of so-called "firm access" proposed in the first interim report are flawed as will be seen from our detailed comments. But worse, apart from their flaws, they share the common characteristic that they designate the access level of existing generators as being "non-firm", and then require generators to pay for a higher level of access. This "non-firm" status is worse than the reasonable expectations of these generators, based on the current Rules, and hence such schemes constitute the imposition of a new regulatory risk. We contend that this imposition would be inconsistent with the National Electricity Objective.

Our integrated package addresses the economic efficiency principles underpinning the NEO, perceptions of equity between new and existing generators and the reasonable expectations of existing generators, by drawing significantly on the evident but unrealised intent of the existing Rules. Additional detail has been provided so that this intent can be applied as workable and consistent Rule provisions.

4 Why is change to the current framework needed?

With commercial and operational experience in the NEM since its commencement, IPRA is well placed to offer insights into the effectiveness of the current transmission frameworks. Our comments on the Transmission Frameworks Review (TFR) have been guided by this direct experience.

4.1 IPRA's key concerns with the current transmission frameworks

Our concern with the current transmission frameworks can be summarised as follows:

- the commercial risks associated with the availability and performance of the transmission system are not borne by the parties best placed to manage them, i.e. Transmission Network Service Providers (TNSP). Instead the risks fall heavily on generators and retailers who have limited ability to manage them;
- there are no mechanisms in the Rules to enable these risks to be effectively managed by generators and retailers, resulting in additional costs;
- there is no defined level of transmission access for new or existing generators to either intra-regional or inter-regional markets; and
- transmission access within regions and between regions varies over time, and there is no protection from degraded access (nor any compensation if access degrades).

These factors are critical in an environment where energy policy is moving toward limited or no new public investment in generation. Left unresolved, they undermine investment confidence in generation and run counter to government objectives to encourage private investment in new generation projects.

Generators currently receive common or shared access to the network, which is developed by evaluating the perceived collective interests of the market as a whole from a customer perspective (RIT-T). A generator however evaluates market benefits by considering its level of production and the market price.

Since the RIT-T deliberately ignores market prices (which lead to wealth transfers) and considers only changes in production costs; the current regulatory test is quite indifferent to the generators' commercial returns. As a result it does not provide generators with the transmission services that they need to operate efficiently and effectively in a competitive market.

The following examples illustrate our concerns with the current transmission frameworks in the NEM.

4.2 Heywood Interconnector capacity and constraints in South-East South Australia

IPRA has observed a decrease in the Heywood interconnection capacity, particularly for flows from Victoria to South Australia (i.e. the export limit). This downward trend has become pronounced over the last several years and has coincided with a large increase in wind generation in South Australia, and the commissioning of the South East to Mayura to Snuggery line in South Australia (December 2007).

This vanishing Heywood interconnector capability is highlighted by Figure 1 which shows the average quarterly limits on the interconnector from 1999 to the 2011. The export limit is shown by the red line and the downward trend is obvious.

The South East 132kV transmission system in South Australia supplies loads in the South East region of South Australia and has generation at Snuggery (gas turbines and a distribution connected wind farm at Canunda), Lake Bonney (wind farms) and Ladbroke Grove (gas turbines).

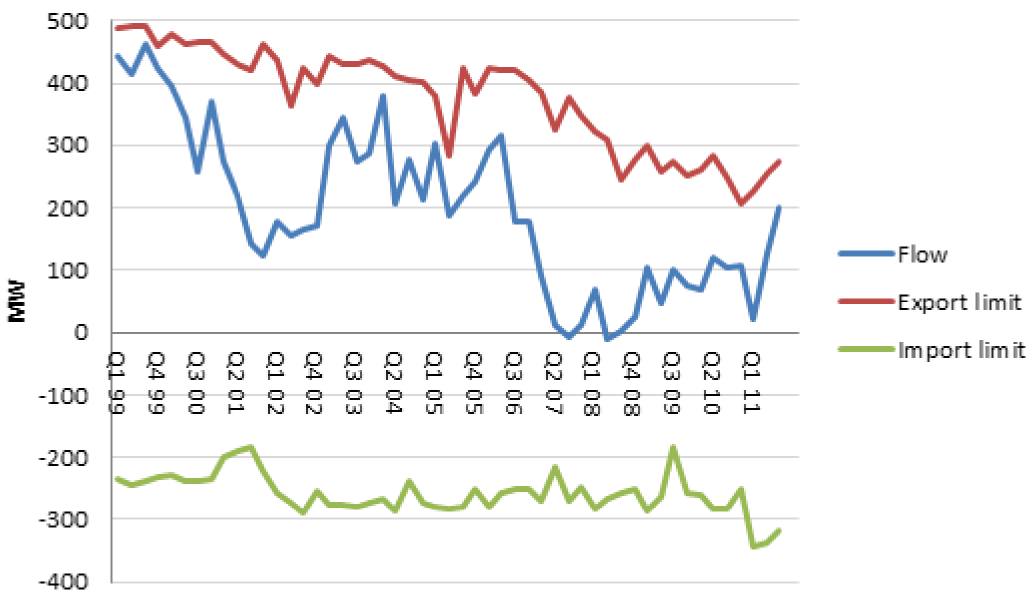
The gas turbines at Snuggery (78MW) were installed in 1980, the gas turbines at Ladbroke Grove (86MW) in 2001, Lake Bonney Stage 1 wind farm (81MW) and the Canunda wind farm (46MW) in 2005, Lake Bonney Stage 2 wind farm (159MW) in 2008 and Lake Bonney Stage 3 wind farm (39MW) in 2010.

From 1980 to 2001, there was 78MW of generation in the South East 132 kV transmission system in South Australia. By 2008, this has increased to over 400MW and is now 489MW with the increase almost exclusively due to new wind projects.

Load in the area has not grown as rapidly and this has created conditions where South East generation is frequently greater than local load and hence is exported via the transmission network to supply demand more widely in South Australia and Victoria.

These changed circumstances have created transmission congestion problems which need to be managed by the Australian Energy Market Operator (AEMO), and impact on other generation in the area and also the Heywood interconnector between Victoria and South Australia.

Figure 1: Heywood average quarterly interconnector limits (1999-2011)



Assuming system normal conditions, when power is flowing from Victoria into South Australia on the Heywood interconnector, the overloading of a South East 275/132 kV transformer would occur if the second transformer under conditions of high import, high load and low 132kV connected generation.

Conversely, when power is flowing in the opposite direction into Victoria on the Heywood interconnector, the level of generation in the South East 132 kV sub-network is occasionally constrained at times of low load and high wind to ensure operation within thermal limits of South East 275/132 kV transformers.

Since December 2007, the main constraint equation related to overloading a South East 275/132kV transformer for the loss (trip) of the other South East 275/132 kV transformer has bound for an average of 56 hours per month. This problem has been acknowledged by both ElectraNet and AEMO.

Interconnector limits have a profound impact on market operation. The reduction in interconnector capability reduces the reserve available to South Australia from other NEM regions, and South Australia's ability to access cheaper inter-state power. From a commercial perspective, this undermines confidence in inter-regional trading and therefore reduces contract liquidity.

As the company with full commercial responsibility for the Snuggery Power Station for over a decade, IPRA offers this case study as an example of the difficulty it has experienced in relation to transmission access for Snuggery under the current transmission frameworks, where access is rationed without compensation as a result of congestion.

This integrated example highlights how new investments in generation and transmission undermined the level of transmission access for generators in South East in South Australia, and also degraded the interconnection between Victoria and South Australia.

4.3 Yallourn connection to the 500kV transmission network in Victoria

To reduce the marginal transmission loss factors on the 220kV transmission network between the Latrobe Valley and Melbourne in Victoria, Unit 1 of the Yallourn W power station was switched to the 500kV network at the Hazelwood terminal station. This was made possible by applying a loose interpretation of the (strictly undefined[2]) "open access" regime as allowing one generator's access cost (through congestion and loss factors) to be imposed on another generator.

In Yallourn's case, Unit 1 already had access to the 220kV network and was granted a unique privilege of choice between connecting to two separate parts of the transmission network at their competitors' expense.

The new arrangement resulted in increased transmission losses for Hazelwood and Jeeralang power stations which negatively impacted their bottom line (reduced revenue). Separately it increased congestion of the 220/500kV transformation, further impacting Hazelwood and Jeeralang power stations.

2 "Open access" is often quoted as a NEM principle but remains undefined in the Rules.

This example highlights how transmission access was degraded for Hazelwood and Jeeralang power stations without compensation. This change to the level of transmission access for Hazelwood was unforeseeable at the time of purchase for IPRA.

4.4 Basslink

At the time of the connection of Basslink, it was acknowledged that a better economic result would have been to connect to the mainland near Western Port instead of the Latrobe Valley. However there were no effective signals to achieve this and the proponents of Basslink took the least cost route. The TNSP used a loose interpretation of the open access regime (undefined in the Rules) to facilitate this connection.

At times of high Victorian demand when Loy Yang B, Loy Yang A and Valley Power are generating and Basslink is flowing into Victoria, transmission congestion arises and access is rationed to manage congestion. To compound the problem, the current bidding arrangements for scheduled market network services can be used in a manner which gives Basslink dispatch priority over some Victorian generation. A rule change has been lodged with the AEMC recently by IPRA seeking to prevent Basslink from exploiting a loophole in the current Rules.

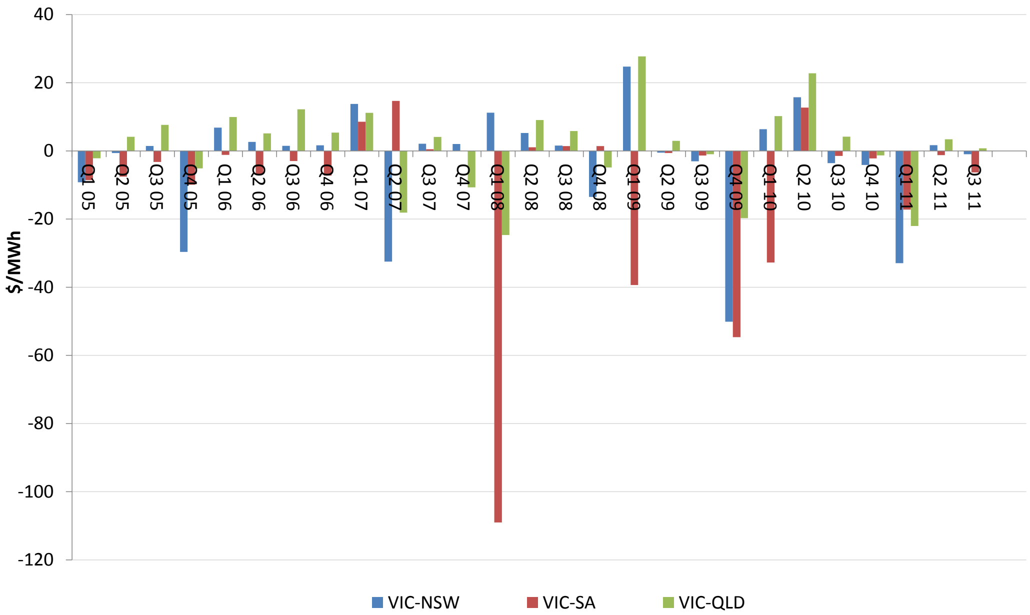
This example highlights how transmission access has been degraded for incumbent Victorian generators following the commissioning of a transmission asset designated as a Market Network Service Provider.

4.5 Inter-regional trading in the NEM

The three charts that follow show the average quarterly price differences between Victoria and New South Wales, South Australia and Queensland. (The price differential is relative to the Victorian price. Hence a positive number indicates a higher price than Victoria, and *vice versa*).

Figure 2 shows the difference between the time-weighted average (base load) prices for Victoria and the other three regions.

Figure 2: Quarterly base price differentials relative to the Victorian RRP



The next two charts break this down further to look at the time-weighted average differences for peak and off peak time periods.

Figure 3shows the price differences for peak periods (half hours ending 7:30am-10:00pm EST on weekdays excluding public holidays)

Figure 3: Quarterly peak price differentials relative to the Victorian RRP

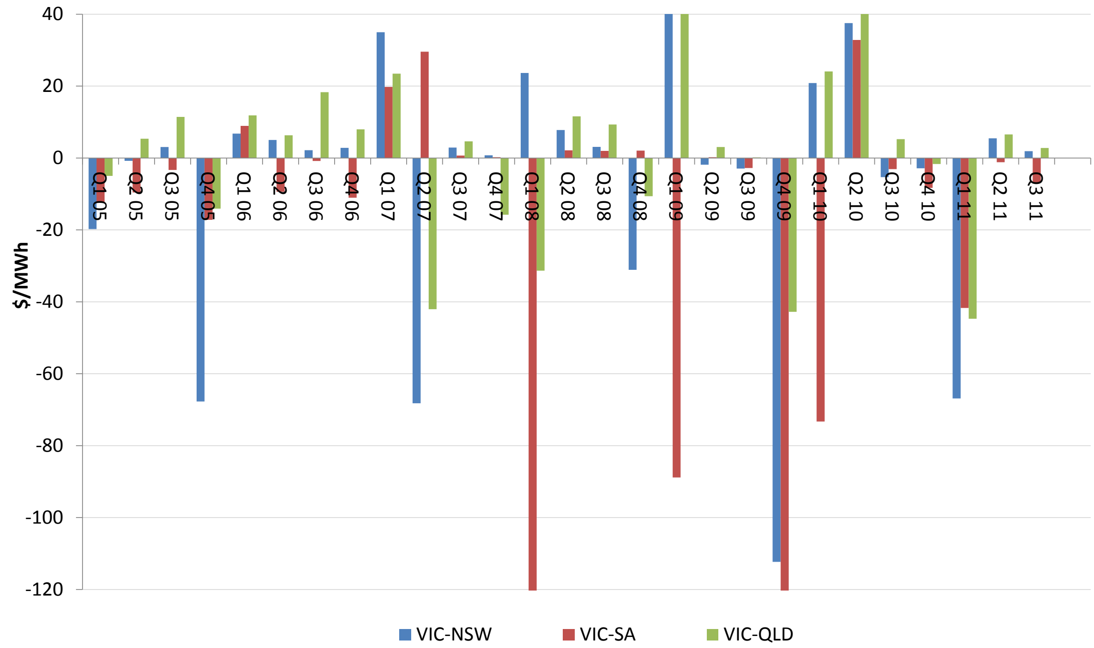
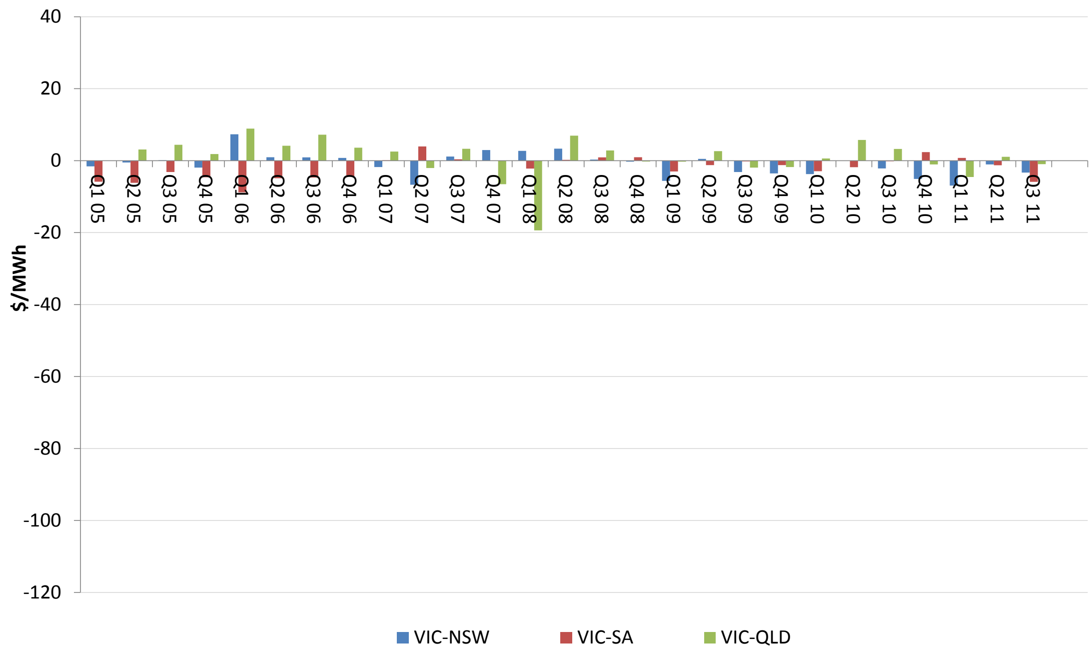


Figure 4 shows the price differences for off-peak periods (half hours ending 10:30pm -7:00am EST on weekdays, and all half hours on weekends and public holidays).

Figure 4: Quarterly off peak price differentials relative to the Victorian RRP



These three charts show that there are typically quite small price differences between Victoria and New South Wales, South Australia and Queensland during off-peak periods. However, during peak periods, the price differences are highly volatile and the overall average price differences are also volatile.

Price differences between regions are inevitable and economic due to differences in generation technologies and fuel sources. Price differences themselves are not a problem, but rather their highly volatile nature. A major component of this volatility is introduced by transmission congestion – both within regions and between regions.

This overall price difference volatility is a deterrent to inter-regional trading. A generator or retailer that seeks to contract in a region outside its own faces significant risks if it is left unable to defend these contracts in the event of transmission congestion or inter-regional separation.

The settlement residue auction (SRA) process for interconnectors is intended to provide a mechanism to manage this risk. However it is unable to do this effectively because the auctions are linked to the physical availability of interconnectors with highly variable capability. Unpredicted changes in the physical availability of interconnectors therefore undermine the ability of these products to adequately manage inter-regional trading risk.

The ability to trade power contracts between regions with confidence is a highly desirable outcome for the NEM. To do so currently requires a market participant to bear significant inter-regional price risk. A large component of this price risk is related to transmission, over which generators and retailers have very little or no control

4.6 Significant transmission events and the cost of constraints

A substantial portion of transmission costs for generators are incurred during significant transmission network events.

Recent examples of significant transmission events include:

- 12 Dec 2002 Dederang-Murray line trip
- 27 May 2003 Heywood-South East line trip
- 8 March 2004 South Australia bushfires
- 14 Mar 2005 Davenport to Playford line trip
- 16 January 2007 Victoria bushfires
- 23 July 2008 Loy Yang to Hazelwood line trip
- 29 Jan 2009 Hazelwood Terminal Station transformer outage
- 8 Feb 2009 Victorian bushfires
- 19 Oct 2011 Heywood to Moorabool to Portland line outage

Further discussion of two of these events is provided below:

16 January 2007

Bushfires caused the simultaneous trip of two transmission circuits of the interconnection between New South Wales and Victoria under conditions of low reserve due to hot weather.

This was followed by cascade tripping of six other transmission lines, fragmenting the network. Load shedding in Victoria ensued, and scarcity pricing ($10,000 per MWh) was triggered. During restoration of the system the scarcity price applied, despite generators being constrained down because there was insufficient demand to accept the generation. This led to generators not being able to back their contracted loads, resulting in significant commercial losses.

23 July 2008

Failure of two of the three circuits between the Loy Yang complex (Loy Yang A and B power stations, and the Basslink interconnection) and the Hazelwood terminal station caused offloading of Loy Yang A and Loy Yang B plant and high energy prices.

While the energy prices quickly recovered, the potential loss of the remaining 2200 MW of Loy Yang capacity from failure of the third line forced the System operator to increase the amount of Frequency Control Ancillary Services (FCAS) resulting in FCAS prices increasing to scarcity levels. Because the costs of FCAS services of this type are assigned to generators, IPRA's assets (and all other generators) faced effective marginal costs that were not covered by energy payments available in the market. The costs to IPRA were significant, with Loy Yang B unable to offer FCAS to offset the loss (the usual response) because it was behind the offending constraint.

These two events both left IPRA assets in positions of extreme and unmanageable financial exposure resulting from events they had no control over[3].

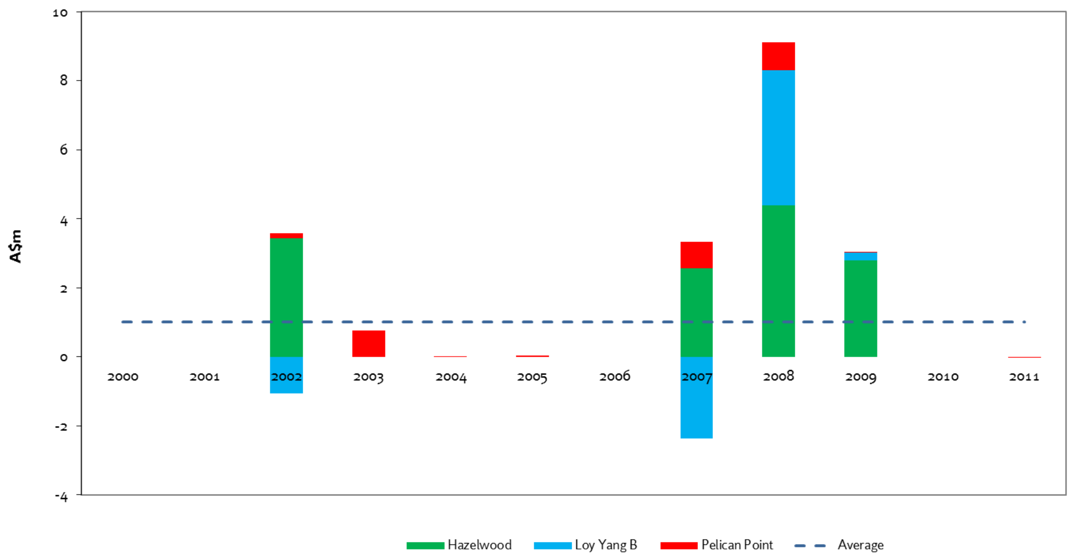
Figure 5 shows the cost of constraints over the last eleven years to IPRA. This chart was produced by internal IPRA analysis and examines the net impact on spot market revenue and contingency FCAS costs for IPRA plant following major transmission events[4].

A significant source of the cost of constraints during significant transmission events arise out of the allocation of raise FCAS costs. These are allocated on an energy-weighted basis to generators.

[3] Incidentally, repair work on one of the lines was not managed round-the-clock, a telling comment on incentives on TNSPs vis-a-vis the risk allocation to generators.

[4] The test to identify major transmission events was to examine events where a threshold level of total daily contingency FCAS costs in Victoria and South Australia was exceeded.

Figure 5: Net cost of transmission constraints to IPRA <u>from</u> <u>significant</u> <u>events</u>



Hazelwood and Loy Yang B supply around 30-50% of Victoria's energy requirement at any given time, and can therefore be exposed to that proportion of raise FCAS costs.

Pelican Point overnight can at times provide approximately 35% of South Australia's energy and faces a similar problem.

There is no conventional market or forward trading mechanisms exist which allow a participant to 'hedge' against FCAS costs. The only conventional mechanism which may provide some protection is to register to provide FCAS and receive revenue during these events to offset the costs.

The costs of transmission constraints from significant events are highly volatile. While these events are impossible to forecast, history has shown that they have been a persistent risk to operating in the NEM. Generators have limited or no ability to manage these costs. This risk is currently volatile and unmanageable.

The fact that average losses due to major events is circa A$1 million per annum is significant in its own right, but the within-year volatility is material and it should be possible for generators to ensure this risk is managed. Note that on some occasions there is a benefit. This is of little comfort, since is reflects volatility of revenue notwithstanding.

Finally, the AEMC is reminded that this analysis pertains only to significant transmission events. The ongoing cost of constraint due to being built out, system normal and contingent transmission outages is not included.

5 Desirable features of a transmission framework

In the first interim report, the AEMC specified the following set of desirable features for a transmission framework such that the National Electricity Objective will be supported:

a) *TNSPs have incentives to efficiently invest in and operate their networks to meet load requirements at least cost and support a competitive generation sector;*

b) *generators have incentives to offer their energy at an efficient price and invest in new plant where and when it is efficient to do so;*

c) *the policies, incentives and signals that govern transmission and generation decisions are coordinated to promote consistent decision making between the regulated and competitive sectors of the NEM; and*

d) *safety, reliability and security of the transmission system is maintained.*

IPRA is generally supportive of this approach, and agrees with the features as specified. However, we are concerned that this approach is incomplete without recognition of the history of NEM development and the treatment of existing investments.

We propose an additional feature that new transmission frameworks should include and then examine the justification for this. The additional feature is:

e) *Once connected to the network, generators should not be adversely impacted by changes to the market frameworks. Specifically generators in existence at the time that new transmission frameworks commence should not be disadvantaged by changes to their level of access or costs.*

The justification for this feature lies directly in the National Electricity Objective. The market relies on private investment in generation to maintain a continuing reliable supply of electricity. A major source of new investment in the NEM can be expected to be incumbents, who will be heavily influenced by their expectation of the impact of any future regulatory risks. This judgement will be primarily based on past regulatory outcomes. This applies to both project investors and the financial institutions providing investment funds.

The imposition of unmanageable regulatory risk will clearly raise concerns for all classes of potential future investors, at best leading to greater risk margins, or at worst diverting capital into other markets with less perceived regulatory risk. The electricity sector competes for investment funds with other sectors both domestically and internationally. With the financial crisis in the EU and the spectre of a second global financial crisis, investors are far more risk-averse and funding is more challenging to secure.

We acknowledge, but disagree with, concerns that the features sought in the interim report cannot be achieved without disadvantage to incumbents. We address this concern in our submission by describing in detail new transmission frameworks which provide all the features now proposed by the AEMC and also include our additional feature (e) covering existing generators.

We also note that there may be objections that this additional feature would constitute "unfair" treatment of some groups of generators (under the apparent AEMC perception of the open access arrangement). Our response to this is in three parts:

- firstly, we note that our additional feature involves <u>uniform treatment of all generators</u> in the important sense that all generators get the outcomes expected either when they made an investment decision to connect to the grid or on commencement of the market. Today's new entrant is tomorrow's incumbent;

- secondly, the National Electricity Objective calls for economic efficiency, not for fairness (a subjective quality in any event). We also believe that fairness is desirable, but only if it does not compromise economic efficiency. Whilst prospective generators are able to make their locational decisions in response to current regulatory frameworks, existing generators cannot alter their decision. Disadvantaging incumbent generators (by imposing new costs and/or restricting their access level) would be seen by prospective new entrants as an additional regulatory risk. This would lead to higher project costs, compromising economic efficiency, therefore failing the test of consistency with the NEO; and
- thirdly, consider whether achieving a perceived equal treatment in transmission frameworks would support more effective market competition. In relation to this we note that existing generators have been progressively connected to the grid over a period spanning several decades. Over this period many issues related to competition between generators have changed greatly. These include generation technology, the availability and cost of fuels, environmental regulations and objectives, the operational and maintenance demands of plant. We conclude that in the face of these many differences, an attempt at perceived equitable treatment focussing only on transmission arrangements will create risks for incumbents and will not promote effectiveness of competition in the market.

We further note that even if we confine our attention to transmission costs, it is now unlikely that the extent to which individual generators have already indirectly paid for network access can be accurately assessed, whether through a privatisation process prior to the NEM, or though debt allocation in the process of disaggregation of earlier state-owned bodies.

In short, we consider that while it is desirable to seek fairness as a notion within each age-group of generators, this must not be at the expense of economic efficiency, and we do not believe that there is any benefit in relation to the NEO in seeking fairness across plant of widely different vintages. Finally, the historical information that would be required for any realistic effort to achieve fairness in retrospective transmission charging is unlikely to be available.

6 Why each of the 5 options fails to satisfy the proposed features

6.1 Option 1 – "Open Access"

This option is described as having changes from the current arrangements only in relation to clause 5.4A of the Rules.

The current arrangements can be described as open access in the sense of being non-discriminatory[5], but this is not their essential characteristic. The specific characteristics of the current arrangements are that they are:

- informal, in the sense that critical elements of the arrangements are determined by TNSP practices rather than by the Rules of the market; and
- insecure and risky, in that access agreed between one generator and a TNSP can be degraded by the subsequent entry of another generator.

We note in particular that these informal arrangements are contrary to the clear intentions in clauses 5.3 and 5.4A of the Rules, while recognising that the current drafting of the Rules appears to fail in turning these intentions into obligations.

The open access option is in essence a do-nothing option. As a result there are no improvements in any of the four desirable features nominated by the AEMC.

Doing nothing might be considered by some to be a low risk approach. However the policy objectives to lower CO_2 emissions and move to cleaner energy is driving generation investment towards low carbon fuels, renewable generation, more distributed generation. New generation hubs will result as a consequence. These trends will place additional and new demands on the planning, connection and congestion arrangements in the NEM, which if not overcome, will impose barriers to entry for these important new entrants.

Objective	Alignment
TNSPs incentivised to efficiently support load and generation sector	Poor in relation to generators – TNSPs incentives to invest in relation to generator access are unrelated to the needs of generators
Generators offer and invest efficiently	Poor – generators do not have a satisfactory basis for investment in transmission access. In relation to offers there is a strong incentive for inefficient offers whenever congestion applies
Consistent decision making across regulated and competitive sectors	Poor – generators do not see the appropriate costs of locational decisions, nor the appropriate operational consequences of investment in the network
Safe, reliable and secure transmission system	Generally satisfactory, but incentives to achieve greater production through insecure outcomes in the case of congestion
No new regulatory risk on incumbent generators	The failure to protect agreed access in a significant regulatory risk to all generators, including current incumbents

[5] We contend that any access arrangements consistent with the NEO must be open in this sense, meaning that (a) there is no power of veto over entry, (b) there is protection against arbitrary charges, and (c) there is protection against arbitrary limitations on the use of access.

6.2 Option 2 - Open Access with Congestion Pricing

IPRA favours the introduction of a congestion management regime similar to the proposed Shared Access Congestion Pricing (SACP) mechanism to ensure efficient generator offers when impacted by network constraints. IPRA would also encourage that the SACP mechanism be extended to include the impact of Scheduled Network Service Provider bidding.

Although IPRA favours the SACP initiative, this on its own will not achieve the majority of the stated desirable outcomes.

Objective	Alignment
TNSPs incentivised to efficiently support load and generation sector	Poor. SACP does not impact on TNSP incentives for transmission planning or investment
Generators offer and invest efficiently	Improves incentives for efficient generator offers, but provides no incentives for efficient investment
Consistent decision making across regulated and competitive sectors	No change to current regulated planning arrangements. Although congestion pricing provides information on the cost of congestion, there are no incentives for this to be used to improve consistency across sectors
Safe, reliable and secure transmission system	Positive: reduces incentive on generators to achieve greater production through insecure outcomes
No new regulatory risk on incumbent generators	Access remains unprotected

6.3 Option 3 - Generator Reliability Standards

This option does introduce some measures to improve generator access and locational signals, but fails to provide the generator with the ability to customise the level of access to suit their business needs. A mandatory standard established by an independent body applied jurisdictionally is likely to be of very limited value to generators.

The assessment of this option against the specific desirable features is outlined below.

Objective	Alignment
TNSPs incentivised to efficiently support load and generation sector	Since the standard would be set by an independent body, and then applied differently within each jurisdiction, the likelihood that it will be valuable to individual generators is questionable. The party in the best position to determine what network changes are of value to its business is the generator itself Although TNSP payments and penalties are contemplated to incentivise their behaviour, since neither the standard itself nor the incentive arrangements directly involve the party most impacted (the generator), their effectiveness is low
Generators offer and invest efficiently	No change to congestion management therefore no change to generator offer incentives New generators may be influenced by the generator reliability standard regarding their investment decisions. However smearing the costs dilutes effectiveness of the signal

Consistent decision making across regulated and competitive sectors	Better alignment achieved through use of the TNSP standard. However as the Standard determination does not specifically involve the connected parties, the connection from regulated to competitive sectors is weak
Safe, reliable and secure transmission system	Not likely to impact on day to day operation of the network
No new regulatory risk on incumbent generators	Imposes new costs and restrictions on incumbent generators. Imposing location signals on incumbent generators is not efficient, as they are not in a position to respond Standards set independently of individual generators are less likely to be valued by the generators

6.4 Option 4 - Regional Optional Firm Access

This proposal seeks to provide a degree of financial firmness of access and also provide incentives for cost-based offers rather than (the pejoratively dubbed) disorderly bidding in the case of congestion.

However, the method chosen would create major uncertainties for generators which they would have no means of managing.

The method relies for its effect on payments from non-firm generators to firm generators. These payments may be limited by either a defined limit to liability applying to the non-firm generators, or alternatively by a defined limit to the right to compensation of the firm generators.

It is therefore evident that for a particular constraint and a particular configuration of available generators at the time:

- if the relevant generators are all non-firm then the payments will be zero, with the result that incentives for disorderly bidding will apply with the same force as they do now; or
- if the relevant generators are all firm then the payments will be zero, with the result that incentives for disorderly bidding will apply with the same force as they do now, and no added firmness will be achieved.

Between these extreme cases there may be some incentives against disorderly bidding, and some degree of firmness, but it would be extremely difficult for a generator to evaluate for a particular case of congestion with a particular set of generators availabilities and offers, what incentive applies (after the event this will be discoverable, though no longer useful).

For this reason the risks introduced by this method are not manageable by generators.

It should also be noted that this method also introduces a dynamic instability. Consider a group of generators facing (for simplicity) one constraint that affects them all. The best outcome for every generator is for them all to be non-firm, as that will minimise their costs.

The worst outcome is for them all to become firm, as they will thereby all incur substantial costs, and will have the same network access as they would have had if all were non-firm. However, the best outcome is unstable as one generator may get a temporary advantage by becoming firm, thus potentially leading to a stampede toward the worst outcome.

Although this option introduces the concept of choice of access level, its effectiveness and efficiency are diminished by:

- not involving the generator in the negotiation of the standard;
- mandating a one size fits all standard (risks sacrificing commercial and economic efficiency); and
- attempting to combine congestion management and firm access compensation, with the result that neither is managed well.

The assessment of this option against the specific desirable features is outlined below.

Objective	Alignment
TNSPs incentivised to efficiently support load and generation sector	Since the standard would be set by an independent body, and then applied differently within each jurisdiction, the likelihood that it will be valuable to individual generators is questionable. The party in the best position to determine what network changes are of value to its business is the generator itself Although TNSP payments and penalties are contemplated to incentivise their behaviour, since neither the standard itself nor the incentive arrangements directly involve the party most impacted (the generator), their effectiveness is diminished
Generators offer and invest efficiently	The incentives for efficient generator offers would vary from zero to some higher level, but would be extremely difficult to evaluate when decisions on offers need to be made Network capability varies considerably with system conditions. Even if all generators at a node are ‘firm’ (due to the view that the network capacity can normally cater for them all), at dispatch time they could be constrained, but there are no non-firm gens to pay compensation
Consistent decision making across regulated and competitive sectors	Better alignment achieved through use of the TNSP standard. However as the Standard determination does not specifically involve the connected parties, the connection from regulated to competitive sectors is weak
Safe, reliable and secure transmission system	May improve reliability through increased access for generators to RRN. Unlikely to impact on security
No new regulatory risk on incumbent generators	Poor. Incumbent private generators previously purchased with understanding that network access applied would be required to pay for firm network capability, or be exposed to potential compensation payments. These costs were not anticipated at time of sale

6.5 Option 5 - National Locational Marginal Pricing

This option is in fact two independent changes rolled together. These are:

- arrangements to allow firm financial access to a reference node (for some generators – see later). This arrangement could be applied equally well within a regional market as in a single national market; and

- a change to a single national market with only one reference node. This could be applied with other access arrangements, although it clearly makes access arrangements more critical than they are in a regional market.

Our major concern with this composite option relates to a critical limitation of the firm financial access regime proposed. This limitation is that a generator with firm access would receive the firming payment only if it would have been dispatched in an unconstrained system. There will generally be generation dispatched in the constrained situation that would not have been dispatched in an unconstrained situation, in order to replace the generation prevented by the congestion.

This is a crucial limitation. It might be considered, if regard is given to the spot market only, that a generator in this position would be adequately rewarded by the local price which must equal or exceed that generator's offer price.

But this view ignores the effect of hedging contracts. If a generator in this position were party to hedging contracts then it would suffer through making difference payments based on the reference node price while receiving only the local price.

Thus this proposal would apply severe penalties on blameless generators who were hedged, but happened to be in the wrong place in the dispatch order. This would inevitably reduce the appetite for generators to enter hedging contracts with customers.

Given the importance of hedging to both generators and customers in the market, we contend that this option should be excluded from further consideration based on this critical limitation alone.

On this basis we will not comment further on the potential alignment with the set of desirable features.

7 Integrated package of framework elements

This section of our submission describes an integrated package of complementary measures that we propose as major components of a new transmission framework. We will later demonstrate that this package delivers all the features that the Commission has set out as desirable as well as meeting the additional feature that we have proposed above.

We will also later show the connections between some of these measures and evident, but unrealised, intentions within the current Rules.

We will begin by listing these measures, and will then examine each in some detail:

a) protection of agreed access;

b) locational signals through charging deep connection costs for new entrants;

c) choice of level of access;

d) ability to trade access;

e) congestion management; and

f) interconnector planning to maintain a sufficiently integrated NEM.

7.1 Protection of agreed access

The intention that agreed access should be protected from degradation due to subsequent generator entry is evident in the current Rules. Our proposal in this regard is that the future frameworks should ensure that this intention is realised, rather than remove clauses that attempt to reflect this intent because they are inconvenient or unworkable in their current form.

Maintaining this original intent that there should be some protection of agreed access is proposed for two reasons:

- if access is unprotected in the sense that the access of one participant, as agreed with the TNSP, can be degraded by the action of a third party, then this must adversely impact on potential investors in a way that is contrary to the NEO. The potential investor will either be discouraged or will seek a greater risk margin on this account; and
- if, as we separately propose, new entrants face a locational signal in the form of a cost of access (which is consistent with the NEO), then they will not be justified in paying for an efficient level of access if that access is not protected.

In seeking a form of protection of agreed access, we need to be clear on the form of protection proposed. The actual level of access that a group of nearby generators share can be envisaged as the combination of:

- a base level of access which applies when the network is in a defined state (in terms of availability of network assets, temperature, wind speed, voltage levels and other relevant circumstances); and
- frequent and sometimes large fluctuations away from this base level. Most of these fluctuations will give lower access (although as discussed later, to some extent this depends on how the base level is defined).

The proposal we are advocating is a planning process to ensure that the base level of access, under certain defined conditions, is sufficient to simultaneously provide all the agreed individual levels of access to all relevant generators.

This proposal leaves generators still facing the remaining fluctuations in network access as system circumstances change. While protection from, or compensation for, such fluctuations would clearly be desirable from the perspective of generators, it is not part of the proposal advocated here for reasons given earlier.

The first part of implementing this proposal would be a requirement in the Rules that a Network Service Provider must not agree to any additional access unless and until it has demonstrated by a planning study that it can provide this new access in parallel with all previously agreed access (but would remain obliged to do whatever is necessary to provide the access sought). This may or may not require network augmentation, depending on circumstances.

The second part of implementation would be defining a set of principles to be adopted in the above evaluation, what might be called a measurement protocol. Some considerations in relation to such a measurement protocol are contained in section 9.3 of this submission.

7.2 Locational signal for new generators

We propose that the transmission frameworks should include effective and complete locational signals related to transmission as applicable for new generators.

This is necessary to ensure that decentralised decisions by prospective generators result in overall efficient investment across both their own investment in plant and the consequential investments in the transmission network.

We have emphasised “effective and complete” locational signals because we recognise that some aspects of the current market arrangements provide limited locational signals, but also that one important aspect has not been implemented. This is the cost of providing access in terms of maintaining the adequacy of the shared network capability (by augmentation of the network as necessary). The cost of maintaining network capability, relative to access granted, is appropriate because if capability is not so maintained then the cost of one generators entry can be imposed largely on other generators, leading to inefficient investment decisions.

It is also relevant to note here that one of the existing locational signals, namely the application of marginal loss factors in market settlement is, largely for technical reasons, inflated to about twice its physical value. This practice has applied since market start and serves contrasting purposes as both a factor in efficient dispatch and as a locational signal. We recommend that the Commission should, in parallel with filling the gap to make locational signals more effective and complete, also seek a way to counteract this existing inefficient over-signalling of losses as a locational signal. We note that there is an inconsistency which needs to be resolved, between the requirement for efficient dispatch , requiring marginal loss factors, and the requirements for efficient locational signalling, requiring average loss factors.

This over-signalling has very different locational characteristics from the costs of network augmentation, and hence these two issues of network costs and network losses should not be regarded as trading off one against the other.

A critical characteristic of locational signals for generators is that they can only be effective to the extent that they are known in quantitative terms when the locational decision is made. It is generally impractical (technically and commercially) to re-locate a generator once constructed, so retrospectively applied or altered incentives will have no benefit as a locational signal. The issue of retirement incentives is better handled by other means – see later (Section 7.4).

In this regard, the cost of any network augmentation that is needed to provide access would form an efficient and practical locational signal, since the lifetime cost of network assets is quite well defined at the time of construction.

In contrast, the existing locational signals of congestion and loss factors are extremely difficult for a prospective generator to forecast over the life of their plant, and hence are inherently less efficient. We nevertheless support their continued application, subject to the changes proposed in this submission (which will provide a more predictable level of congestion, and eliminate the over-signalling of the current marginal loss factor practice). Our support is on the basis that these are better included, however imperfectly, rather than hidden.

While supporting the application of charges in relation to any necessary network augmentation in order to complete the locational signals, we recognise that the important issue of economies of scale in network construction will complicate the application of this principle. We note however that this issue is not unique to our proposal, but is an important issue in relation to any process of charging for transmission services, even if it is not made explicit.

We will discuss later in this submission a specific proposal to deal with this aspect. We will also discuss the perceived difficulties in basing charges on deep connection costs, and explain why these difficulties do not arise under our proposal.

We note that this element of our proposal conforms with our proposed additional item (e) to the list of desirable features, in that it does not disadvantage existing generators relative to their reasonable expectations when they entered the market.

We also note the intimate connection between this element and the previous one, in that charging generators for the cost of their network access as proposed provides an efficient incentive because there is an identifiable and durable benefit associated with that charge.

7.3 Choice of level of access

The level of access for a generator need not match the capacity of the plant. While we expect that all generators will want connection equipment that matches the capability of the generation plant, there are different incentives in relation to the capacity of the shared network to allow access. For this, a generator may rationally choose a lower access level, where that generator foresees little conflict between their needs and the needs of other nearby generators, for example, in cases where the purpose of the new generator is to firm up or backup existing plant.

We also note that a generator could correspondingly seek access greater than its plant capacity in order to give a high level of assurance of reliable access or to cater for future plant expansion. Our proposal would allow this if desired and in this case, the network would be upgraded as necessary to achieve this greater level of access.

The proposal to allow a choice of access level relates to the previous two elements of this proposal, namely protection of access and cost of access.

The chosen level of access would be the level protected during entry of subsequent new generators. It would also be the basis for determining any network augmentation needed to support access, and hence determine the magnitude of that locational signal.

In order that a choice of the level of access should lead to efficiency gains, the participant making the choice should be subject as far as possible to the genuine consequences of that choice.

The first relevant consequence, as mentioned above, is that the participant would face network charges that relate directly to the choice made.

The second form of appropriate consequence is that the operational consequences should directly relate to this chosen level. Thus a chosen low level of network access should lead to more restrictive operational consequences than a higher level of access. But, on the other hand, in order to maximise market efficiency, these operational consequences should not result in under-utilisation of the network.

The proposal below satisfies all these conditions.

Before setting out the detail, it is convenient to discuss the means by which these operational consequences would be imposed. The context within which the arrangements will operate influences the form they should take. We note that a partial access level would need to be agreed between a prospective generator and the Network Service Provider. The quantity would appear in the bilateral connection agreement between these parties. It is therefore convenient and pragmatic to keep the operational consequences within this agreement. This has the advantage that market dispatch and settlement processes do not need any alteration and, by avoiding any need to keep a third party informed of agreed access level, the risk of error is reduced.

The proposal is that the Rules would be changed to require that a Network Service Provider that agrees to provide a level of access to a generator which is less than the plant capacity must include certain specific conditions in that agreement. For convenience we will refer to such access as partial access.

The requirements that the connection agreement would impose on the generator with partial access are as follows:

- the generator with partial access is free to offer to the market as it chooses except when there is a relevant binding network constraint (this is to avoid needless restrictions on network utilisation);
- when there is a relevant binding network constraint the generator with partial access must not offer greater generator availability to the market than its agreed partial access level; and

- in the event that a generator with partial access fails to comply with the above condition, then it owes the Network Service Provider compensation equal to the additional revenue received due to non-compliance.

The term “relevant binding network constraint” used above refers to a constraint equation applied in dispatch and representing a network limit in which the output of the relevant generator appears explicitly as a dispatch quantity.

A further aspect of this proposal is that the Network Service Provider, if it becomes entitled to such compensation, would be obliged to use the whole amount to compensate those other generators that are determined to have been adversely affected by the non-compliance. This compensation would be required to be in proportion to those losses of revenue due to that non-compliance.

We understand that such a mechanism is quite similar to the intentions of the original NEM Code as contemplated by its designers, although these intentions are not clearly evident in the current drafting in clause 5.4A.

The obligation to avoid the incidence of a relevant binding constraint or to limit their offer, allows the generator to make use of network capability to provide more than their agreed access at times, but on the other hand imposes an obligation to monitor the possibility of congestion and act in a timely manner when that risk is imminent. The rewards of greater access (above the agreed level) are balanced by the need for prudent and timely action to meet their obligation.

We note that while this proposal includes the possibility of compensation paid by one generator and received by others, it is not the intention that such compensation would normally apply. Rather the compensation mechanism has the intention of ensuring compliance with the obligation to restrict offered availability to avoid or reduce network congestion. If this obligation is met then no compensation would be paid or received.

It might be thought that a restriction on generation availability offered to the market would adversely affect supply reliability. However it should be noted that the circumstances in which an availability offer would be reduced are circumstances where all the offered availability would not genuinely add to reliability because it would be restricted in dispatch due to the congestion.

This component of our integrated package is logically connected to those previously described. If a prospective generator is required to pay for the network augmentation needed to allow ongoing access, then it should have a choice in the level provided and hence the cost to be met and should also face the operational consequences consistent with that choice.

7.4 Ability to trade access

The proposal described above allows a prospective generator to choose the level of network access that suits its particular purposes. However over the life of a generating plant, the needs for access may change.

The case of a generator seeking a greater level of access is straightforward; the generator would negotiate with the Network Service Provider for a higher level of access and this process would resolve any changes to costs and the associated operational benefits.

The contrary case is more difficult, since the cost of initially providing access will often be the construction of expensive and long-life assets, and there would naturally be a risk that a reduction in access provided would leave a stranded asset. It would be inappropriate to allow a generator reduced charges for reduced access if there were no reduction in network costs and no alternative source of funds. However reduced charges could apply if there were another generator willing to buy a part (or all) of the existing access provision. We propose that the Rules should provide for such transactions, with particular conditions.

We note that network access is location-specific and hence that a purchaser of existing access should be responsible for any plant or arrangements needed to get their output to the location of the existing access.

The purchaser would take on a proportion of the existing agreed access and the same proportion of any ongoing costs associated with that access.

The Network Service Provider would need to be satisfied that the purchaser's plant met technical requirements, and that the purchaser was credit-worthy in relation to any ongoing charges.

Such a transaction may leave the seller or the buyer (or both) holding partial access for their plant, and we envisage the provisions described above for partial access would be applied where relevant.

The proposal to allow trade of access has particular relevance where plant retirement is contemplated. In this case there may be a number of advantages for new plant locating where plant is retiring. In addition to the use of existing network access, there may be other benefits including fuel supply or transport arrangements, cooling water facilities and skilled local workforce.

We submit that providing for trade in network access would best allow these commercial issues to be balanced without an intrusion from a central planning model. Any central planning model would be unable to determine a market value for the existing access, and would provide only a more or less arbitrary charge based on historical costs.

This proposal is logically linked to our proposal for protection of agreed access, because without such protection there would be nothing durable to trade.

The negotiation of the terms of such a trade would provide an alternative locational signal that could then be compared to the costs of potential entry at other locations.

The ability to trade a quantity of access that is suitable to a prospective buyer is dependent on having arrangements for partial access, such as those described above.

7.5 Congestion management

We propose the implementation of a congestion management regime, of the type that we have earlier described to the Commission and which formed the basis for the SACP proposal in the first interim report.

We will not repeat here the details of that proposal, but will briefly summarise the reasons for its inclusion in our package, covering the circumstances that support its inclusion and the expected outcomes from it.

The capability of the transmission network, particularly in the Australian context, is subject to frequent and sometimes large changes. Partly as a result of this, augmenting the network to reduce the incidence of congestion is subject to diminishing returns, and hence it is not regarded as practicable to reduce network congestion to negligible levels.

In addition, because of its geographical extent, the network is subject to a variety of environmental risks which can cause major disruption. These risks include bush fires, severe storms, floods, earthquakes, landslides, among others. Hence the possibility of large scale congestion with little warning is always present.

Under the current arrangements, when congestion occurs, participants behind the constraint are frequently incentivised to make offers at the lowest price allowed ($-1000 per MWh). This results in inefficient dispatch of those generators subject to the congestion, and leads to market behaviours and market outcomes which are difficult to explain or justify to those unfamiliar with the current dispatch and pricing arrangements.

The incentive for this action, (pejoratively dubbed "disorderly bidding"), can be eliminated by changes to the market settlement process to provide effective price signals to alter behaviours. These need to retain a substantial settlement quantity at the Regional Reference Price, in order to support hedging contracts, while at the same time giving incentives at the margin for generation variations which reflect the local price determined by the dispatch process.

This could, at least in theory, be done on local and time-limited way to deal with substantial congestion as it arises. However, application in this form would be expensive, and given the great unpredictability of congestion would generally be lagging (i.e. behind the action).

The alternative which we have proposed is to institute a standard process which is triggered by the actual incidence of congestion and hence provides a proportionate and timely response as circumstances change.

This proposal has previously been described to the Commission and here we will only briefly describe its effects:

- it eliminates the incentive for 'disorderly bidding';
- as a consequence it allows improved dispatch efficiency in the event of congestion, with the benefits shared between the affected generators;
- by eliminating 'disorderly bidding' it allows the dispatch process to schedule counter-price interconnector flows if and only if these are economic;
- in the event of economic counter-price interconnector flows, the changed settlement process leads to a positive settlement residue for the interconnector;
- this positive settlement residue eliminates the need for the market operator to limit economic counter-price flows; and
- the positive settlement residue arising from a counter-price flow enhances the value of settlement residue auction units in the management of inter-regional basis risk.

This proposal is complementary to other parts of our proposed package in relation to time scale. This congestion management regime has its effects in the operational time frame when the change in incentives to discourage 'disorderly bidding' must apply. On the other hand our proposals on protection of access, locational signals and choice of level of access all have their effect at the time that a locational decision needs to be made.

The congestion management proposal also complements another aspect of our package, to be described below, intended to increase the certainty of interconnector capability. That aspect seeks to increase the certainty of interconnector physical capability, while this aspect, namely congestion management, seeks, *inter alia*, to increase the inter-regional risk management support that derives from a given physical capability.

A further complementarity exists in that our proposals in relation to generator access are designed to allow choice by generators of their level of access. It is not possible to say in advance whether this exercise of choice, if implemented, would result in more or less congestion. In this context, the implementation of congestion management in advance, to deal with whatever level of congestion does emerge should be seen as a prudent and low-cost precaution.

Congestion management would provide various efficiency improvements in the operational time frame, complementing the larger-scale measures that form the remainder of the package.

7.6 Interconnector planning to maintain a sufficiently integrated NEM

IPRA proposes that there should be a change in the network planning arrangements with the intention that sufficient interconnection capacity should be maintained to ensure that the NEM functions broadly as described, rather than as a series of separate markets.

We note that in the context of a Rule change proposal on potential generator market power the Commission has contemplated the possibility of classifying a market region as a separate market for the purpose of assessing market power issues. That this outcome is seen as a serious possibility causes us concern, as it suggests to us that interconnector performance may have fallen below some critical level that is needed to ensure that the NEM can be described as a truly “national” market, rather than as a series of loosely interconnected markets.

Further, we have provided the Commission with evidence earlier in this submission that in particular instances the average capability of interconnection has declined over time, and separately that interconnection capability has exhibited extreme short-term volatility. These outcomes raise concerns in relation to whether interconnector capability has been sacrificed as a solution to local transmission issues, or at least reflect the pre-eminence of intra-regional investment mechanisms in the NEM over inter-regional investment mechanisms.

We note that there appears to be no defined responsibility for interconnector capacity or reliability under the current frameworks.

This proposal is less defined than other components of our package because we recognise that there are likely to be alternative methods which would achieve our aim, and we can at present see no convincing reason to prefer one over another. Furthermore the method adopted should be matched to whatever transmission planning regime is recommended by this review.

Accordingly we will confine our recommendation to broad aims. These are:

- there should be a single body responsible for determining for every regulated interconnector, the necessary capacity and reliability for delivery of that capacity for each flow direction and each year, for a substantial planning period (say 5 years);
- the bodies responsible for transmission planning locally should be obliged to determine and implement the most economic means to deliver that performance; and
- in the same way as new connection should not be permitted to undermine the level of access available to other participants, so new connections or network augmentations should not be permitted to reduce interconnection capability.

The last of these aims is consistent with our reasoning in the preceding sections. Investment certainty for participants is not restricted to certainty that access to the regional reference node is maintained. Locational decisions also involve consideration of the dynamics and potential of the market as it operates in adjacent regions, and the likely risks arising from changes (positive or negative) in the capability of interconnection to support access to and from these regions.

In proposing this change we are not seeking to make the case that adequate interconnector capability cannot be delivered by the current framework. Rather we are suggesting that the current framework gives insufficient assurance that adequate interconnector performance will be provided and that greater assurance would be consistent with the NEO.

The assurance of interconnector capability is likely to become more important over time, as the distribution of low CO_2 emitting energy resources may lead to increasing departures from the approximate regional supply-demand balance that applied early in the market. In these circumstances the assurance of future interconnector capability would be increasingly important in generation investment decisions.

8 Alignment of proposal with desirable features

IPRA has noted earlier in this submission our support for the list of features proposed in the first interim report. We have also proposed an additional feature to further enhance the contribution of the transmission frameworks to the National Electricity Objective. In this section we will examine the alignment between our proposal as described above, and this set of desirable features.

8.1 TNSP incentives for investment and operation

Our proposal provides for efficient investment in networks and allows enhanced incentives for efficient operation.

In relation to network investment to support generator access, the proposal ensures that a connecting generator faces both the costs and the benefits of any network investment to support its access. The generator is enabled to commit to such costs because the agreed access will be protected. The choice of level of access allows the generator to gain the network access that suits its individual needs. We contend that individual choices driven by commercial disciplines will lead to more economically efficient outcomes than any central planning model can achieve.

In relation to network investment to support interconnector flows, our proposal provides greater efficiency by separating the decision on the level of interconnection needed from the optimisation of the cost of providing that level. TNSPs are not well placed to evaluate competition benefits from increased interconnector capability. Furthermore, a TNSP seeking to increase interconnector capability by changes within its network may be frustrated by the absence of complementary changes in the neighbouring network. Hence we contend that NEM-wide analysis should be the basis for decisions on interconnector capability.

In relation to efficient operation of the network, we note that currently the efforts by the Australian Energy Regulator (AER) to incentivise efficient network operation are limited in their effectiveness because 'disorderly bidding' obscures the cost of network congestion. The congestion management component of our integrated package will eliminate the incentive for 'disorderly bidding', and hence enable a more effective incentive arrangement to be developed and implemented.

8.2 Generator incentives

The incentives for efficient investment in new generation plant are improved by several of the components of our integrated package. These are:

- protection of agreed access;
- locational signals through charging deep connection costs for new entrant generators;
- choice of level of access; and
- ability to trade access.

These allow the generator to make the appropriate trade-offs, from their perspective, between the locational costs associated with the transmission network and the various other costs that are affected by a locational decision.

In relation to generators offering energy at an efficient price, we note that the congestion management component of our integrated package will eliminate the incentives for 'disorderly bidding', which is now the major component of inefficient pricing.

8.3 Coordination between transmission and generation

IPRA agrees that the policies, incentives and signals that govern transmission and generation decisions should be coordinated to promote consistent decision making. Our proposal supports such coordination in the following ways:

- the protection of agreed access gives generators sufficient basis to commit to pay for access where this forms part of their optimal locational choice;
- the right of a TNSP to charge for deep connection costs gives it a firm basis for investment in any augmentation needed to provide a chosen level of access;
- the choice of a level of access allows a coordinated approach to the planning of generation and any network augmentation needed to provide that level of access; and
- our proposal for interconnector capacity planning allows the required network service to ensure adequate inter-regional competition to be determined independently, while maintaining the responsibility of the TNSP to serve this requirement in the most economical way.

8.4 Safety, reliability and security of system maintained

Our proposal is fully consistent with the maintenance of the safety, reliability and security of the transmission system at current levels, or better.

We note that under the existing arrangements when congestion occurs there have at times been efforts to maintain production levels, other than 'disorderly bidding', which have compromised system security. We expect that the implementation of the congestion management component of our package will substantially reduce the pressure to take such action, and hence will support security outcomes which are at times better than under the current arrangements.

8.5 Existing generators not disadvantaged

This additional feature, proposed by us, has been a guiding principle in the design of our package, and is a significant difference separating our proposal from the options considered in the first interim report.

The reasons for adopting this feature are outlined earlier in this submission.

The elements of our package that support this feature are as follows:

- existing generators are required to make only those payments for transmission services that they anticipated at the time of either connection or market start; and
- existing generators are not treated as having lesser access rights than generators that subsequently enter the market.

9 Clarification of issues raised by the integrated proposal

The integrated proposal for revised transmission frameworks described in section 7 above is different in a number of aspects from any of the options described in the first interim report.

This section of our submission will discuss these points of difference and outline our justification for choosing a different path.

9.1 The uncertainty of network limits

There is one single issue that underlies many of the differences between our approach and that of the first interim report, namely the recognition of the inherent uncertainty of network limits. The analysis that supports that report includes always the implicit assumption than the limits to network flow are stable and predictable.

We contend that all such analysis is essentially irrelevant to the actual market precisely because this assumption is seriously flawed. We further contend that any policy proposal arising from this analysis will generally not have the intended or expected effect because of this limitation in the analysis.

Our views on this matter are different because we have the opportunity to draw on years of actual operational experience in the NEM, and also on years of close involvement in the development and improvement of the dispatch and pricing mechanisms used in the NEM (through representation on the Dispatch and Pricing Reference Group which is an advisory group to AEMO).

In Appendix 3 we have included evidence in support of our views on the inherent uncertainty of network limits.

We are aware that broad-scale and extended aggregations of congestion statistics show reasonable stability. However, no participant has their market participation affected by wide geographical averages or by averages of these over a long period. Instead their commercial outcomes are influenced by the local and time specific events, i.e. by precisely that detail which is lost in broad-scale statistics.

There is one exception to our critique on this issue of the proposals in the first interim report; that is, the congestion management proposal (SACP) included in option 2. Because this draws heavily on a design developed by market participants, it is specifically designed to operate effectively in an environment where congestion cannot be effectively forecast.

Our recognition of the uncertainty of network limits has strongly influenced our integrated package that we have described above. For example we have carefully avoided any measure that would require valuation of local, short or medium term congestion (such as the auctioning of any form of rights). We believe that reliance on such valuations would lead to inefficient and volatile outcomes.

In contrast our package requires participants to take a view on future congestion only in relation to deciding the level of access that they should choose. This allows for a very long averaging period. Our proposal further supports this choice by providing that the access level, and hence a base level of congestion, must be protected. This significantly reduces the unmanageable risk that the generator must confront.

We have in addition included a measure to allow a generator to revise its level of access if experience in the market suggests it should. The ability to seek enhanced access is present through negotiation. We have proposed in addition the ability to trade access which is no longer required (where there is willing and qualified buyer).

In summary, we commend our package to the Commission on the basis that it gives careful recognition to the inherent uncertainty of network limits. We contend that any proposal not so constructed is likely to prove inefficient in practice.

9.2 Deep connection charges and economies of scale in transmission

We have chosen to discuss the two issues of deep connection charges and economies of scale in transmission together. This is partly because they are related, but also because the Commission's assessment of deep connection charges is apparently influenced by an assumption that economies of scale should be handled in a particular way.

In section 7.2 we have described locational signals as "the cost of any network augmentation that is needed to provide access", which implies deep connection charging, although we did not at that point use the term. This was in part because the meaning that we have chosen to attach to this term is somewhat different to that used by the Commission, and we have left it until this point to add the further detail to make this clear.

We are advocating deep connection charging for two main reasons:

- the alternative of a zonal charging regime would not deliver sufficient locational signal granularity to achieve efficient outcomes. Within any sizable zone there is likely be a node dominated by generation and another node dominated by consumption. A zonal charge would fail to distinguish between these nodes, despite the network costs of providing access being likely very different; and
- a zonal charging mechanism requires additional, complex and controversial analysis relative to deep connection charging. A large part of the information needed for deep connection charging is delivered automatically from the necessary network planning to support the agreement of access. In contrast, a zonal charging arrangement would require separate analysis and does not have any clear underlying principle, making the process controversial and open to legal challenge.

The potential for difficulties with deep connection charging arise, as the Commission has identified, from the possibility that the network augmentation constructed will not match the requirements for the generator access to be provided.

These mismatches arise from two main causes:

- Network Service Providers standardise their equipment to a substantial degree. They use only a limited range of voltages and may also choose to use a limited range of plant items including transformers and conductors. As a result assets will almost uniformly be sized up. The effects of this are common but will generally not be very large; and

- there are potentially significant economies of scale available by providing for possible, but uncertain, future demand for network services, during the process of providing for a current need. This applies not only to the network equipment itself, but also to related resources such as land and easements.

We submit that while the first cause may be regarded as part of the inherent cost structure facing market participants, the second is too material to be treated this way.

The issue of economies of scale is not only likely to be material in its effect; it is also inherently based on opinion, since it relates to potential but uncommitted developments in network utilisation. The distinction that we wish to draw is that generators should be faced with incentives based on the facts of the network, but not any that are based on opinions about the likely future development of the network.

On the other hand, we are not suggesting that potential economies of scale should be disregarded, just that a prospective generator is not equipped to manage the risks and rewards that apply.

We therefore propose a process whereby both the risks and the benefits of scale-efficient construction would be allocated to customers:

- where providing the desired level of access to a new entrant generators requires network augmentation, that generator should be charged the estimated stand-alone costs of meeting that requirement;
- the Network Service Provider, with the approval of the AER, may build a scale-efficient alternative (this should be without additional delay);
- any subsequent generator using that facility would also pay their own stand-alone cost (by using that facility we mean in the sense that had that augmentation not been constructed and the earlier user(s) were not present then network augmentation would have now been needed); and
- if the aggregate payments from generators did not meet the cost of the facility the customers would pay the difference, but if the aggregate payments from generators exceeded the actual cost, then the costs to customers would be reduced by the difference (noting that, with economies of scale, full cost recovery will occur with only partial usage of the facility).

This proposed process provides equitable treatment for the generators involved, regardless of whether they trigger a network augmentation or alternatively utilise an augmentation already constructed, and thus avoids creating queuing problems by eliminating any incentive for a generator to wait for a competitor to pay for network augmentation.

Under this proposal, customers would support the cost of scale-efficient design only when it was seriously under-utilised, and would effectively gain the scale benefit when the major part of the capacity was utilised.

In addition to the issue of scale-efficiency which is discussed above, the main issue regarding the application of deep connection charging is the difficulty of allocating costs to existing participants. We agree that such *ex-post* cost allocation would be difficult, and we contend that any ex-post cost allocation for transmission costs is essentially arbitrary. (We note in passing that such ex-post allocation seems unavoidable for the multitude of small customers, despite its arbitrary nature).

However, in the case of generators, and large customers, it not necessary to use *ex-post* pricing, as the relevant costs can be determined with good accuracy at the time that the network augmentation is decided.

Under our proposals there would be no retrospective charges (for reasons given elsewhere) and hence *ex-ante* cost determination is all that is required. Hence, this major objection to deep connection charging is not relevant under our integrated package.

Under our proposal, economies of scale are not dealt with by imposing a particular burden on any generator that triggers a network augmentation if a scale efficient design is adopted. Further, because we have proposed prospective charges only, another major objection to deep connection charging, namely problems of retrospective application, does not apply to our proposal.

In short, the perceived difficulties of applying deep connection costs as the price of generator access do not apply to our proposal, partly because it is not retrospective and partly because we would treat economies of scale differently.

9.3 The measurement protocol

We have proposed in our integrated package that the agreed access for a generator should be protected when considering whether or not network augmentation is required to allow further access to be agreed.

Given the wide ranging and frequent changes in capability that the transmission network often exhibits, this determination is not trivial. Also, given that many extrinsic and intrinsic circumstances can affect network capacity, the results of such analysis could be unreliable and subject to prejudice.

We therefore consider that it would be an essential component of our integrated package that this process should be standardised and well managed. The suggested approach would be to have a set of high level principles in the Rules, to be supported by a more detailed protocol, which could be developed, for example, by the AER in consultation with the industry.

This proposal for a measurement protocol has much in common with the proposal under option 3 in the first interim report, for a generator reliability standard.

There are however, some deliberate differences in detail between these:

- the output from a generator considered in the process would, under our proposal, not be the plant capability but rather the agreed level of access for existing generators or the level of access sought, for a proposed new entrant. This is required for consistency with the choice of level of access that applies under our package; and
- we propose that the measurement of access should relate to the network capability relative to the aggregate of access being considered (either already agreed or now sought), and not depend on any assumptions in relation to generator offer prices or dispatch outcomes.

The first point is related to the element of our package that relates to choice of level of access, which we have described and justified elsewhere.

The second point, namely testing for the capability to provide all potentially conflicting access simultaneously, has two aspects. Firstly, we take a different view on what the provision of access should mean. The proposal, in the first interim report, to use assumptions about dispatch in the analysis, indicates an intention that planned access would be provided, even under the test conditions, only under benign market conditions. In contrast we are proposing that the test of access should imply more stressful market conditions. When supply/demand balance in the market is disturbed by a distant event (such as multiple generator failures) then the local generators with potentially conflicting access needs will likely all be seeking access simultaneously. We propose that access should be defined with this more demanding situation in mind.

The second aspect of measuring access on our proposed basis is that it eliminates the need to make any assumption in the analysis regarding offer prices for generators and the resultant dispatch outcomes. We recommend against the use of these assumptions because there can be no firm basis for making these assumptions and hence they would unavoidably have a subjective component.

We appreciate that an assumption of simultaneous use of all agreed access NEM-wide would not be realistic, but this is not what we advocate. We envisage in each case the analysis being affectively confined to a part of the network within which generator access is potentially conflicting, with freedom to make compatible assumptions for the rest of the network. In other words, we consider the analysis should consider simultaneous access within each "chunk" of the network separately.

In summary, our proposal for the measurement of access allows for choice of access level, relates more closely to the real needs of generators, and also avoids the use of subjective assumptions.

Apart from these deliberate differences, we envisage that the measurement protocol that we are proposing would be similar to that which would be required under options 3, 4 or 5.

The issues we expect to be covered by the measurement protocol include:

- the condition of the network assumed in the analysis in terms of plant available;
- the ambient conditions affecting network plant, including temperature, wind speed and sunlight;
- the operating conditions of the network such as voltage, tap positions, reactive power sources and sinks; and
- the demand levels to be studied, noting that depending on circumstances, higher demand may increase or decrease the access that can be provided.

These issues will affect the access that is measured as being available from a given network configuration, and hence affect the base level of congestion that is experienced by generators with access.

9.4 No discrimination by market operator

It appears that under options 4 or 5 in the first interim report, the market settlement process would be altered to discriminate between firm and non-firm generation. Hence AEMO would be discriminating between generators on the basis of arrangement to which they would not be a party.

While we do not dispute that this would be possible, we have taken the view that it would be undesirable and introduce a needless opportunity for errors and dispute.

We have therefore chosen to confine the consequences of partial access under our proposal entirely to the two parties which would agree that partial access, namely the generator and the Network Service Provider.

Further, the proposed congestion management regime relies entirely on information now available to AEMO, and does not discriminate between generators that present equally to the market dispatch process.

Consequently, under our proposal there is no need for the market operator to discriminate between generators.

10 Costs of implementing this package

The package of measures described above has been examined in our discussion so far in terms of the benefits that they would provide. In this section we will consider the impact that they would have in terms of costs.

10.1 AEMO

AEMO would be affected by the proposal for congestion management. This requires a new component of the market settlement to be developed, tested and maintained. We note that some design aspects of our proposal make it simpler to implement than alternatives:

- it relies entirely on information that exists in the dispatch process and hence does not require any new data input arrangements; and
- it is triggered in its operation by data that can be detected in the output of the dispatch process, and hence does not require manual intervention or AEMOs discretion to initiate.

For these reasons we anticipate that once developed there would be little ongoing cost.

In relation to our proposal for partial access, we anticipate that an existing AEMO facility, which allows the dispatch process to be re-run with changes, would be utilised to determine compensation due and compensation payable in relation to non-compliance with the partial access obligations.

This facility is currently provided to market participants on a fee-for-service basis, and hence while we anticipate some additional costs for implementing this new use for that service, we expect that AEMO would recover these costs.

10.2 AER

Under our proposals, we anticipate that the AER could be required to develop, in consultation with the industry, a detailed measurement protocol for the analysis of whether agreed access is being provided. This is not expected to be a major or resource-intensive task.

While we anticipate that the protocol would be subject to occasional review, again we anticipate that this would not be a major task either.

10.3 National Transmission Planner

Under our proposals the National Transmission Planner would have the additional task of determining over a planning horizon the interconnector performance that is to be provided to the market.

This additional task is seen as closely related to the role of National Transmission Planner as it is evolving. Accordingly, we anticipate only minor additional costs.

10.4 Network Service Providers

In relation to Network Service Providers, we are not intending to examine the consequences of different planning outcomes, since the NSP will receive income in relation to each of the assets constructed.

Instead we will focus on the issues that can broadly be called administration costs, as the recovery of these costs may be less clear.

We anticipate some cost reductions and also some cost increases, as follows:

- TNSPs would no longer be required to undertake the demanding RIT-T process in relation to network augmentations for either generator access or interconnector capability reasons;
- for generator access, TNSPs need only analyse alternative access levels and the associated cost of network augmentation;
- for interconnection capability, TNSPs would need only to examine the most cost effective means to deliver the required capability;
- in some cases TNSPs would be charging generators for shared network augmentation. Since they would already be charging for connection, the incremental administrative cost is expected to be small;
- TNSPs would possibly need to deal with applications for increased access level; however it is expected that this would be infrequent and hence involve little cost;
- TNSPs would possibly need to deal with applications for trade of existing access; however it is expected that this would be infrequent as decisions on level of access are not easily changed and hence will be based on forecasts over a substantial period; and
- in the event of a generator with partial access failing to comply with the related operational limit, TNSPs would need to administer the compensation regime. We note that this mechanism is intended to ensure compliance and hence should not need frequent implementation.

11 Relationship to existing Rules

The integrated package of complementary measures described in section 7 has mixed origins:

- some is original;
- some is based on earlier work by a group of generators;
- some is based on intentions that are clear in the current Rules, but which have evidently not been converted into obligations; and
- some is based on further development of an existing provision of the Rules.

The purpose of this section of our submission is to clarify the extent to which our integrated package is evolved from the existing market Rules.

11.1 Protection of agreed access

The Rules show a clear intention that existing access by generators should be protected during the subsequent connection of other generators. For example, clause 5.3.5(d) provides:

> "So as to maintain levels of service and quality of *supply* to existing *Registered Participants* …"

And again, clause 5.4A(e)(2) provides that the TNSP must consider:

> "(2) the potential *augmentations* or *extensions* required to be undertaken on all affected *transmission networks* or *distribution networks* to provide that level of *power transfer capability* over the period of the *connection agreement* taking into account the amount of *power transfer capability* provided to other *Registered Participants* under *transmission network user access* or *distribution network user access* arrangements in respect of all affected *transmission networks* and *distribution networks*."

Hence it is clear that our proposal for the protection of agreed access is merely a proposal to implement intentions that are clear in the Rules (and by implication, the original and current Access Undertakings). However this is not our reason for proposing this measure, and we have justified its inclusion in our package by reference to the National Electricity Objective.

11.2 Locational signals through charging deep connection costs for new entrants

As with protection of agreed access, we find that the Rules already indicate an intention that generators be subject to locational signals based on the cost of any network augmentation necessary to provide the new access sought while maintaining prior access.

For example clause 5.4A(f)(3)(i) provides for:

> "(3) the *use of system services* charge to be paid:
>
> > (i) by the *Connection Applicant* in relation to any augmentations or extensions required to be undertaken on all affected transmission networks and distribution networks; and …"

Further, the clause 5.3.5(d) quoted in part above, goes on to require the NSP to determine:

> "(2) the extent and cost of *augmentations* and changes to all affected *networks*; …"

Again we note that these existing provisions are not necessary to justify the inclusion of the corresponding measure in our package, but we wish to note the extent of continuity between the current Rules and our proposed package.

11.3 Choice of level of access

Allowing a connecting generator a choice of their level of access is clearly contemplated in the existing Rules in clause 5.4A(d)(1), which provides:

> "(d) A *Connection Applicant* may seek *transmission network user access* arrangements at any level of *power transfer capability* between zero and:
>
> > (1) in the case of a *Generator*, the *maximum power input* of the relevant *generating units* or group of *generating units*; …"

While this bare intention is clear, the Rules do not appear to have the necessary provisions to make this concept workable and valuable.

The level of access should logically affect the cost of obtaining access, but the mechanism for ensuring this appears to be absent.

Similarly, the level of access chosen should logically have operational consequences, but again the mechanism for ensuring this appears to be absent.

We are strongly of the view that these deficiencies in application are not a valid reason for abandoning original design intent - quite the contrary.

The measure that we have included in our integrated package builds on this concept in the Rules, but adds to it those provisions that we believe are necessary to convert this simple concept into a workable and valuable part of the transmission frameworks.

As described above we have justified this measure in terms of the NEO and its compatibility with other measures in our package.

In summary, this section of our submission has shown that there is substantial continuity between the existing Rules and our integrated package. This provides some reassurance that these proposals are an evolutionary change from the existing arrangements, and not a radical departure from them.

However, we have not relied at all on this continuity to justify our proposals, but have considered each proposed measure in terms of its effect relative to the National Electricity Objective and its compatibility with other elements of our integrated package.

The continuity from the current Rules derives from clauses 5.3 and 5.4A as noted above. In order to give context to the above discussion we have briefly summarised these Rule clauses in Appendix 1.

12 Distraction affecting consultation process

IPRA was initially surprised by the number of submissions to this review which on their face simply support the status quo.

Following discussions with other participants, we have formed the view that these submissions have been driven by an unfortunate distraction. In the Review of Energy Market Frameworks in the light of Climate Change Policies, the concept of applying generator TUOS over the whole of the NEM was floated.

It retrospect this was particularly unfortunate because, in our view, this concept could never be justified under the National Electricity Objective.

However, this suggestion has, we believe, led to a widespread and understandable fear that this current TFR review could lead to the imposition of generator TUOS to incumbent generators without clear commercial benefits to them. We interpret much of those submissions in support of the status quo as being motivated primarily by an imperative to avoid the risk of imposition of generator TUOS charge on incumbent generators.

It is probably too late now to get additional views on future transmission frameworks that are free from this distraction. However we suggest that it is open to the Commission to reconsider submissions in support of the status quo as seeking to ensure that any changes to transmission frameworks will not disadvantage existing generators. Seen in this light, those submissions would be consistent with a basic tenet of our proposed package.

13 Comments on proposed planning arrangements

IPRA has provided extensive comments in our previous submissions to the AEMC Transmission Frameworks Review Issues Paper[6] as well the AEMC Transmission Frameworks Review Directions Paper[7]. Rather than repeat our previous comments in the body of this submission, we have set out below a brief summary of the key points as previously described. To facilitate referencing we have also provided extracts of the relevant sections of our previous submissions in Appendix 2.

A general point to notes in consideration of transmission planning arrangements is the expected need for augmentation of the transmission network in the foreseeable future. IPRA is of the view that we are likely to see a dramatic increase in the extent of generation investment likely to be required in the coming years, which will be somewhat dependent upon efficient planning arrangements.

13.1 Current planning model not aligned with competitive market

The current economic planning standard reflects a pre-NEM central planning approach in which generation and transmission are evaluated using a collective economic benefit test. This central planning model is suitable for meeting customer reliability needs, but it does not ensure an improvement in the NEO in consideration of interactions between generators and transmission.

[6] See IPRA Submission to the AEMC Transmission Frameworks Review 29 September 2010
[7] See IPRA Submission to the AEMC Transmission Frameworks Review – Directions Paper EPR0019 26 May 2011

The term “open access” is sometimes used when discussing generator access to networks in the NEM. This term is unhelpful however as it is not defined in the Rules, and therefore can be interpreted differently by different parties, which creates confusion.

Generators currently receive common or shared access to the network, which is developed by evaluating the perceived collective interests of the market as a whole. A generator however evaluates market benefits by considering its level of production and the market price.

As it deliberately ignores market prices (as these are in economic terms considered “only wealth transfers”) and considers only changes in production costs, the current regulatory test is quite indifferent to the generators’ commercial returns. As a result it does not provide generators with the transmission services that they need to operate efficiently and effectively in a competitive market.

13.2 Planning outcomes should promote market competition

To overcome the deficiencies of the current planning arrangements, it is necessary to move away from the central planning approach towards competitive market arrangements.

Movement towards a competitive market arrangement can be achieved by ensuring that network services are provided to generators based on a deterministically defined access level. Such an access level can be thought of as being similar to the deterministic planning standards that apply to customer reliability.

In this context, generator access to the market would mean the ability to compete in the market effectively on an orderly basis. The level of access would be specified under specific planning conditions, based on an agreed measurement protocol. This would not be expected to guarantee access, but to provide a reasonable basis for both the Network Service Provider and the generator to understand and commit to an access arrangement.

13.3 Inter-regional planning

The NEM cannot claim to have achieved a truly national electricity market until generators and retailers can confidently enter into hedging contracts across regional boundaries. This is not currently the case due to poor predictability of inter-regional access. Although the new national planning responsibilities for AEMO are a good step, there is no certainty that these revised planning arrangements will provide the necessary level of inter-regional service.

In considering the level of importance of inter-regional planning, it is important to recognise that future inefficiencies will be a more important driver than past experience, due to climate change policies requiring new, more efficient approaches. Inter-regional capacity needs are changing as more renewable energy sources are implemented.

The collective market benefit test referred to above is more appropriate for inter-regional planning than for intra-regional planning, as there is no obvious single user. However individual generators are impacted by inter-regional capacity. For example, one generator may highly value increased inter-regional capacity to enable export into another region, whereas the collective market benefit test might not permit expansion.

14 Comments on proposed connection arrangements

IPRA welcomes the focus that the Commission has placed on connections as part of the TFR. We believe that the current arrangements are not ideal and add to current frustrations with the overall transmission frameworks. We believe that there is scope to improve connections arrangements across the NEM.

Furthermore we believe there is an urgent imperative to do this as the demand for connections is likely to greater than it has been in the past as lower capacity factor plant, delivered in larger numbers of modest capacity allotments[8] are added to the NEM to keep pace with demand growth and government supply-oriented policies such as the renewable energy target (RET).

Our comments on connections in this submission are presented at a high-level in two parts: comments on the existing connection arrangements and comments on the three options presented by the Commission.

It should be noted that IPRA has contributed to a more detailed submission on connections which has been prepared by the Private Generator Group (PGG), and has also contributed to the AEMO Victorian Connections Initiatives Program[9].

14.1 General discussion on connection arrangements in the NEM

The primary focus in relation to the connection process should be to put in place additional measures to counteract the monopoly power that inherently resides with Network Service Providers. We believe that monopoly power, even where not explicitly or openly exercised, has serious and adverse effects throughout the connection process.

The size and sophistication of generation companies has been suggested as mitigating the monopoly power of TNSPs. However, we do not believe that any significant mitigation arises in this way. Furthermore, the market Rules should operate in an even-handed way for all those seeking entry as a generator, and should not rely on generation entrants having any particular characteristics.

There should be a rapid and economical means available to resolve any disputes in relation to connections, with sufficient expertise to overcome any information asymmetry.

We also note that even the availability of an alternative supplier of connection services would not resolve the issue of monopoly power. This is because any such alternative service provider would need themselves to seek connection to the network of the incumbent TNSP. Hence the incumbent TNSP retains an indirect power to impose conditions on the prospective generator.

IPRA is supportive of the Commission's effort to clarify existing aspects of the connections frameworks.

Our overall preference in connections is for a framework that is flexible to accommodate innovative and least cost solutions, open and transparent, gives preference to negotiated

[8] Relative to traditional thermal generation plant which if it were to be installed would be done in larger capacity quanta and via higher capacity factor plant

[9] See AEMO website at http://www.aemo.com.au/planning/connection_initiatives.html (link valid as at 25 January 2012)

outcomes wherever possible and that also provides an efficient and timely dispute resolution mechanism.

In relation to cost allocation for new connections we support generators only being required to pay for their stand-alone connection costs.

14.2 Comments on the connections options presented by the Commission in Chapter 13 of the interim report

IPRA offers the following comments on the three options presented.

Option 1 – Dispute resolution framework

IPRA supports an improvement to the dispute resolution framework, but this measure must complement other measures to improve connections.

Option 2 – Negotiated transmission services

Our preference is for negotiation to form a central tenet of the connections process. However there will inevitably be situations where a difference of opinion arises between a connecting generator (or their agent) and the relevant TNSP. In order to avoid the advantages conferred on a TNSP in this situation an efficient, independent and timely dispute mechanism process should be available to resolve any deadlock in a timely manner (for example within a specified period of time such as 60 days).

Option 3 – Prescribing transmission services for connection

IPRA does not support this proposal due to its complete reliance on regulated outcomes and lack of any competitive tension in delivering transmission services for connection.

15 Glossary

Abbreviation	Description
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CO_2	Carbon Dioxide
CPI	Consumer Price Index
CPT	Cumulative Price Threshold
DPRG	Dispatch and Pricing Reference Group
EOM	Energy Only Market
ETS	Emission Trading Scheme
FCAS	Frequency Control Ancillary Service
FIT	Feed In Tariff
IPRA	International Power-GDF Suez Australia
LNG	Liquid Natural Gas
LRMC	Long Run Marginal Cost
MPC	Market Price Cap
MWh	Mega Watt Hours
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Regulation
NSP	Network Service Provider
O&M	Operation and Maintenance
PGG	Private Generator Group
RET	Renewable Energy Target
RIT-T	Regulatory Investment Test - Transmission
RRP	Regional Reference Price
SACP	Shared Access Congestion Pricing
TFR	Transmission Frameworks Review
TNSP	Transmission Network Service Provider
TUOS	Transmission Use of System
VEET	Victorian Energy Efficiency target

Appendix 1 – Summary of relevant Rules

Rule 5.3 (establishing or modifying connection):

- establishes processes for connection Enquiry by applicant, Response by NSP, Application by applicant and Offer to Connect from NSP;
- requires NSP and applicant to share various information including technical, fees & costs, relevant standards;
- allows for negotiation between NSP and applicant on various matters, including access standard;
- NSP must use reasonable endeavours to provide Offer to Connect which meets the applicants reasonable requirements, including power transfer capability; and
- finalised Offer to Connect becomes part of the connection agreement.

Rule 5.4A Access arrangements relating to Transmission Networks

- generator applicant may seek access at any level from zero to max power output;
- NSP must use reasonable endeavours to provide the access arrangements being sought subject to good electricity industry practice considering;
- connection assets to be provided;
- all [consequential?] potential augmentations or extensions; and
- applicant and NSP must negotiate in good faith re:
    - connection service charge to be paid by applicant for connection assets provided by NSP;
    - use of system charge ; and
    - access charges for:
        - compensation paid by NSP to participants for being constrained;
        - compensation paid by participants to NSP for causing other participants to be constrained; and
        - maximum negotiated use of system charge that NSP can seek must be in accordance with Part J of chapter 6A.

Schedule 5.1 Network Performance Requirements

- describes planning and operating criteria which NSPs must apply, and requirements on NSPs in determining appropriate technical requirements for connection enquiries;
- two categories of obligations:
    - to achieve network power transfer or QOS for common good of all; and
    - to achieve specified level of network service at individual connection point.

Appendix 2 – Planning arrangements

This appendix contains extracts from IPRA's previous submissions to the Transmission Frameworks Review. The main points have been summarised in section 13 of this submission, however the previous extracts are reproduced here for convenience.

Extract from IPRA Submission to AEMC Issues Paper

Current Generator Access

As discussed under Q2, generators do not receive a defined level of service from the TNSP, but instead have common access to network infrastructure that is developed according to the perceived collective interests (the "market benefit") of the market as a whole. The "open access" arrangement often referred to by TNSPs and market institutions remains an undefined term in the Rules and as such is ambiguous.

In this context, "common access" means that all generators have equality of access to the shared network in both the connection and dispatch phases; although disorderly bidding under the current spot market design means the nature and implications of this "equality" in dispatch can sometimes be unclear. Under this regime, the shared transmission network becomes a common good, with all of the economic problems that are known to be associated with such goods. In particular, a new generator connecting to and making use of the common network will impose costs (in the form of increased congestion) on existing generators. It does not need to take account of these costs in deciding when and where to connect.

Unlike a conventional common good situation, the common network is not a fixed resource, but may be expanded from time to time, in accordance with an "economic planning standard". That is, the decision whether to expand will be predicated on whether the expansion is economic (ie market benefits exceed project costs) from the point of view of the market as a whole.

> *Example, in Southern Queensland, Roma power station 1 and 2 (both rated at 40MW) had unconstrained access to the market via the Tarong 275/132kV transformers. This unconstrained access generally allowed both Roma units to be fully dispatched. This lasted until very recently, when Condamine power station connected onto the same part of the network with 144MW of generation. During commissioning, this has led to a reduction in access with increased volume and financial risk to Roma power station especially during high priced periods.*

The economic planning standard is a legacy of the pre-NEM central planning regime, where all investments – transmission and generation –were predicated on collective economic benefit. But, in the context of a competitive, decentralised generation market, this "echo" of the old regime is anomalous and, as we shall argue, economically inefficient and counterproductive.

The discussion on the problems of an economic planning standard assumes that there is a common language within which costs and benefits can be compared. But this is not the case:

- a generator will evaluate benefits in terms of increased production receiving the market price; and

- the regulatory test deliberately ignores market prices (as these are "only wealth transfers") and considers only changes in production costs

A simplified example is useful to illustrate these problems. Suppose that generator A (with considerable transmission planning expertise), identifies a transmission expansion project which would cost $80m but deliver benefits – to generator A – of $100m. In any open, competitive market, such a "win-win" situation would likely lead to a supplier agreeing to develop the project, with a price being negotiated that split the net benefit of $20m between the two parties.

Under an economic planning standard, however, the TNSP must consider the benefits accruing not just to generator A but to all market participants. For simplicity, lets us assume that the only other affected party is generator B, who will become $70m worse off if the expansion project is built. The total benefits – of $30m – are now less than the $80m cost and so the project may not be built3 under the existing planning regime. In our terminology, the economic planning standard dictates that the new project is not required or justified.

Why should regulation prevent a TNSP from building a project whose equivalent in a competitive context would certainly be developed? A central planner's response would be: because the project is uneconomic, as demonstrated by the fact that it delivers total benefits less than its cost. The validity of this response rests on the implicit assumption that central planning is superior to decentralised planning. But this runs counter to the general experience that decentralised planning works best. Put another way, why go to the trouble of setting up a decentralised generation market? We must look beyond the central planner's world view.

A more sophisticated response is that the project would impose a cost – an "externality" – on a third party: generator B. But externalities are not always "bad things" that must be avoided. For example, if a new power station is built, this will tend to reduce the price of electricity and so create costs – negative externalities – on other generators. Should a new power station be prohibited unless the collective benefits exceed the cost?

Thus, we need to consider the nature of the externality to understand whether regulation is required to prevent it occurring. It might be that the new project causes a reduction in generator B's access to the network. This can happen in transmission networks. We would agree that such externalities should be prevented.

However, the increase in access to Generator A causes generator B to be displaced in the merit order and so receive a lower level of dispatch and hence revenue. This is simply the nature of a competitive market. We do not believe it is appropriate to seek to prevent this occurring.

Let us examine this latter scenario more closely. Suppose that, at a point in time, the spot price is $1000 per MWh and the fuel costs of generators A and B are $10 per MWh and $15 per MWh, respectively. Let us further suppose that the new network investment would allow generator A to be dispatched by an additional 100MW and, as a result, generator B's dispatch is reduced by 100MW.

The hourly benefit to generator A of the network investment is 100*(1000-10) = $99,000. The corresponding cost to generator B is 100*(1000-15) = $98,500. So, the collective benefit is just $500, which is predicated on the difference in fuel costs: 100 * (15-10).

This illustrates the fundamental problem with the economic planning standard. The character of the collective benefit (driven by fuel cost differences) is entirely different to that of the individual benefit (driven by market prices). Market prices and revenues never feature in the calculation of collective benefit, because they only affect the "wealth transfers" between different parties and, at an aggregate level, these wealth transfers must always sum to zero.

Therefore, under an economic planning standard, the primary concern of generators – market revenue – is not simply misunderstood or neglected. It is, by definition, entirely ignored. So, here we have the essence of the current planning regime. A TNSP is obliged to ignore the primary interests of half of its customer base. So how does a potential generation investor regard a situation where its only access to market is governed by a regulatory framework that is entirely indifferent to his commercial concerns?

The source of these issues is the existing design of the transmission access regime: specifically, the so called "common access" provision combined with the economic planning standard. The following discusses how changes to this design could substantially reduce these risks.

> *Example - the South East area of South Australia has been identified as a wind generation corridor. During high wind generation the South East transformers quite frequently, reach their nominal line ratings and cause their respective system normal constraints to bind. This leads to the constraining down of Snuggery, Ladbroke Grove and Lake Bonney power stations. This is a known problem with the relevant TNSP and it is well documented as an issue in their respective planning documentation. However, there are no signs of fast tracking the installation of the 3rd South East transformer, which would allow full flows across the SA to Vic interconnector and minimise the constraining down of Snuggery, Ladbroke grove and Lake Bonney power stations. Consequently, Snuggery's level of access has reduced and this has created a financial risk for Snuggery by reducing their ability to sell caps in the financial market.*

This is a good illustration how existing assets are harmed by the current regime and is coupled with reduced contract liquidity at the same time.

Deterministic Standard

One approach to addressing the shortcomings of an economic planning standard would be to introduce a "deterministic" planning standard for generation access. To illustrate what is meant by this, we will consider the characteristics of the deterministic planning standard that applies to the demand side.

A deterministic standard is an access standard that applies under specified planning conditions. For example, an N-1 standard requires that demand must always be met under N-1 network conditions. "Demand must always be met" means that the level of "access" for demand must be equal to or greater than the anticipated maximum demand level. The "N-1" condition refers to a set of planning conditions under which only one network element is out of service.

A deterministic standard provides some level of surety for an electricity customer, in that load will only be shed (due to transmission limitations) outside of N-1 conditions (say). It also allows different classes of customers to receive a different standard: for example, critical load areas such as CBDs might have an N-2 planning standard. It also means the customer will receive that standard irrespective of whether it is "economic" according to a "collective net benefit" approach. The uncertain effects of the economics of network planning do not lead to an uncertain service level for a customer. We believe that these are characteristics that are valuable for, and should be provided to, the generation side also.

A corresponding deterministic standard for generation would state that generator access to the market must equal or exceed a specified level chosen by the participant ("X" MW) under specified planning conditions.

Unlike the standard for customers, the relatively small number of generators allows the levels to be individually chosen, with consequent efficiency advantages. As with the demand-side standard, verification that the standard is maintained would be through planning studies, not by monitoring actual access levels: although these might be an indicator that something is amiss.

This deterministic standard is defined in terms of "access to the market". We consider "access" to be defined. "Access" means the ability to compete in the market, whereas "market" refers to the regional market.

The calculation of a level of access can be achieved via planning studies of the electrical network. In order to ensure that this process is meaningful, the planning studies would need to be conducted with a standardised set of assumptions, which could be regarded as a "measurement protocol",

The actual level of access, in operation, will vary from time to time due to the many factors that influence network capability but the access seen in the planning study will provide a "common language" to enable a prospective participant to compare the available access at alternative locations or with alternative network augmentations.

Establishing a deterministic or "defined" access level of X MW provides a generator with the opportunity to choose the level of X: the higher the "X", the greater the access. This is discussed further under Q7

Inter-regional Access

Inter-regional access essentially refers to the effective capacity of the interconnectors to transport energy from one region to another. Historically, the networks that now comprise the market regions were developed as largely self-sufficient entities. This characteristic has carried over into the current market environment to a large extent.

However, the continuation of this characteristic should not be assumed for the future, and the geographical distribution of some renewable energy sources suggests that inter-regional capability will become much more important over the coming years.

As with generator access, inter-regional access is subject to an economic planning standard, whereby expansion is predicated on collective benefit to the market as a whole. This approach is more understandable in the inter-regional context, as there is no single, identifiable user to whom the inter-regional service is being provided, and who is able to choose an efficient level.

Nevertheless, individual generators will be impacted by the level of interregional access, particularly those operating in a small region such as SA and reliant on the "export market" of other regions. Therefore, problems can arise, analogous to those described in the previous section, where a potential inter-regional expansion is highly valued by one or more generators but, due to "negative externalities" on other parties, is not permissible under the economic planning standard.

In recent years, interconnector performance has been worsening as indicted by the actual performance illustrated in our response to question 2 However, it is unclear how much of this is due to the planning standards, per se, and how much due to the other factors described later in this submission: the lack of obligation to maintain planning standards; unclear accountability between multiple TNSPs and the NTP; and the adverse and dysfunctional impacts of intra-regional congestion on interregional flows.

While it is to be hoped that the National Transmission Plan (NTP) will be effective in giving enhanced certainty of inter-connector capability, this remains unproven. The detailed nature of the network limitations that have undermined the expected capability of inter-connectors in the past leaves us with a concern that the NTP will be conducted at too high a level of abstraction to be effective in this regard.

In the light of these considerations, we would emphasise the importance of certainty and reliability of inter-regional access, but we are not convinced at this stage that this is best addressed by introducing defined access standards. Nevertheless, we think that consideration of alternative planning standards for interconnectors should be a part of the AEMC review. In such an alternative regime, it could be considered that the planning body would act of proxy for those participants affected by inter-connector capability, and would take an appropriately long-term view to give them assurance both in investing in generation and in hedging its output.

Extract from IPRA Submission to AEMC Directions Paper:

IPRA sees a need for the planning of transmission investment to be separately considered for different circumstances. In the following discussion we will make suggestions in relation to three different circumstances.

Network investment to support generator access

IPRA believe that efficient investment in transmission in support of generator access will be achieved if the basis is an informed choice by the prospective generator on the place and level of access.

To allow an informed choice the prospective generator needs to know prior to this decision:

- the costs that they will incur as a result of that choice; and
- the operational consequences of that choice, as far as they can be reasonably forecast.

We have further proposed that the costs faced by the generator should be those necessitated by that choice of location and access level. We recognise that there is a role for the Network Service Provider in making design choices to facilitate the anticipated further development of the network, but recommend that such choices if made by any party other than the generator should neither increase the cost to the generator nor delay their connection.

Investment to support interconnector capability

We have provided evidence in our earlier submission to this review of very restricted interconnector capability. We have attributed this poor performance to the regional segregation of transmission network planning.

The recent introduction of a National Transmission Plan might be expected to improve this situation. There has not yet been sufficient experience to indicate whether or not this will improve the situation as it is currently structured. However, we believe that there is already evidence available which suggests that a refinement to the process is desirable.

Our concern is that the National Transmission Plan, of necessity, must deal with the transmission network in a "broad-brush" manner, focussing on the major transmission paths. In contrast, our experience in actual market operations leads to the conclusion that limitations on interconnector flows are commonly due not to limitations within these major transmission paths, but rather to limitations associated with plant embedded deep within one of the connected regions.

Hence we see a significant risk that the real limitation on interconnector flows will be "below the radar" in the context of the national Transmission Planning.

We propose that rather than the NTP seeking to indicate where investment is needed to give desirable interconnector capability, the NTP should rather indicate the level of reliable interconnector capability it considers desirable for each interconnector and flow direction.

It would then be the responsibility of the relevant TNSPs to ensure in their planning that they did not encroach on that capability.

We see this as giving the need for interconnector capacity and reliability (as determined by AEMO) an equal status with jurisdictional planning standards. It also supports the different planning approaches between TNSPs provided the indicated level of interconnector capability and reliability are satisfied.

Investment to support reliable supply to customers or market benefits

The issues of investment to support reliable supply to customers or to gain market benefits are clearly the focus of RIT-T test and we anticipate this if the issues for which this test is unsuitable are segregated then the test will service its intended purpose.

In saying this we are not assuming that the RIT-T is now fully developed, but rather we are suggesting that for these particular purposes the path for improvement lies in refining the test rather than replacing it with another mechanism.

Appendix 3 – Evidence of large uncertainty in network limits

In this submission we have argued that a major reason that our proposals differ from the options given in the first interim report is that we recognise that there is commonly great uncertainty in relation to future network limits. Our proposals are designed to improve efficiency in this environment of uncertainty.

The aim of this appendix is to provide evidence in support of our contention of network limit uncertainty.

For this purpose we rely on data collected by AEMO for presentation to the Dispatch and Pricing Reference Group (DPRG), a group to which IPRA provides one of several representatives on behalf of NEM generators.

This information has been modified slightly to improve clarity, and is provided here with the agreement of the chair of the DPRG.

The table highlights the variation in network constraints from the pre-dispatch (day ahead) forecast to the actual outcome in dispatch. The column headed "Number of dispatch intervals" indicates how may 5 minute dispatch periods that the difference between the pre-dispatch forecast and the actual dispatch outcome was significant. The "Max difference" column shows the maximum difference in percentage terms between the pre-dispatch forecast and the dispatch outcome.

In summary, the table highlights the fact that critical network constraint outcomes in dispatch can deviate from the pre-dispatch forecast by very large amounts, and for significant amounts of time.

We believe that this information does not indicate any shortcoming in the development or application of the constraints representing network limits. On the contrary, we believe that this information indicates the inherent difficulties of forecasting network limits, even close to real time and with the wide range of information available to AEMO.

Clearly the task of forecasting network limits becomes more difficult if longer term forecasts are sought, and if less comprehensive information is available to the forecaster. Hence we see the information presented as representing the best forecasting that is achievable and emphasise that in the context of forecasts by participants, and over longer periods the uncertainties would be greater.

Interconnectors	Number of dispatch intervals	Max % Difference[10]	Comments
Directlink (Queensland to New South Wales)	1463	185	The difference arises because some of the values used in the pre dispatch version of the equation are based on estimates
Murraylink (Victoria to South Australia)	781	404	The dispatch equation includes the Waterloo wind farm trip scheme and it is not possible to model that in the pre-dispatch version of the equation. A method to include this control scheme in the pre-dispatch equation is being investigated.
Directlink (Queensland to New South Wales)	249	12032	Constraint archived as per limit advice from TransGrid
Directlink (Queensland to New South Wales)	177	265	The difference arises because the values used in some pre-dispatch terms are based on estimates
Victoria to New South Wales, Heywood (Victoria to South Australia), Murraylink (Victoria to South Australia)	130	58	Dispatch and pre-dispatch formulations are closely aligned. Can't be readily improved
Victoria to New South Wales, Heywood (Victoria to South Australia), Murraylink (Victoria to South Australia), Basslink (Victoria to Tasmania)	126	26	Pre-dispatch formulation reviewed. Currently meets best practice
Victoria to New South Wales, Murraylink (Victoria to South Australia)	94	17	pre-dispatch formulation reviewed. Currently meets best practice

[10] PU difference = abs ((Dispatch RHS-Predispatch RHS)/(Dispatch RHS)), converted to percentage and rounded by IPRA in this version.

Interconnectors	Number of dispatch intervals	Max % Difference[10]	Comments
Heywood (Victoria to South Australia)	80	36	The difference between the dispatch and pre-dispatch equations is due to the difference of the forecast and actual values of South Australian load and wind farm generation. In addition, the pre-dispatch equation updates every 30 minutes interval while the dispatch updates every 5 minutes. This cause the difference to increase towards the end of the 30 minutes dispatch interval.
Heywood (Victoria to South Australia)	80	19	The difference between the dispatch and pre-dispatch equations is due to the difference of the forecast and actual values of South Australian load and wind farm generation.
Victoria to New South Wales, Heywood (Victoria to South Australia), Murraylink (Victoria to South Australia), Basslink (Victoria to Tasmania)	68	35	Constraint is an offset to existing "system normal" equations, and has same limitations in pre-dispatch as the NIL equation
Heywood (Victoria to South Australia)	53	3355	The difference between dispatch and pre-dispatch values are due to the washout term used to select the correct equation based on status of the South East capacitor
Victoria to New South Wales, Heywood (Victoria to South Australia), Murraylink (Victoria to South Australia), Basslink (Victoria to Tasmania)	50	97	Constraint is an offset to existing NIL stability equations, and has same limitations in pre-dispatch as the NIL equation
Victoria to New South Wales, Heywood (Victoria to South Australia), Murraylink (Victoria to South Australia), Basslink (Victoria to Tasmania)	48	42	Constraint is an offset to existing "system normal" equations, and has same limitations in pre-dispatch as the NIL equation

Interconnectors	Number of dispatch intervals	Max % Difference[10]	Comments
Heywood (Victoria to South Australia)	48	3041	The difference between dispatch and pre-dispatch values are due to a term used to select the correct equation based on status of the South East capacitor.
Murraylink (Victoria to South Australia)	46	33	The difference between the dispatch and pre-dispatch equations is due to the difference of the forecast and actual values of the Riverland area load
QNI (New South Wales to Queensland), Victoria to New South Wales, Heywood (Victoria to South Australia), Murraylink (Victoria to South Australia), Basslink (Victoria to Tasmania)	43	840	Constraint is an existing “system normal” equations, and has same limitations in pre-dispatch as the NIL equation
Victoria to New South Wales, Heywood (Victoria to South Australia), Murraylink (Victoria to South Australia), Basslink (Victoria to Tasmania)	37	15	Constraint archived - no longer in use
Victoria to New South Wales, Heywood (Victoria to South Australia), Murraylink (Victoria to South Australia), Basslink (Victoria to Tasmania)	36	2967	Constraint is an offset to existing “system normal” equations, and has same limitations in pre-dispatch as the NIL equation
QNI (Queensland to New South Wales), Victoria to New South Wales, Heywood (Victoria to South Australia), Murraylink (Victoria to South Australia), Basslink (Victoria to Tasmania)	34	35	Constraint is an offset existing “system normal” equations, and has same limitations in pre-dispatch as the NIL equation
Victoria to New South Wales, Heywood (Victoria to South Australia), Murraylink (Victoria to South Australia), Basslink (Victoria to Tasmania)	33	29	This constraint is an offset to existing “system normal” equations , and has same limitations in pre-dispatch as the NIL equation

Interconnectors	Number of dispatch intervals	Max % Difference[10]	Comments
Heywood (Victoria to South Australia)	32	23	The difference between the dispatch and pre-dispatch equations is due to the difference of the forecast and actual values of South Australian load and wind farm generation. In addition, the pre-dispatch equation updates every 30 minutes interval while the dispatch updates every 5 minutes. This cause the difference to increase towards the end of the 30 minutes dispatch interval.
Directlink (Queensland to New South Wales)	28	137	The differences in the pre-dispatch value of the equation on different occasions were mainly due to one of the following reasons: amount of Condong generation during outage of 758, unpredictability of a control scheme status, and unpredictability of Terranora import/export levels.
Victoria to New South Wales, Murraylink (Victoria to South Australia)	27	50	Constraint archived - no longer in use
Victoria to New South Wales, Heywood (Victoria to South Australia), Murraylink (Victoria to South Australia), Basslink (Victoria to Tasmania)	26	38	Constraint is an offset to existing “system normal” equations and has same limitations in pre-dispatch as the NIL equation
Murraylink (Victoria to South Australia)	25	18	The difference between the dispatch and pre-dispatch equations is due to the difference of the forecast and actual values of the local area load
Heywood (Victoria to South Australia)	25	13	The difference between the dispatch and pre-dispatch equations is due to the difference of the forecast and actual values of South Australian load and wind farm generation
Victoria to New South Wales, Heywood (Victoria to South Australia), Murraylink (Victoria to South Australia), Basslink (Victoria to Tasmania)	24	2619	Constraint is an offset to existing “system normal” equations, and has same limitations in pre-dispatch as the NIL equation

Interconnectors	Number of dispatch intervals	Max % Difference[10]	Comments
Victoria to New South Wales, Heywood (Victoria to South Australia), Murraylink (Victoria to South Australia)	24	51	Dispatch and pre-dispatch formulations are closely aligned. Can't be readily improved.
QNI (Queensland to New South Wales), Victoria to New South Wales, Heywood (Victoria to South Australia), Murraylink (Victoria to South Australia), Basslink (Victoria to Tasmania)	21	22	Constraint is an offset to existing “system normal” equations , and has same limitations in pre-dispatch as the NIL equation
Victoria to New South Wales, Murraylink (Victoria to South Australia)	20	31643	Pre-dispatch formulation is identical to the dispatch formulation - Can't improve alignment