International Power Australia

Submission to the AEMC Transmission Frameworks Review

29th September 2010

Executive Summary

This submission considers the effects of the transmission framework on the investment environment for existing and potential new entrant generators. This is because the major issues with the existing transmissions system directly impact on generators.

A key point is that existing generator investments should not be treated as a sunk cost. The transmission framework does impact on the commercial viability of these investments which in turn will affect the level of new investment in the generator sector.

Given the experience of current investments, transmission represents a major source of risk for any new generation investment. This provides the context for this submission.

IPRA supports the view that the outcome of the review should be a coordinated package of measures, including:

- enhanced certainty of ongoing market access for generators;
- certainty of any costs associated with connection and market access;
- efficient and complete locational signals for new entrant generators;
- a complete congestion management regime to reduce uncertainty, enhance dispatch efficiency, and improve the effectiveness of SRA units for the management of inter-regional price risk; and
- re-consideration of the planning of inter-connector capability with a particular focus on the predictability of this capability as generators are likely to become increasingly reliant on interconnectors as part of their route to market.

In addressing the questions raised throughout the Issues Paper, International Power Australia (IPRA) makes the following observations.

Application of the NEO

Minimisation of total costs is a central planning perspective.

The objective of transmission should be to facilitate and support competition in generation.

Historical evidence of inefficiency is, at best, indicative of future trends. However, it is the projected future that must be the driver of reform.

Repeatedly reviewing these issues creates its own risks and inefficiencies, especially as they relate to heightened perceptions of regulatory risk.

Locational signals are currently incomplete.

The role of transmission

TNSPs are infrastructure rather than service providers, and:

- accept no responsibility to provide a defined level of service to individual users, particularly generators.
- are required to perform multiple roles, some of which conflict.
- are viewed as low risk businesses, not exposed to market signals and risks. This can be anomalous since they act within, and impact, upon a high risk market.

Despite the establishment of the NTP, the regional roles of TNSPs may lead to ineffective inter-regional service provision.

Transmission planning

Generators currently receive *common access* to a network that is subject to an *economic planning standard*. This access does not provide generators with the transmission service they need to operate successfully and efficiently in a competitive market.

Generators require a defined access level, similar to the deterministic planning standards that apply to the demand side.

The current predictability of inter-regional access is poor, and there is no certainty that the revised planning process will overcome this.

Promoting efficient transmission investment

TNSPs are not obliged to maintain the economic planning standard and the current NTP planning regime remains unproven. Accountability for inter-regional planning is unclear.

Demand-side planning standards should consider absolute cost – as well as the (risk-adjusted) expected cost – of transmission failure.

A scenario-based planning should be used to ensure robust planning under uncertainty.

The RIT-T should be maintained to serve some specific purposes, but augmented by separate regimes to reflect any changes to planning objectives and standards.

Economic regulation of TNSPs

The regulatory incentive on a TNSP to minimise planning and development costs may conflict with efficiency objectives, and bias the decision in choosing between network and non-network solutions.

Network charging for generation and loads

Generators should not bear sunk costs associated with historical decisions.

However, generators should bear the network costs associated with their locational decision.

Any charges should not seek explicitly to achieve climate change objectives.

Incentives relating to power station closure are best provided by making access tradeable.

Nature of access

A "base" access level must be defined before an "enhanced" level can be considered.

Defined access must be maintained throughout the life of the power station. In doing so, a mechanism is required for preserving access level and preventing subsequent new generation from unreasonably encroaching on it.

Enhanced access could be predicated on a wider range of planning conditions under which access must be provided.

Connection arrangements

Defined access levels should be negotiated and specified in the connection agreement.

Network operation

Appropriate regulator incentives and obligations are needed to ensure TNSPs' efficiency in their Operational and Information Provider roles.

Dispatch of the market and congestion management

An intra-regional congestion management regime is needed.

A complete congestion management regime will be more effective and easier to implement than a partial regime.

Any new congestion management regime needs to conform to certain high-level principles.

The allocation of risk arising from congestion should be considered in this review.

Signed

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Introduction

Overview

International Power Australia (IPRA) is the largest private investor in electricity generation in Australia, with assets in Vic, SA, and WA. IPRA has persisted in investing in the Australian NEM while others have exited.

As an international company, IPRA has a wide choice of where it invests its scarce capital. Multiple factors influence that decision, many of which are outside the scope of this review. But "access to market" will be a critical factor for any investor in any market, and it is certainly critical for us.

In the NEM, generator access levels are become increasingly uncertain as transmission network utilisation increases and the frequency and intensity of congestion grows. In our view, the current transmission frameworks will not and cannot provide the level and character of access that investors in a competitive generation market require. We would expect our global competitors – to the extent that they are aware of the issue - to be thinking along similar lines.

Efficient and timely generation investment is becoming increasingly critical for the NEM. The excess capacity – particularly base load capacity – that the NEM inherited is all but taken up. Climate change policies are likely to accelerate replacement of existing capacity. In the current economic climate, attracting the global capital required to fund the NEM's investment needs will always be challenging. We need to do everything possible to remove unnecessary obstacles or impediments to this investment.

The NEM investment climate will remain challenging. IPRAs experience is that it is relatively easy to secure finance for a new coal fired generator in Asia over a 20 year term, whilst a 5 year term for an existing coal fired generator in Australia is very difficult.

Structure of Submission

In this submission, the responses align with the questions that are posed in the Issues Paper. We have sought to avoid repetition, so where there is an issue that is relevant to several questions, we aim to discuss it under the heading of the question to which it is most pertinent. In this respect, individual responses taken in isolation may not be comprehensive.

IPRA is cognisant this is an issues paper and that the AEMC is not consulting on – or seeking – potential solutions at this stage. However, in some areas, we have considered it helpful to outline our proposed solution to an issue. We believe this can be helpful to the review at this stage in a number of ways. Firstly, it is helpful in explaining and articulating the issue. Secondly, may demonstrate that resolving the issue is not intractable and that there is at least one practical solution available.

Finally, and perhaps most importantly, it illustrates what is possible and permissible within the overall "open access" philosophy of transmission within the NEM. Past reviews narrowly interpreted the open access "domain" and has caused options to be implicitly ruled out even before they have been identified or properly explored. The MCE terms of reference gives the AEMC licence to think broadly and fundamentally about issues and solutions. IPRA hopes the AEMC makes the best use of this opportunity.

Question 1: Application of the NEO

"Do frameworks governing electricity transmission allow for the minimisation of total system costs and for overall efficient outcomes in accordance with the NEO? What evidence, if any, is there to demonstrate that this is or is not the case?"

Minimisation of total costs is a central planning perspective. A major objective of transmission should be to facilitate and support competition in generation

Historical evidence of inefficiency is, at best, indicative of future trends. However, it is the projected future that must be the driver of reform

Repeatedly reviewing these issues creates its own risks and inefficiencies.

Historical evidence of inefficiency may be hidden or obscured

Locational signals are currently incomplete

Central planning and decentralised planning perspectives

IPRA agrees that the NEO means the promotion of efficiency, which is broadly analogous to the "minimisation of total system costs". However, the emphasis on "minimisation" and "total system" suggests a central planner's perspective which, in our view, is indicative of much of what is wrong with the existing transmission framework.

Specifically, TNSPs are required to plan and expand their networks as though they are central planners, seeking to minimise total costs or, in the language of the RIT, to "maximise market benefits". It is as though transmission continues to live and operate as it did in the pre-deregulation, centrally-planned industry, oblivious to the creation of competitive markets all around.

TNSPs cannot themselves be competitive, but they can be required to act so as to support competition. Specifically a "service provider" to a competitive market must be able to design its service and provide information to support the needs of competing participants, must define and maintain service levels and standards, and must offer a range of services to reflect the diverse needs of its customer base. The existing transmission framework allows TNSPs to do none of these things.

It is time to move away from the central planning mindset and to think instead how transmission frameworks can be designed so as to best support and facilitate competitive markets. It is those markets that are the best guarantors of long-term efficiency.

IPRA contends that the NEO is best achieved by reducing the role of central planning in relation to generator access and increasing the scope for participant choices.

Historical evidence is at best indicative

Future inefficiency not historical inefficiency must be the key driver of reform. We do not know the future, but nor do we know that history is a good guide to it. Given the pre-NEM legacy of overbuilt, oversized transmission networks, it is reasonable to assume the problems associated with transmission constraints – congestion and restricted access – will grow over time, but there is no reason why these should grow smoothly or linearly. Indeed, as the AEMC's Review of Energy Market Frameworks in light of Climate Change Policies found, the onset of climate change policies is likely to mean a break from the past, giving rise to quite different use of – and challenges for – transmission.

Furthermore, from the perspective of individual current or prospective market participants, it is not the aggregate or expected level of inefficiency that is relevant, but the distribution of, and uncertainty around, these aggregates. It is of little comfort to one generator hard hit by the impact of congestion that a competitors enjoys corresponding benefits. It is similarly of little comfort to a potential investor who has decided not to invest because of perceived access risks that such concerns never eventuated.

These issues should be considered in terms of their impact on the individual participants who make up the competitive market.

Regulatory risk from continuing reviews

Some of the issues set out in the Issues Paper – for example, intra-regional congestion or locational signals for generation – are being subjected to perhaps their third or fourth review. Previous reviews have opted for "do nothing" or "do very little" in these areas. But the very fact of repeated reviews suggests that stakeholders believe that there will be an eventual need for substantial reform to address these issues.

For current or prospective market participant, this situation is unsettling. Their concern will not be so much about *when* the issue will be addressed but rather about *how* it will be addressed and, most importantly, what this will mean for the value of business models and sunk assets.

In short, *not* addressing these issues creates a substantial amount of regulatory risk. For an investor, regulatory risk is quite different in nature to market risk. Compared to assessing market risk, regulatory risk analysis involves making a greater number qualitative judgements. Regulatory risk is difficult to deal with, and perceptions that it exists can be a major disincentive for new investors.

Historical Evidence may be obscured

Evidence of dynamic inefficiency is, by its nature, obscure. A potential generator investor may have "walked away" from the NEM because of, for example, the transmission access risks. How would we ever find out? Even if we know – at a high level – that a project has been cancelled, deferred or relocated, we are unlikely to know the reasons for this and whether, under a different transmission framework, things may have turned out differently.

Evidence of inefficiency in transmission investment is even harder to come by. It would be unexpected if a TNSP took the trouble to apply the RIT to an economic project and then, when the test was passed, declared that it would not be investing. We know about investments that occur and also about projects that fail the RIT. We can know nothing about projects that would have been economic, but that were never identified or tested. At best, we can look at continuing congestion and speculate: "surely there must be some economic way to remove this".

Even "smoking gun" evidence of static inefficiency – disorderly bidding, counterprice interconnector flows and so on – may be misleading. It will typically be in generators' interests to prevent inter-regional congestion developing, because such congestion simply forces down the price in the exporting region and reduces the export capacity of interconnectors.

Generators will have some moderate strategic ability to minimise congestion and they are incentivised to use this.

This is not to dispute that the AEMC should be gathering all of the historical evidence that is available. It is simply to point out that this empirical evidence is just one factor, perhaps a relatively minor factor, that the AEMC needs to consider in this review.

Locational signals are currently incomplete

In order to meet the requirements of the NEO, the transmission framework should provide prospective generator entrants with efficient locational signals. By efficient we mean signals that are neither inflated by the allocation of unrelated costs nor diminished by the omission of necessary costs.

We will discuss this further in relation to question 6, but briefly –

- New generators have not been faced with a locational signal related to the cost of network augmentation to support their access, and
- The congestion effects of a new generator in many cases are imposed largely on other generators and hence this signal is greatly understated from the perspective of the new entrant

Examples

Three examples illustrate the impact that incomplete locational signals can have. The installation of the Lake Bonney windfarm in the South East of South Australia and subsequent expansion of Lake Bonney in 2009 has severely impacted Snuggery and Ladbroke Grove power stations.

Incomplete locational signals facilitated Yallourn unit 1 in obtaining the facility to connect onto the 500kV system via the Hazelwood transformers and the connection of Bairnsdale power station. These changes are now having a material impact on Hazelwood power station.

Similarly, the advent of Basslink connecting to the Loy Yang Power Station switch yard has caused significant risk to Loy Yang A and B power stations as well as Valley Power gas turbines. The risk applies during a network outage between Loy Yang Power Station and Hazelwood.

We note that network investment and congestion are, to a substantial extent, alternatives. Hence both should be accurately signalled to allow the prospective generator to make an economic choice.

The numerous other locational signals that a new generator is subject to, such as fuel supply and transport costs, cooling water costs, transmission losses etc, all have their own relevance, but do not substitute in any way for these missing locational signals.

Question 2: The role of transmission

“Is there a need to consider the appropriate future role of transmission in providing services to the competitive sectors of the NEM? What evidence, if any, is there to suggest that the existing service provided to facilitate the market, or the definition of this service, is inappropriate or insufficient?"

The existing role of TNSPs is to be an infrastructure provider rather than a service provider.

A TNSP currently accepts no responsibility to provide and maintain a defined level of service to individual users, particularly generators.

As infrastructure provider, a TNSP is required to perform multiple roles, some of which conflict.

A TNSP is established (by regulation and culture) as a low risk business, and is not exposed to market signals and risks. This can be anomalous since it is acting within, and impacting upon, a high risk market.

The regional roles of TNSPs may lead, despite the establishment of the National Transmission Planner, to ineffective inter-regional service provision.

A TNSP is an infrastructure provider not service provider

In other industries, a typical "service provider" would, as a minimum, describe and define the service that it offers to customers. Ideally, a choice of services would be offered. A customer would select a service based on the value that it provides compared to the service price.

A transmission service provider (TNSP) is labelled as a "service provider" and it is generally assumed that its "customers" are the network users: generators, distributors and major customers. But, in this context, how is it that there is no definition of the service that is offered to generators?

The answer is that the existing role of transmission is not to provide a service to generators, but to provide an economically-sized network for the electricity market as a whole. A TNSP is essentially established as an "infrastructure provider" rather than a service provider. Or, put another way, a TNSP only has one "customer", the electricity market, and only has service obligations to that "customer"[1].

Generators are entitled to use the network, but they have no way of knowing the level of service – in terms of delivering their output to the market – that the network will provide. So, there is an anomaly here. Generators operate in a competitive market, selling their product to retailers. Retailers expect a reliable product. But generators are unable to obtain a reliable (from their perspective) transmission service to deliver that product. The result is that, when their own generation is constrained by limitations in the transmission network, a generator must buy (in effect) from the spot market, with all the commercial risk that selling at a fixed price and buying at a variable price inevitably entails.

The level of risk for generators under this regime is proportionate to the degree of transmission congestion. The TNSPs inherited networks with very low levels of congestion, but congestion is increasing as the inherited network capacity becomes fully utilised. Risks are material now and are likely to increase further as congestion increases.

[1] Arguably, services are defined on the demand-side, so perhaps the TNSP is a service provider to this half of the market. However, from a generator perspective, the TNSP just provides infrastructure, not services.

There is nothing inevitable about this state of affairs. It is not a prerequisite, or inevitable consequence, of "open access" that a TNSP must be an infrastructure provider rather than a service provider. Indeed, the NEM designers recognised the importance to generators of receiving a defined service and made provisions in the original National Electricity Code for them to do so[2]. Unfortunately, these provisions have turned out to be ineffective, as the Issues Paper points out. In this submission, we set out an approach for reinstating this original objective and for removing the anomaly that lies at the heart of the NEM design.

<u>A TNSP has multiple conflicting roles</u>

As infrastructure provider, a TNSP is tasked with multiple roles:

- planner;
- developer;
- operator;
- information provider; and
- owner.

For clarity, these roles are described briefly below. We note that there is some separation of roles in some States, meaning that not all TNSPs perform all of these roles.

- The *planner* role is to ensure that specified network planning standards are maintained. The planner must predict when and where the network is expected to fall below the standards and to identify appropriate expansion projects to address these shortfalls. In addition, different approaches to the reliability investment test exist in the Northern States vs. the Southern States.
- The *developer* role is to design, construct and commission these projects on time and at least cost.
- The *operator* role is to operate and maintain network assets so as to efficiently maximise their availability and design capability.
- The *information provider* role is to provide to the market operator and to market participants the network information that the market requires to function effectively.
- Finally, the *owner* role is to raise capital to fund the network and to maximise the return to its shareholders.

A fundamental conflict arises between the "owner" and the other roles, since maximising profit in the context of a regulated revenue cap means minimising the costs of undertaking various roles and this will inevitably impinge on performance in these roles. Regulatory incentives attempt to resolve this conflict, and to re-align profit and performance, but this is not straightforward and in our view a number of conflicts have not been fully resolved. The most significant of these are:

- in the developer role, the regulatory incentive to minimise the cost of projects can lead instead to projects being deferred or simply ignored, particularly where planning standards are not properly defined or enforced;

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[2] *Current Rule 5.3 and 5.4A*

- in the operator role, while there are modest incentives to maximise asset availability, there are no incentives to maximise asset capability; and
- in the information provider role, a TNSP will seek to minimise the cost of information provision, leading to inadequate information being available to the market.
- in the access provider role, a TNSP is able to avoid any obligation to maintain access levels to incumbent generators due to the poor drafting inherited from the code.

We discuss these conflicts in this submission and propose approaches to resolve them. Planner and developer conflicts are considered under Q5, whilst operator and information provider conflicts are considered under Q9

<u>TNSPs are risk averse</u>

TNSPs are regulated to be low-risk businesses. Their regulated returns (WACC) are set fairly low, TNSPs must be perceived as low risk by the capital markets in order to be viable. The regulatory framework accordingly protects TNSPs from many risks that other market participants must bear: stranded asset risk, market risk, liability risk and so on. We acknowledge that there is a need to balance risk and reward and believe that the current balance for TNSPs is broadly appropriate (although we raise concerns in some specific areas in this submission).

However, in our experience, this commercial risk aversion has a tendency to lead to *cultural* risk aversion. Or perhaps, TNSPs are culturally risk averse simply for historical reasons. Either way, TNSPs tend to avoid risky options, even where the risk-return trade off is good and the risk is not borne by the TNSP anyway: except perhaps in reputational terms.

To take an example, an earlier project championed by Hazelwood, TRU Energy and Ecogen and managed by the TNSP was the option of running transformers at high ratings (above the secure “N-1” level) to avoid thermal constraints and then incorporating a fast run-back arrangement to prevent post-contingency overloading. Although the TNSP supported the project along the way, it then rejected it at the final stage due to perceived additional risks to the transformers coupled with the lack of adequate spares. Yet the resulting risk of generation being constrained is borne by the generators, not by the TNSP.

An added disincentive for the TNSP was theproject would have delayed the introduction of a much more expensive (approximately 30x) option where additional capital would become part of their revenue base with lower overall risk. This incentive misalignment is not unique.

Risk taking is intrinsic to innovation and efficiency. The transmission framework needs to encourage a reasonable risk-taking – or at least risk-neutral – culture in TNSPs. This will drive innovation and efficiency.

<u>Ineffective Inter-regional Service Provision</u>

With TNSP roles being delineated geographically, there are obvious problems of assigning responsibility and accountability for service provision at and across TNSP boundaries. These problems can lead, and have led, to poor service provision.

This issue is familiar to the AEMC: :the National Transmission Planner (NTP) was established to address it in relation to the planner role. The NTP has not long been established and so its ability to improve inter-regional planning is as yet unclear. However, the early signs are not promising.

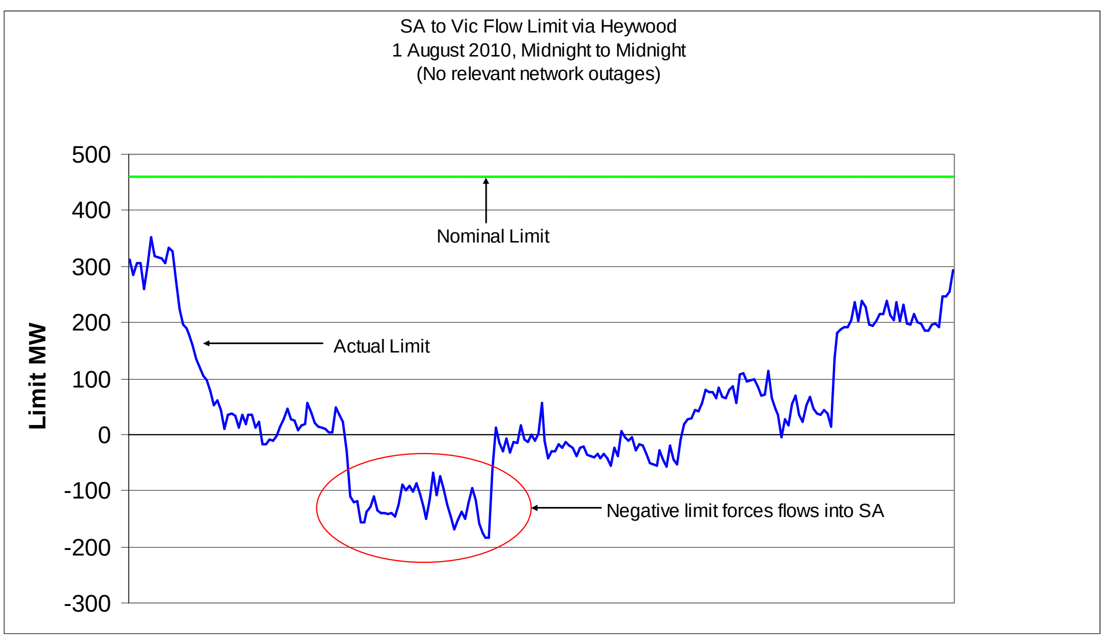
The problem seems to stem from the level at which the NTP undertakes its planning role. In transmission design, the devil is in the detail. Relatively minor and detailed projects can make a big difference to network capability. But the NTP appears to be approaching its task at a high level and so is not identifying or helping to progress these detailed projects. The solution, naturally, lies in a more detailed NTP planning process.

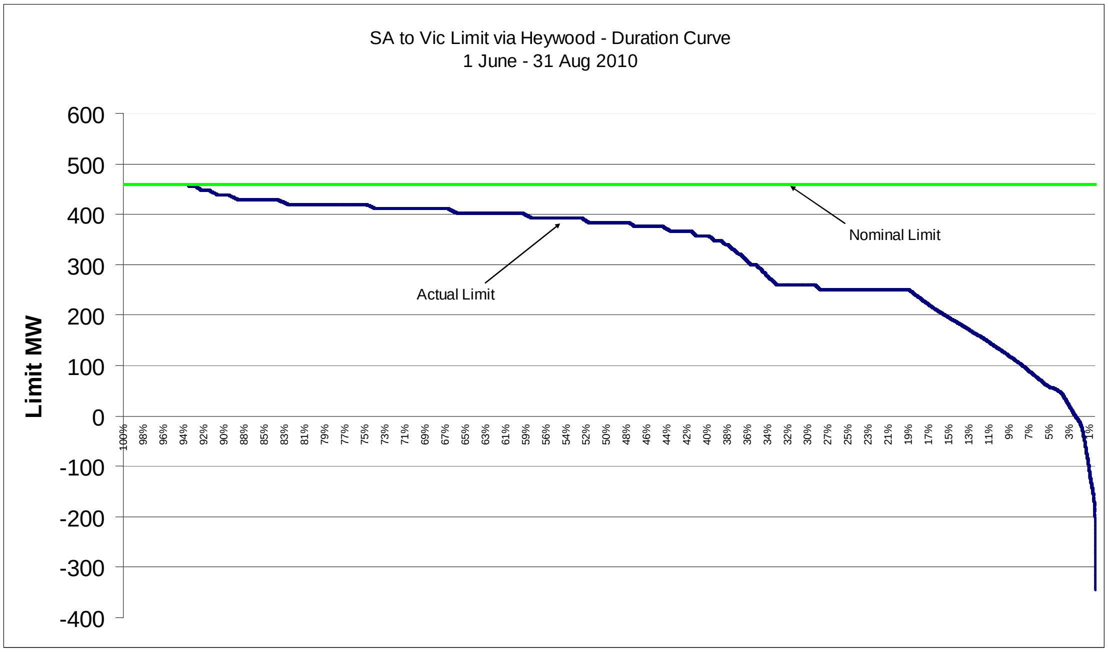
Example
The flow limit across SA to Vic Heywood interconnector is regularly reduced as a result of a constraint in the South East area of South Australia. This constraint affects the SA to Vic flow limit via Heywood, even when there are no relevant network outages.

The first graph shows the variation in the flow limit on one day, namely 1 August 2010, under conditions with no relevant network outages. The limit varies dramatically during the day, at best around 70% of the nominal rating, but at critical times reducing not just to zero but beyond, therefore, forcing a compulsory import into SA of up to 200MW.

The second graph illustrates the longer term impact of local network limits and shows a duration curve for the SA to Vic flow limit over a three month period from June to August 2010. This shows that the nominal capacity is rarely reached (about 10%) and there is a substantial period (about 30%) when the limit is about half the nominal rating or less and includes some periods (about 1%) of negative values where there is a compulsory import into SA

We note that reduced interconnector limits are often associated with extreme price events and hence with disproportionate financial risks..




SA to Vic Limit via Heywood - Duration Curve
1 June - 31 Aug 2010
Limit MW
Nominal Limit
Actual Limit

Question 3 Transmission planning

"Does the current transmission planning framework appropriately reflect the needs and intention of the market (including generators, loads and demand side response)? Will this adequately provide reliable information to TNSPs on where and when to invest, or when to defer or avoid investment, in an uncertain planning environment, or is there a case that additional market based signals might be beneficial?"

Generators currently receive *common access* to a network that is subject to an *economic planning standard*. This access does not provide generators with the transmission service they need to operate successfully and efficiently in a competitive market.

To address this shortcoming, service to generators needs to be based on a defined access level, similar to the deterministic planning standards that apply to the demand side.

The predictability of inter-regional access is currently poor, and there is no certainty that the revised planning process will overcome this.

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.

For 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, but
- 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 built[3] 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.

[3] *The project could potentially be developed as a “funded augmentation”. However, because there would be common access to that augmentation, there is a free rider problem in relation to other existing and future generators who would benefit from the augmentation without contributing to the cost.*

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/MWh and the fuel costs of generators A and B are $10/MWh and $15/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.

<u>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.</u>

<u>Deterministic Standard</u>

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

<u>Inter-regional Access</u>

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 inter-regional 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 inter-regional 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.

Question 4 Promoting efficient transmission investment

Will existing frameworks, including the recently introduced RIT-T, provide for efficient and timely investment in the shared transmission network?

TNSPs were not obliged to maintain the economic planning standard and the current NTP planning regime remains unproven.

Accountability for inter-regional planning is unclear.

Demand-side planning standards should consider absolute cost – as well as the (risk-adjusted) expected cost – of transmission failure.

A scenario-based planning should be used to ensure robust planning under uncertainty.

The RIT-T should be maintained to serve its specific purpose, but augmented by separate regimes, such as the planning criteria for generator access, as necessary to reflect any changes to planning objectives and standards.

<u>TNSPs not obliged to maintain planning standards</u>

We have interpreted the “net benefits” requirement of the RIT-T as delivering an implied “economic planning standard” for generator and inter-regional access. In an important sense this interpretation is incorrect, or at least does not provide the full picture. TNSPs are not *obliged* to invest in economic projects. Rather, TNSPs are obliged *not* to invest in *un*economic projects. As a result, the economic planning standard does not represent a minimum service level which the TNSP must always exceed, but actually represents a *maximum* level which the TNSP must *never* exceed[4].

Under Q3, we discussed the risks for generators arising due to the uncertain level of access that the economic planning standard will deliver to an individual generator. But the actual situation is much worse than this. The TNSP might not necessarily deliver this standard, in fact it might not deliver any standard. It would be within its statutory rights never to invest in any expansion of generation access, except and until this is necessary to ensure that demand-side planning standards are maintained. And, of course, a generator has no way of knowing or predicting when a TNSP might invest and no effective opportunity to influence this decision.

But, it gets worse. A TNSP is not necessarily indifferent as to whether it invests or not. It may even be encouraged – by the incentives arising from its regulatory regime –to not invest or to defer investment. This is discussed further under Q5.

The regulatory solution to this issue is straightforward. TNSPs should be mandated to maintain the economic planning standard: ie to identify and invest in all economic expansion projects[5]

The practicalities of monitoring and enforcing such an obligation are less straightforward. Whereas significant transmission-related load shedding will generally be investigated to verify whether it was caused by a failure

[4] *Except inadvertently, as a result of legacy projects or because of falling demand for network capacity*

[5] *Note that this is a much stronger requirement than that currently imposed by the LRPP: that all economic projects should be identified and tested.*

to maintain demand-side planning standards, it would be impractical to similarly investigate the generation-side every time a power station was constrained.

However, the enforcement problem becomes less problematic under a move to defined standards for generation access, since in this context the planning standard is clearer and individual generators are able to monitor the level of service they receive and compare it to their defined access level.

Accountability for Inter-regional Planning

In relation to inter-regional planning, the problem associated with the discretionary nature of the economic planning standard is conflated with the problem of collective responsibility discussed under Q2.

For inter-regional planning, our proposed obligation to maintain standards would fall on multiple parties – two or more TNSPs and perhaps the NTP also – and would become a collective rather than individual responsibility. Furthermore, it would be unreasonable to impose such an obligation if an ineffective inter-regional planning framework made meeting such an obligation impractical.

Therefore, the responsibility and accountability issues must be solved together. As we noted under Q2, this is likely to mean a more detailed role for the NTP.

Planning for Absolute Cost

When planning standards for the demand-side are developed, they typically look to equate the cost of transmission investment with the expected cost of network failure: ie the probability of failure multiplied by the cost of failure in terms of shed load and the value of customer reliability. This is the case whether the planning standard is purely economic or is a deterministic standard based on economic considerations.

That is a reasonable approach for relatively small "failure" events. However, for large-scale failures – even those with a very small probability – this may not be appropriate. Therefore, we believe that planning standards should consider the absolute cost of failure (and/or its acceptability for other policy reasons) and effectively place a cap on the size/cost of failure that is possible. This is particularly the case during extreme events, where failures that aren't correlated normally, could be highly correlated by the specific event. For example lightning, bush fires through major transmission corridor, flood impacting common infrastructure and others.

Scenario-based Planning

Historically, network planning has relied on a small number of scenarios of market growth in generation and demand.

This approach may have been adequate in the past. However, there are now substantial new uncertainties associated with prospective policies to manage and reduce future carbon emissions. Uncertainty around what policy measures will be introduced and when compounds uncertainty around how the market will respond to these policy measures. Issues that arise include:

- whether or when there will be a price on carbon and what its trajectory might be;
- where renewables required to meet the 20% RET will locate and what form they will take;

- what new technologies may emerge as a result of these changes to the policy environment: eg electric cars, smart grids and so on; and
- what further climate change policies may emerge, beyond the current policy horizon.

The need for a more extensively scenario-based planning has been recognised in the setting up of the NTP, whose planning process *is* more broadly scenario-based. Our main concern with the NTP is in how these scenarios are established. Planning scenarios should be developed and "owned" by the market as a whole, rather than being confined to TNSPs and the NTP. The process of developing these needs to be transparent and open, and it needs to involve relevant expertise from outside of the wholesale energy market.

However, our major concern is how the scenario-based NTP findings are considered by the TNSPs. TNSP expansion projects must pass the current RIT-T and it is not clear to us how scenario-driven projects would be able to do that. Clearly projects which are justified under some scenarios may not be justified in others.

Th objective is the design and application of the RIT in general, ensures that the transmission network is robust against future uncertainty and it is able to facilitate the market under a wide range of scenarios, but without catering for every possible eventuality which would lead to economic inefficiencies.

RIT should reflect revised planning standards

If planning standards for generator and inter-regional access are changed, as we propose, consequential changes to the RIT would be needed. The RIT currently refers to "reliability corrective action" in relation to investment required to meet regulated standards and the changes to the RIT would largely be a matter of wording – to ensure that this term encompassed generator-side planning standards - rather than substance.

One issue that arises is whether economic planning standards should remain in place "over the top" of the new defined access standards. This might lead to a situation, for example, where investment occurs to give a generator a higher standard than its defined access level. This may be inappropriate where a generator does not value or require the increased access. However, we have an open mind on this issue.

Question 5 Economic regulation of TNSPs

"Does the current regime for the economic regulation of transmission lead to efficient network investment? Do the incentives on TNSPs lead to appropriate investment decisions and the efficient delivery of additional network capacity?"

The regulatory incentive on a TNSP to minimise planning and development costs may conflict with efficiency objectives.

Regulatory incentives may cause TNSPs to have a bias in choosing between network and non-network solutions.

TNSPs which are government-owned, or that are affiliated with market participants, may not respond to regulatory incentives in the manner that is expected or intended.

Regulatory Incentives on a TNSP for efficient planning and development

There are multiple regulatory incentives on a TNSP, which to some extent are offsetting:

- to seek to persuade the AER of a need for capital expenditure at the time of the regulatory reset, in order to boost regulated revenue;
- to cancel or defer capital expenditure during the regulatory period, in order to maximise the difference between revenue and costs; and
- to complete capital expenditure prior to the regulatory reset in order that the new assets are rolled into the regulatory asset base and earn a regulated return.

Given these differing incentives, it is possible that "voluntary" investment on economic projects may either be encouraged or discouraged. Other things being equal, a high regulatory return (WACC) will encourage investment. However, if a TNSP considers the WACC to be low or neutral, the opposite incentives - to defer or cancel investment - might dominate.

The AER is likely to take into account historical capital expenditure against forecast when considering forecast capex for the next period. Thus, a strategy of continually under-investing against forecast may be self-defeating if the credibility of the proposed expenditure is undermined in the eyes of the AER. This credibility is particularly relevant in the case of economic investments, since a TNSP is not obliged to invest even if the economic case – in terms of the RIT – is sound.

Indeed, it is plausible that economic investments enter a vicious regulatory circle, whereby a TNSPs decides not to invest so as to maximise short-term profit, meaning that the AER does not trust future projections of spending on economic investments and disallows it, in turn meaning that economic projects have no funding, which means they are definitely not undertaken.

These considerations reinforce IPRA's concerns about the ability of economic regulation alone to ensure that appropriate generation-side and inter-regional investments are undertaken. This confirms our position discussed in Q4, that generation-side projects should be mandatory where they are required to maintain planning standards.

Bias against non-network solutions

In its planning process, a TNSP might identify a network project and a non-network project (eg embedded generation) which deliver similar net benefits as calculated under the RIT.

However, the commercial benefit and the level of risk to the TNSP of the two options may be very different. The network project would cause the TNSP to incur capital expenditure on which – from the commencement of the next regulatory period – a regulated rate of return will be provided. The cost of the non-network project would typically be passed through to users, with little or no commercial impact on the TNSP. The costs of the non-network option may vary over time even if contracted to the TNSP and there maybe a range of risk (ie fuel costs, and major equipment problems, labour issues, water, introduction of a cost of CO2 etc). However the TNSP would risk being held accountable for the non-network project outcomes.

The regulatory parameters – the WACC in particular – will cause the TNSP "owner" to prefer one project over the other: they are unlikely to be commercially neutral. Thus, this is another source of conflict between the TNSP "planner" (who would select the economically-better project) and the "owner "(who would select the commercially-better project).

Unintended Responses to Regulatory Incentives

In our analyses above, we have assumed that the TNSP will respond to regulatory incentives so as to maximise its profit. This is commercially rational for an independent TNSP. However, where the TNSP is affiliated with other market participants (as government-owned TNSPs in NSW and Queensland implicitly *are*), the commercially rational objective is likely to be an unstated objective to maximise the *group* profit: ie of the TNSP and its affiliates.

In this respect, privately-owned generators and TNSPs are in a rather different position to government-owned generators. The former will be faced with a TNSP responding as intended to the regulatory incentives, which will give rise to the concerns around generator access that are discussed under Q3.

We further observe that generators under common government ownership don't appear to as concerned about network congestion when compared to private entities.

Question 6 Network charging for generation and loads

"Is a price signal of locational network costs for generators required to promote overall market efficiency? Would there be any consequential impacts on transmission pricing arrangements for load?"

Generators should bear the network costs associated with their locational decision

Generators should not bear sunk costs associated with historical decisions

Generator charges should not seek explicitly to achieve climate change objectives

Incentives relating to power station closure are best provided by making access tradeable

Generators should not bear sunk costs

The objective of transmission charges on generators should be to encourage efficient decision-making. It is not to "tax" the generators in order to recover some of the sunk costs of the network. The efficient allocation of sunk costs (between demand-side users) has been considered and refined over successive past reviews and we believe that there is no need to re-open this issue.

Some parties may be tempted to project our "cost reflectivity" objective back into the historical period by arguing that: "the existing generators enjoy a level of access; they should pay for this access in the same way as new generators will do". There is no efficiency basis for such an argument. Existing generators cannot undo or change historical decisions, many of which were not made in a market context. In any case, such an unravelling of history would be problematic: exactly which historical network investments were made in response to which historical generator entry decisions?

A re-allocation of sunk costs would, at best, create new unnecessary risk for generators and, at worst, cause generators to take actions (eg closure) which have bear no relation to public benefit or market efficiency. Previous determination by NECA also supported this principle.

New generators to bear network costs

As discussed under Q3, there is a problem with the existing arrangements in that new entrant generators do not take account of the costs they impose on the network or on other generators (through increased congestion) when they decide where to locate new generation. We consider that the network cost issue is best addressed by levying a transmission charge on generators. The issue of shared congestion costs is considered under Q7.

The problem of allocating network costs between all generators would appear demanding, if this process were in fact necessary. But we contend that such a "global" solution is not necessary for the pupose of defining locational signals to prospective generators.

For this purpose a step-by-step process is suggested, considering each prospective generator in turn (except to the extent that questions of scale efficiency arise, and these cases could be handled along the same lines as the SENE proposal)

We do not propose to define a full solution to cost determination here, but set out some principles that should guide an effective but pragmatic solution:

- Charges should be fixed at the time of the new generation connection and not subsequently varied.
- Charges should reflect the efficient cost of the network investment required to provide the new generator with their defined access level.
- Charges should be connection-point-specific and not smeared or socialised across several connection points: eg through “zonal” pricing.

These principles are discussed below.

The first principle is needed to avoid creating new, unmanageable transmission-related risk for generators. As already discussed, these risks are already too high and are causing inefficiency. Once a generator has connected, it obviously cannot relocate in response to transmission charges (the closure decision is discussed further below). Therefore, varying the charge can serve no useful purpose.

The second principle is simply a restatement of our objective that generators should face the cost of their locational decision. If generators are able, in addition, to choose their defined access level (discussed further under Q7), then they should also face the costs associated with that choice (recognising that there may be an issue of scale-efficient development).

The third principle is needed because network costs can be node specific. For example, a shortage of transformer capacity might mean that network capacity is limited on the lower voltage side of a transmission substation but not limited on the higher voltage side a few meters away. Node-specific transmission charges will help to ensure the utilisation of the existing network is optimised and unnecessary network expansion is avoided.

We emphasise that in return for supporting a part of the cost of the shared network, the generator must also have assurance of an ongoing benefit in being protected from having additional congestion imposed by later entrants, as discussed in relation to question 7

<u>Generation Charging and Climate Change</u>

There may be a policy temptation to engineer generator charges so as to promote climate change objectives: for example, by discounting charges for new, low-carbon generation. Specifically, the TNSP should not be attempting to “pick technological winners”. This would be direct conflict with other parts of the rules (eg 3.1.4 (a) (3) avoidance of any special treatment in respect of different technologies). We believe that such a policy would be unhelpful and, in all likelihood, ineffectual. Climate change objectives are best achieved by a transparent mechanism for pricing carbon, not by artificial and unclear cross-subsidies in the transmission realm.

<u>Tradeable access would encourage efficient closure decisions</u>

The AEMC Issues Paper notes the importance of encouraging efficient locational closure decisions. We would support this as an objective, although we would note that this is not as critical as efficient connection decision: the reason being that choice of closure location is naturally limited to the location of an existing power station.

The issues paper suggests that efficient closure decisions would be encouraged by an *ongoing* transmission charge on generation, meaning that the charge becomes part of the avoidable cost of remaining open. However, this presumes that this transmission charge is likely to be an efficient signal: ie that it reasonably reflects the cost imposed on the network due to the power station remaining open.

This seems unlikely to us. The network cost may often be zero, since network assets cannot be dismantled when a power station closes. It is possible that a new power station wishes to connect at or close to the closure location, in which case closure might cause some network expansion costs to be avoided. However, it does not seem feasible for generator charges to reflect the private intentions of new generators in this way.

Our preferred approach would be for generation charges to be fixed – as described above – and for the associated defined access to be tradeable. That would mean that a prospective generator B, looking to locate close to an existing generator A, could approach generator A and offer to buy the access rights. This would encourage generator A to close – if the offer price were right. If the offer were accepted, generator B would pay generator A for its access but not be required to pay any further charges to the TNSP (assuming that the defined access levels of the two generators were the same). On the other hand, if the offer was refused, generator B could still obtain access by paying the TNSP. So, there is no “barrier to entry” to generator B, just a possibility of obtaining a discounted entry price.

The advantage of our approach is that a generator A will only be encouraged to close if there is a generator B wishing to take its place in the network. This is superior to the AEMC suggestion, where the incentive is the same whether such a generator B exists or not.

Question 7 Nature of access

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

A "base" access level must be defined before an "enhanced" level can be considered.

Defined access must be maintained throughout the life of the power station.

A mechanism is required for preserving access level and preventing subsequent new generation from unreasonably encroaching on it.

Enhanced access could be predicated on a wider range of planning conditions under which access must be provided

We believe that it would be appropriate for generators to be able to choose their level of access (discussed in Q3), so long as they bear the network costs associated with that decision (discussed in Q6). This seems to be in the spirit of the reference to "enhanced access" in Q7above.

We believe that this outcome is the clear intent of the Rules, specifically clauses 5.3 and 5.4A, but is an outcome that has not been achieved in practice. We also submit extracts from the ACCC authorisation of the NEM access regime in Appendix 1 and 2. These highlight the key concepts of the "open access" and specifically support the following principles:

- *access certainty for generators is achieved by new generators paying to augment the shared network so that other generators or customers level of access is not impacted and/or the payment of compensation should another generators access be reduced.*
- *the ACCC's objective was that in the 'open access" regime described by the ACCC any person seeking access to the network must not materially or adversely affect the levels of service and quality of supply to other network users*

Before turning to the question of enhancement, it is necessary to consider and define the "base" level of access, against which any "enhancement" must be predicated.

As discussed above, we believe that generator access needs to be defined in accordance with a deterministic planning standard: that a generator will have an access level of x MW under specified planning conditions. A higher level of "x" will represent a higher level of access. We believe it is practical and appropriate for a generator to be able to choose any level of access level x MW,

where $0 \leq x \leq$ Generator rated capacity,

and "partial access" defined as x < Generator rated capacity

We would describe the generator's choice from this menu as "elective access": and the chosen level will probably vary from generator to generator.

Elective access then sets the "base" level against which "enhanced access" options can be considered. We discuss enhanced access in the final section under this Q7, below. Before that, we provide more detail on how "elective access" would be defined and maintained.

Defined Access must be maintained

Under the current NER, a generator is entitled to pay for "enhanced access" in the sense that it can fund a network expansion project that will lead to higher access levels in the short-term. The problem is that there is no guarantee that the higher access levels will be sustained. Growth in generation or demand may lead to the new network capacity being fully utilised and access levels falling back to where they were before the generator's investment. So, the generator is paying higher charges but has no additional access certainty.

For this reason, there must be an ongoing obligation on a TNSP to maintain defined access standards through the planning process. Since the defined access levels are predicated on deterministic planning standards for generation (see Q3), the planning process through which a TNSP would do this is analogous to what it does currently to maintain demand-side deterministic planning standards. However, rather than just responding to the "organic growth" seen on the demand side, a TNSP will plan against the growth of aggregate elective access levels seen on the generation side.

Preventing Access Encroachments

To make a sustained, defined access level viable, a mechanism is required to prevent one generator improperly infringing on another generator's access. A fundamental reason for the failure of the existing "enhanced access" provisions in the NER is that there is no such mechanism established.

The concept of an improper infringement arises in the case where competing generators have chosen different levels of access, for example one generator with full access being jointly limited with another generator that has chosen partial access.

There are a number of ways that this might be done and we have no strong view on which solution is adopted so long as it achieves the objective. However, we set out one option below which we believe is attractive in that it is straightforward and that it retains a clean distinction between the access arrangements (which are managed by TNSPs pursuant to chapter 5 of the NER) and dispatch arrangements (managed by AEMO under chapters 3 and 4 of the NER).

Our proposal is as follows:

- When there is congestion that is caused or affected by a generator's output level, that generator must restrict its offered availability to its defined access level;
- At other times, there are no restrictions on offered availability (thus utilising spare capacity); and
- Compliance with the above will be monitored and enforced by the TNSP, in accordance with terms set out in generator connection agreements.

These rules will ensure that, as long as the capacity of the network exceeds defined access levels, congestion will not lead to generators being constrained below their defined access levels. However, since defined access is only predicated on a planning standard and only applies under specified planning conditions, there will be times when network capacity falls below this level. For example, if the defined access standard is predicated on “N-1” network conditions, then lower network capacity may occur under “N-2” conditions.

When network capacity is low, congestion may constrain generators below their defined access level. In this sense, access is not “firm” and generators will bear some continuing risk from congestion. However, we believe that if the defined access planning conditions are defined appropriately, this risk will be moderate and manageable, unlike the status quo.

When two or more generators are constrained below their defined access levels, the “pain” will be shared in some way that is predicated on AEMO’s dispatch and pricing arrangements.

At present, the issue of “disorderly” bidding means that “pain sharing” outcomes are volatile and uncertain. However, this is best addressed by reforming the congestion management regime (discussed under Q10) rather than through the access arrangements.

Enhanced Access

Elective access may be anywhere between default access and full access. Theoretically, elective access could be “enhanced” further by having “X” greater than power station capacity. However, since this would involve a generator paying for transmission capacity that it could never use, this would seem to have limited attraction.

The other dimension in which access might be enhanced would be by extending the planning conditions under which the defined access level is provided. For example, an “N-1” type elective access standard could be enhanced by an “N-2” access regime. So if, say, the network were in an N or N-1 condition for 80% of the time and in an N-2 condition for 18% of the time, then the enhanced access standard would provide the X MW of access for 98% of the time, compared to just 80% for base access.

Such enhanced access would have particular relevance where the network has a substantial radial element and there are few generators involved.

Question 8 Connection arrangements

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

Defined access levels would be negotiated in the connection process and specified in the connection agreement.

Defined access levels negotiated on connection

Under our proposed defined access regime, we would envisage the defined access level being negotiated and agreed between a new generator and a TNSP as part of the new connection process. Terms and conditions associated with the defined access would be incorporated into the connection agreements and would need to comply with principles and guidelines set out in the NER, similar to existing connection agreements.

Like the existing connection process, the most problematic aspect of this process is likely to be agreeing the cost/price. As discussed above, the generator charge should reflect the extra network costs associated with providing the defined access level. Unlike with the existing “shallow connection”, this “deep connection” cost can at best only be an estimate, since costs may continue to be incurred by the TNSP for the life of the access and future costs will depend upon future demand and generation conditions, which are highly uncertain.

We already have some concern about the difficulty that sometimes arises in closing the gap between the TNSP’s estimate of connection requirements and costs and the generator’s. The best mediation route is through recourse to an independent expert and we think that the NER need to change to better facilitate this.

If generators are also bearing shared network augmentation costs, the importance of rules to ensure transparency and expert mediation is all the greater. Since the deep connection is associated with expansions in the shared network, we would expect it to be non-contestable – in contrast to shallow connection – and so dispute resolution has greater relevance due to the lack of alternative suppliers.

Question 9 Network operation

"Are more fundamental reforms required to financial incentives on TNSPs to manage networks efficiently and to maximise operational network capability for the benefit of the market? Should further options for information release and transparency on network availability and outages be considered?"

Appropriate regulator incentives are needed to ensure TNSP efficiency in its Operational role.

Appropriate regulator obligations are need to ensure TNSP efficiency in its Information Provider role

Operational Role

As discussed under Q2, the multiple roles of a TNSP give rise to conflicts of interest and inefficient behaviour. In the context of network operation, the relevant conflict is between the "owner", who aims to maximise profits, and the "operator", who should incur efficient operating costs; ie on those activities where the benefit to the market exceeds the cost to the TNSP.

There are four areas of TNSP operation with significant cost and benefit implications for the market:

- planned outage scheduling
- maintenance of design ratings and performance
- management of dynamic ratings
- response to unplanned outages

In each case, the market cost will be driven by the congestion resulting from constraints that AEMO needs to place on dispatch in order to maintain network operation securely within the asset ratings. One approach to driving operational efficiency would be to make a TNSP directly responsible for congestion costs. However, such an approach is problematic for a number of reasons:

- It would impose levels of risk on TNSPs that would be inconsistent with the existing low risk, low WACC, TNSP business model;
- TNSPs would need to develop considerable expertise in the wholesale market to understand and manage these risks; and
- TNSPs would need to trade and hedge in the wholesale market and this may lead to conflicts with other TNSP roles.

Therefore, we do not support such an approach, but instead support the AER's existing approach of placing tariffed penalties on TNSP operations that impose costs on the market. We would urge the AER to continue to strengthen and deepen this approach with the objectives of:

- Extending incentives to all of the operational areas listed above; and

- Strengthening tariff penalties to bring them a little more into line with market costs

In summary, this is an area where continuing, incremental reform is required rather than a radical overhaul of the existing regulatory framework.

Information Provider Role

The conflict here is of the same nature as the operational conflict above, in that information provision costs money and yet the regulatory incentive on the “owner” is to save money. But in this case, the outcome is particularly frustrating since information provision should be relatively cheap and there is no reason for the AER not to provide an allowance to cover any reasonable, material cost.

Furthermore, the design of “incentives” seems to be relatively straightforward: simply mandate that the information is provided. However, even here, problems arise. A particular issue that we have is over the publication of network ratings information, which feeds into AEMO’s constraint formulation, the results of which are, in turn, used by market participants to anticipate the onset of any inter-regional or intra-regional congestion.

Although TNSPs do provide the information, it does appear that they make limited effort to ensure its accuracy and currency. Typically, if and when a constraint binds, a TNSP will review the relevant ratings provided and often find a way to increase them so as to better reflect the prevailing conditions (and in so doing relieve the congestion).

We observe that this is more prevalent at the times of high spot prices. However, from our observations it appears that the process of making the rating more relevant to the conditions at the time suffers from a number of deficiencies in relation to the market. In particular such actions are taken without prior notice to the market, are taken inconsistently and hence other market participants are unable to forecast their effects.

This reduces the transparency of the market and limits the accuracy of market forecasts on which participants rely. This practice thus run contrary to the effort of AEMO and AER to improve the quality of market forecasts

Generators have obligations in providing information that is important to the market – in relation to PASA and pre-dispatch – and are under strict obligations to ensure that this information is timely and accurate. Admittedly, generators may have a potential commercial incentive to mislead the market whereas TNSPs do not. Nevertheless, we see no reason why TNSPs should not have similar obligations to generators in terms of the quality of forecasts provided to the market.

Question 10 Dispatch of the market and management of congestion

Is there a need for material congestion to be more efficiently managed in the NEM?

An intra-regional congestion management regime is needed.

A complete congestion management regime will be more effective and easier to implement than a partial regime.

Any new congestion management regime needs to conform to certain high-level principles

The allocation of the risk of congestion should be considered in this review
.

Intra-regional congestion management is required

The NEM was designed to manage inter-regional congestion but not intra-regional congestion. The original NEM regions were defined so as to ensure that most congestion would occur at regional boundaries. Any sustained and material intra-regional congestion was intended to prompt a change in region definitions to make that congestion inter-regional.

Subsequently, it was decided that changing region definitions was neither practical nor sensible, and so region boundaries have been "frozen" along their current boundaries. Thus, we have arrived at a point where there is no regime to manage intra-regional congestion and no mechanism to prevent it arising.

In a technical sense, congestion must still be managed of course, through constraints that AEMO applies to the dispatch process . AEMO cannot simply allow lines to overload. However, the NEM design does not allow the market to respond efficiently or effectively to these constraints. The result, in terms of disorderly bidding and dysfunctional market outcomes, has been well-documented, including in the Issues Paper.

The issue in contention is not that the current situation is inefficient but whether the cost of the inefficiency is higher or lower than the cost of introducing a intra-regional congestion management (CM) regime.

IPRA believes there is a strong case for introducing an intra-regional CM regime. As with the access issue, the relevant measure is not the actual aggregate cost of congestion (which might be relatively low if, for example, congestion management involves dispatch choosing between power stations with similar fuel costs), but the costs – and particularly the risks – on individual generators. In this context, it is also vital to ensure that a new CM regime, while improving aggregate market efficiency, does not impose new or additional risks on individual generators.

The dynamics of loop flows and the effects of entities appearing in more than one constraint equation, mean that, under the existing arrangements, relatively minor, local congestion can be magnified and extended across multiple regions. The impact on inter-regional access (as reflected in the "firmness" of the Settlement Residue Auction, or SRA, securities) can be, and often is, dramatic. Thus, the lack of an intra-regional CM regime can lead to aggregate market impact disproportionate to the scale of the original problem.

Two examples illustrate the impact a local limitation can have. A limitation in central NSW has on a number of occasions led to counter price flow into Queensland and Victoria. The inter-regional hedging benefits that may be expected from SRA units is entirely negated under these conditions.

Similarly, a transformer limit in central Victoria (at Dederang) leads to a forced import from South Australia via Murraylink, and to consequent congestion within the South Australian network affecting local generators there.

Complete rather than partial CM regime

As discussed in the Issues Paper, the CCR final report found that “the expected transitory and localised nature of material congestion might support the case for a location-specific, time-limited implementation of congestion pricing”. As a general matter, we do not consider it appropriate to import conclusions from what was quite a narrowly-focused review (at least in the context of congestion management) into this review, which has a much wider terms of reference and which is tasked with looking much more widely for potential solutions.

However, we have some more specific concerns with the finding above. We would refer to a CM regime with such characteristics as a “partial” regime, as opposed to a “complete” regime which would encompass the entire market for all time periods. That is not to say that, under a complete regime, congestion pricing would occur across the entire market, since this would obviously be predicated on where and when congestion was actually occurring. However, under a complete regime, congestion prices (of some sort) would be established *automatically* whenever and wherever congestion arose.

In this respect, a partial CM regime cannot possibly perform any better than a complete regime. At best, it will capture and signal all of the material congestion that is occurring at any point in time, which is no more than a complete regime automatically achieves. In practice, it is liable to “miss” some of the congestion, since a partial regime will necessarily require predictive triggers to decide when and where the regime should apply, and forecasting of congestion is notoriously difficult and unreliable.

Therefore, the only possible advantage of a partial regime would lie in its cheaper or easier implementation. But we have difficulty envisaging why this would ever be the case. To run parallel pricing and settlement systems – one with congestion pricing in place and one without – must necessarily be more complex than running a single regime. Furthermore, the process of predicting congestion in order to trigger the application of the partial regime to a part of the market would incur further set-up and ongoing costs. In our view, the only possible circumstance in which a partial regime would be cheaper to implement is if one could confidently assert that a large part of the market will *never* be subject to material intra-regional congestion and so will never require an application of a new CM regime. We do not think that this is plausible.

Any partial regime would also impose uncertainty on participants in relation to when and where it would operate, and thus would inhibit hedging beyond the time horizon of the regime.

In summary, we believe that the AEMC should confine its considerations to designing and assessing complete CM regimes rather than being unnecessarily diverted by investigating the design complexities of partial regimes.

Principles for a Congestion Management Regime

At this point in the AEMC's process, IPRA considers it is premature to be putting forward possible solutions. Instead, we will confine our discussion to the appropriate principles and objectives for a future regime. We think that the appropriate principles are as follows:

- that the congestion management process or pricing depends only on actual congestion, not on predicted congestion (which essentially means that a complete regime is required, as discussed above);
- that the regime maintains or enhances the trading benefits of the regional market design in relation to hedging;
- that any settlement under the new regime is financially balanced, so that it does not draw upon or add to existing settlement flows: including existing settlement residues
- that access to the regional market for existing market participants is, to the extent practical and reasonable, preserved under the new regime.

On the first principle, as discussed above, a partial regime which relies on predictions of future congestion is likely to be less effective than a complete regime as well as being expensive to implement and operate. Furthermore, forecasting inevitably requires the exercise of judgement and discretion by the forecaster and this will lead to greater uncertainty and risk for those that are commercially affected by these forecasts. Forecasting may also create conflicts of interests with the forecaster's other roles: eg in planning timescales. In summary, a predictive approach will create a need for market participants to "model the modeller" as well as model the market.

On the second principle, there is no question that the regional design of the NEM has led to substantial trading benefits associated with the relative ease of intra-regional hedging (ie hedging of the RRP between generators and retailers in the same region) in particular. Inter-regional hedging has been more problematic due to the non-firmness of the only practical hedging instrument – the SRA security. As noted above, intra-regional congestion is making the inter-regional problem progressively worse.

To maintain the intra-regional trading benefits, a future CM solution must ensure that there continues to be a regional spot price which retailers and generators are willing and able to trade derivatives against. .

In relation to inter-regional trading, more efficient congestion management is likely to improve the firmness and predictability of inter-regional flows and this should enhance the ability to hedge inter-regionally. The new CM regime would need to ensure the continued availability of an instrument such as the SRA security which is funded by settlement residues and which provides an effective hedge against the spread between the regional spot prices.

A congestion management regime can enhance the value of SRA units by deriving a positive settlement residue from counter-price interconnector flows,.

This would eliminate any need for AEMO to clamp such counter-price flows, thus adding a further gain in efficiency of dispatch.

The third principle is needed to ensure that the new design does not create any new difficulties associated with "black hole" or "white hole" money. By preserving existing settlement flows, impacts on credit management arrangements should also be reduced.

The last principle relates to the major theme of this submission: that generators require – and should be able to obtain – certainty and continuity of access. The preservation of existing settlement rights, as far as possible, will support an ongoing hedging market, to the benefit of both suppliers and producers.

The allocation of the risk of congestion

In the current market design, the risk of financial loss due to network congestion fall almost entirely on generators. It is not clear whether this is a deliberate risk allocation decision or simply the result of failing to allocate the risk deliberately.

Perhaps because this was not a considered decision, the issue of risk allocation has not been raised as a question in the Issues Paper. "Contingency Administered Price Cap Following a Physical Trigger Event". However, this attempt was not successful.

IPRA proposes that the Commission extends this current review to consider whether the risks now imposed on generators in the event of network congestion are in all events efficient and justifiable, In particular, events that fall outside the normal expectations of network operation (known as "non-credible" contingency events) should be a particular focus in this regard.

Appendix 1 – The open access regime in the NEM

The Open Access regime in the NEM

The following summary and overview of the provisions in the rules relevant to customer and generator access shows that:

- The objective of the access provisions is to ensure that the agreed level of access for existing generators and customers will not be reduced as a consequence of the new connection; but only to the extent that all facilities or equipment associated with the power system are in service;
- for customers this is achieved by new customers paying to augment the shared network so that other generators or customers level of access is not impacted;
- The provisions for generators mirror the provisions for customers, (Except for the addition of 5.4A(h) which provides compensation for generators constrained on or off);
- access certainty for generators is achieved by new generators paying to augment the shared network so that other generators or customers level of access is not impacted and/or the payment of compensation should another generators access be reduced.

Customer clauses

The obligation to connection customers, and to charge for any augmentations necessary to maintain supply to others is contained in:

- Rule 5.1.3(a) to (c), which covers the right of access and that access is to be in under commercial terms;
- Rule 5.2.3(e) and (e1), which covers the requirement to document and maintain agreed transfer capability;
- Rule 5.2.4, which requires a connecting customer to provide forecasts as part of its application to connect;
- Rule 5.3.5(d), which requires an NSP to assess requirement for (and the costs of) all necessary augmentations to ensure that the levels of service and supply are maintained for existing customers; and
- Rule 5.3.6, which requires an offer to connect to include necessary charging detail.

For almost all customers rule 5.3.5(d), is of little significance since they have little impact on their neighbours but for large customers the cost of any deep augmentation to connect, and to maintain supply to neighbours, is currently included in the connection and TUOS charges. This can include what is termed “capital contributions”.

Generator access provisions

Generators access is defined by the following clauses:

- Rule 5.1.3(a) to (c), which covers the right of access and that access is to be in under commercial terms;
- Rule 5.2.3(e) and (e1), which covers the requirement to document and maintain agreed transfer capability;
- Rule 5.2.5, which requires a connecting generator to provide forecasts as part of its application to connect;

- Rule 5.3.5(d), which requires an NSP to assess requirement for (and the costs of) all necessary augmentations to ensure that the levels of service and supply are maintained for existing customers;
- Rule 5.3.6, which requires an offer to connect to include necessary charges and also a requirement to conform to Rule 5.4A; and
- Rule 5.4A, which:
  - o reiterates the requirement to assess changes to networks from Rule 5.3.5 (d), in f.4A (e); but
  - o which allows negotiated levels of service from forecasts and charging for the agreed capability 5.4A (f) (3), including
  - o negotiated variations from forecasts are supplemented by an ability to gain payments from the generators where the agreed transfer capability required under Rule 5.2.3(e) is reduced for another party 5.4A(h); and
  - o payment to that other party under the same clauses where the agreed transfer capability cannot be maintained.

Except for the addition of 5.4A(h) these provisions mirror the provisions for customers. They make economic sense since the cost of connection for generators can be large and when included as part of the project cost which will influence investors to locate in positions that minimise the total project cost and ensure the delivered cost of energy to consumers is considered in making investment decisions.

The access charges or the costs that are directly attributable to a generator participant's connection to a network include the cost of *connection, extension, augmentation* and *access charges* in accordance with Rule 5.4A(h).

Rule 5.4A(h) has the effect that if congestion occurs as a consequence of a new generator creating a constraint the full cost of that congestion will be allocated to the causer and not distributed to other participants. This is most likely to occur if a generator elects not to pay for augmentations.

It makes sense for large generators (and large customers) to locate where there is surplus capacity on the network or where their location would reduce constraints. This allows maximum use of the network. If additional network was to be constructed to allow connection then the newly connecting party should pay those costs since it was an additional cost solely due to them. In time it was considered that generators would be paying an appropriate proportion of all network augmentations.

Existing generators were exempt from the shared TUOS charges. This position was argued by the existing generators (and accepted by the ACCC) on the basis that:

- the level of access available to generators was constructed at the time the generator was constructed and it was difficult to determine a fair share of costs now. Generators that had been sold to private parties had included their purchase price the level of access that was defined in the Code; and
- no economic advantage would arise from applying a transmission charge to incumbent generators, which is a locational signal, to generators that had already been constructed since moving them was impossible.

At the time of market start the shared TUOS charge (a sunk cost) should be treated as a large fixed amount that should be allocated in an economically efficient way, that is with least distortion, and that implied as need to allocate the cost to the final consumers as far as possible

In negotiating access the Rules provide for:

- transmission capacity to be built and the shared network to be augmented to a level agreed in the connection agreement so that other generators agreed level of access will not be reduced as a consequence of the new connection (only to the extent that all facilities or equipment associated with the power system are in service) ; and
- a right to compensation where a generator's output is reduced in the presence of a network constraint, due to the output of another generator or on the occasions when it was constrained off due to a failure of the NSP to meet the minimum standards of performance set by the Rules.

(The economic effect of these two provisions is essentially the same however providing compensation has the potential to apply in a broader range of circumstances than augmenting the network and therefore has been described as being "stronger".)

The Rules require the TNSP to provide the cost of *connection* and *extension assets* as well as *augmentation* and *access charges* in accordance with Rule 5.4A(h), and for generators to pay them. If a new generator does not pay for *connection* and *extension assets* it is unlikely that it would be connected to the network, however in practice it appears that at least in some cases, TNSP's see no obligation to include the cost of *augmentation* and *access charges in connection agreements*. The reasons for this are not clear.

Possible reasons for neither TNSP's nor new entrants to include *augmentation* and or *access charges* in connection agreements may be:

- It is commonly accepted view that in an open access regime generators have no access rights,
- New entrants wish to avoid the additional costs and don't understand the consequences,
- TNSP's have been able to connect new entrants because there has been surplus transmission capacity and there has be no need to consider *augmentation* and or *access charges* in negotiating connection agreements,
- TNSP's have been able to avoid congestion by funding transmission upgrades by other means,
- Calculating the access charges or compensation payments based on market outcomes is outside the TNSP's area of expertise.

Appendix 2 – NEM access code Decision (16 September 1998)

Appendix 2: Analysis of the intent of the access of the NEM "open access" regime as described in the "NEM access code - Decision (16 September 1998)" with respect to generator access.

This analysis in our view;

- demonstrates that there is at least consistency between the Rules as interpreted in this submission and the ACCC access code decision and
- the ACCC's objective was that in the 'open access" regime described by the ACCC any person seeking access to the network must not materially or adversely affect the levels of service and quality of supply to other network users

The following is a review of the relevant extracts from the **NEM access code -** Decision which describes the NER 'open access regime'.

Although the Rules may not suffer from any of the particular kinds of problems for which it is valid to turn to extrinsic material, this information has been provided because it appears that their may be different views as to the collective effect of the Rules.

The ACCC considered that the access provisions in the Rules are consistent with the Commissions objectives and in particular that incumbent generators are entitled to have their access protected

4.1 Overview of connection and use of system arrangements

The following statements appear in the introductory section:

"The code aims to create a workable, non-discriminatory right of access to the physical 'natural monopoly' network which enables users to participate in the competitive electricity market."[6]

"These procedures are governed by a set of connection principles, objectives and obligations (see Box 4.1). In bringing these procedures together in the access code, the applicant (sub. p. 216) argued that:

> It needs to be recognised that arrangements and procedures for connection to transmission and distribution networks have existed for many years but these differ between jurisdictions and between Network Service Providers. One objective of these provisions is to provide a common set of procedures for connection to simplify entry for parties seeking access."[7]

and

> "Connection to a network at the wholesale level typically will be covered by a connection agreement between an NSP (transmitter or distributor), a generator or a customer (eg a mine or industrial plant). Provided other users are not adversely affected, the connection agreement may override code provisions and must include:
>
> - the legal and financial terms and conditions of the connection;

[6] NEM access code - Decision (16 September 1998) Page 75
[7] ibid Page 75

- service standards for ongoing use of the network;
- technical specifications for the type of connection involved and its operation; and
- details on payment for connection and network service”.[8]

It is clear then from the summary that creating a workable, non-discriminatory right of access to the physical 'natural monopoly' network is not inconsistent with ensuring existing users are not adversely affected.

Also it was noted that that the intent was to provide a standardised set of that arrangements and procedures for connection to transmission and distribution networks that replicate those that have existed for many years, . Replicating these historical arrangements would also mean an incumbent’s access would be protected.

4.2 Connection negotiation procedures

4.2.1 Issue for the Commission

In accepting the Code the major issues that the Commission assessment focused on were;

- The impact on barriers to entry, i.e. ensuring that the Code did not create a barrier to entry, and
- Spill over effects, i.e. protecting the legitimate business interests of incumbents, (both network owners and users), from the impact of new entrants

This is demonstrated from the following statements”

> ‘The Commission’s assessment of the access code’s connection arrangements focuses on their likely impact on entry barriers and spillover effects. The assessment criteria of particular importance addresses the issue of how the connection arrangements:
>
> - promote the public interest by not unnecessarily adding to entry barriers which would reduce contestability in other markets;
> - protect the legitimate business interests of:
>   - the existing network owners and users from potential spillover effects from the operation of new connections; and
>   - new connectors from potential spillover effects from the operations of existing network owners and users.”[9]
>
> “In terms of the network connection procedures, the Commission has focussed on whether the connection procedures create an entry barrier and, if so, whether these entry barriers are non-discriminatory between existing, new and potential entrants and between differing technologies.”[10]

In its assessment the Commission did not find that the access arrangements created a barrier to entry or were discriminatory and therefore accepted the access arrangements proposed by NECA, the applicant.

4.2.2 What the applicant says.

The following extracts demonstrate that NECA, (the applicant), also noted that the a major principle in formulating the Code was that connection arrangements were not to materially or adversely affect the level of service to others, but new entrants could obtain access at defined (fair and reasonable) prices which accurately reflect the cost of providing the

[8] ibid Page 76
[9] ibid Page 76
[10] ibid Page 77

necessary assets to allow connection at the specified capacity and level of performance. This means that incumbent generators have their access protected from degradation by new entrants and new entrants would pay for the assets required so that others level of service would not be materially or adversely affected.

In the decision the Commission noted that"

"The applicant indicated that (sub. p. 216):

> The major principle of the connection requirements provisions is that a party is to be provided physical access to a transmission or distribution network on a fair and reasonable basis provided that the connection arrangements do not materially or adversely affect the levels of service and quality of supply to other network users."[11]

"The applicant stated (sub. p. 220) the connection requirements are based on the principle of commercial negotiation and are synonymous with the concept of 'light handed regulation' as:

- NSPs and parties seeking access must negotiate a connection agreement that:
    - meets the needs of the connection applicant; and
    - does not adversely or materially affect the levels of service and quality of supply received by other network users."[12]

Clause 5.3.5d is consistent with this argument and the following position.

> "In addition, the applicant (sub. p. 221) argued that these arrangements give participants full control over network service options, with scope to make appropriate trade-offs between cost and the performance and reliability of the network service provided, for instance: New entrants can seek access to a transmission or distribution network and will be able to obtain access at defined (fair and reasonable) prices which accurately reflect the cost of providing the necessary assets to allow connection at the specified capacity and level of performance."[13]

The ACCC acknowledged NECA's intention that the compensation provisions in the Code (clause 5.5f now 5.4Ah) provided generators with "firm access", and NSPs are also required to negotiate in good faith to in relation to augmentations and other "firm access" agreements, which could also be based on the compensation provisions in 5.4Ah.

> 'The applicant also argued (sub. pp. 158–9) that the code provides the option of 'firm access' arrangements for generators. NSPs are to negotiate in good faith to provide compensation in the event that a generator is constrained-off because the level of service and capability of the network is not consistent with the terms of the connection agreement.[14]

They are also required to provide adequate information to support negotiations and use best endeavours to meet each generator's request, consistent with good industry practice and related decisions on augmentations and other firm access agreements. NSPs can also negotiate similar arrangements with customers and other NSPs but they are not obliged to do this:

> A major concern for generators arises from the possibility that such an outage could coincide with a high pool price incident in the energy sub-market. This would expose

[11] ibid Page 77
[12] ibid Page 80 & 81
[13] ibid Page 81
[14] ibid Page 82

> generators with contracts for differences in the energy sub-market with very high difference payments.
>
> The compensation provisions in clause 5.5(f) are to enable the generator and the Network Service Provider to come to an appropriate risk sharing arrangement...[15]

Neither the ACCC nor NECA distinguished between different levels of "firm access" discussed in the decision; however the discussion demonstrates that that there could be different levels of "firm access". The Code provisions provide one level of firm access under 5.3.5d and 5.5f (i.e. 5.4Ah). That the term "firm access" can encompass a range of different levels or conditions of access is evident in the discussion below on the "Commissions considerations".

4.2.4 The consultant's views

These consultants' views as elaborated below are consistent with the applicants and the Commissions objectives and are embodied in the Code.

> "Nevertheless, Western Power argued that the code's connection inquiry and offer process would be improved if:
>
> - existing agreements were honoured when affected by someone else's new connection, unless the parties agree otherwise or the change is to ensure the safety, quality and reliability of supply;
> - any new agreement should not, as far as possible, impose a barrier to entry to future participants;"[16]

4.2.5 The Commission's considerations

Firm access

> "The Commission is aware that firm access is much debated and the current code provisions are the latest of several versions. In addition there has been a profound change in the commercial relationship between generators and transmission networks, as well as others in the industry, as a result of structural separation and privatisation along with the wholesale markets and access arrangements. Previously, firm access arrangements were determined by administrative decisions, often internalised in a single organisation or at least in a public sector framework."

The Commission noted that NSPs were not obliged to provide firm access in every case however the Commission did note that the Code contained some "firm access" provisions (it would appear that the access provisions in the Code generally replicate in an economic sense at least the access provisions previously determined by administrative decisions, i.e. the central planner). The Commission described the "firm access" provisions generally as follows;

> "Although NSPs are not obliged to provide firm access in every case, the code includes a set of obligations in terms of negotiation, information and compensation arrangements. Similarly, generators are limited to their maximum power input and any arrangements must account for its impact on firm access for other generators."

The provisions to which the Commission was referring are those in chapter 5 of the Rules that define generator access provisions.

Strengthening of the Firm Access Provisions

[15] ibid Page 82
[16] ibid Page 84 & 85

During the consultation process on the application by NECA, generators sought a significant strengthening of the firm access provisions in clause 5.5 (now 5.4A). The Commission summarised the generators position as follows;

> "For instance, at the pre-decision conference and in subsequent submissions8, generators argued for a significant strengthening of the firm access provisions in clause 5.5. They requested that NSPs be obliged under the code to negotiate and offer firm access hedge arrangements with compensation whenever generators are constrained-off the network. They argue that, under the present provisions, NSPs presently negotiate from a monopoly position and thus have no incentive to bear extra risk of network constraints and the adverse impact these constraints can have on access to favourable pool prices. The incumbent generators argue that NSPs should offer a choice of access arrangements including, but not restricted to, firm access. They also argue that obliging NSPs to offer firm access would be the most efficient allocation of network risks to the party most able to bear the risks and would reinforce locational pricing on different parts of the network, thus removing uncertainty for new generators connecting to the network."[17]

The Commission noted that the Code supported negotiations between NSPs and generators to provide generators with a "firmer" level of access than that defined as a minimum level of service.

> "Improved cash flow provides a major incentive for both generators and NSPs to bargain firm access. Generators are either compensated when constrained-off or are able to bid unconstrained (because of network improvements) when spot prices are favourable; and NSPs derive revenue from the sale of firm access rights which can partly fund those network improvements. <u>Consistent with these incentives, the code provides for maximum prices for a defined (minimum) network service. It also envisages that participants can negotiate discounts for the defined service or can negotiate for an improved level of service but at a higher price.</u> In this context it should be remembered that generators pay little in the way of TUOS charges."[18]

The Commission further stated;

> "However, firm access and insurance arrangements will make the relationships between generators and NSPs more complex due to the sharing of risk. Consequently, the Commission believes that while the code is largely neutral on firm access arrangements, the code includes sufficient flexibility for generators and NSPs to negotiate access arrangements (including firm access) which is in the commercial interests of both parties. Nevertheless, if the generators' concerns are realised, and the NSPs refuse to negotiate terms and conditions, then at that stage it may be appropriate for the Code Change Panel to consider alterations to the code which provide NSPs with additional incentives or obligations to provide firm access arrangements."[19]

The Commission declined to address the generators requests for a significant strengthening of the firm access provisions in clause 5.5 (now 5.4A), and instead referred the issue to NECA.

> "At an appropriate time after the commencement of the market, the national Electricity Code Administrator should review the arrangements for firm access so the

[17] NEM access code - Decision (16 September 1998) Page 91
[18] ibid Page 89
[19] ibid Page 90

> code change processes can consider any amendments required to introduce <u>further incentives and/or obligations regarding the provision of firm access."</u>

This review therefore was to be in relation to "further" incentives and/or obligations regarding the provision of "firm access", i.e. in relation to the feasibility of and options for increasing the firmness of the access provisions already in the Code or Rules.

The fact that the Commission did not support the "further firm access" provisions does negate the firm access provisions in the Code/Rules.