Major Energy Users Inc.

Australian Government Productivity Commission

Electricity Network Regulation

Comments on the Issues Paper

Submission by

The Major Energy Users Inc

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Executive Summary

The Major Energy Users Inc (MEU) welcomes the opportunity to provide views on the Productivity Commission's review on benchmarking and interconnectors.

The MEU is very concerned with the causes of the failure of energy policy and development in recent years. Unbalanced network Rules, poor regulatory outcomes, and extensive government interventions in energy markets at Federal and State levels, have dealt a blow to Australia's declining international competitiveness in electricity pricing since 2007, with Australian prices poised to escalate over the next few years.

Poor regulation has delivered massive and inefficient investments in electricity networks. And the plethora of clean energy and energy efficiency schemes (there are nearly 300 such schemes nationally) that are in place, have added massively to the cost of doing business in Australia. Continuation of such schemes in the light of the introduction of the carbon tax is a poor public policy outcome for the economy.

Against the above background, major energy users in Australia can only hope for a dramatic improvement in the energy policy framework, especially with the required leadership at governmental levels. There is also the prospect that proposed Rule changes made by the AER to rebalance the network Rules may emerge.

In the meantime, there is a need for the range of tools to strengthen the capacity for efficient regulation of monopoly network businesses to be available, such as benchmarking. The MEU considers that benchmarking is the best tool available to regulators to ensure that the efficient frontier is approached in setting future allowances for capex, opex and WACC.

In relation to interconnectors, the MEU considers that there is a need to reflect the cost to consumers of outcomes when there is inadequate interconnection. It is unacceptable to rely on a net market benefit to assess the benefit of interconnection when the costs of the interconnection are borne exclusively by consumers.

1. Introduction

The Major Energy Users Inc (MEU) welcomes the opportunity to provide views on the PC's Issues Paper addressing Electricity Network Regulation, specifically addressing the use of benchmarking of monopoly network service providers and the dearth of augmentation of inter-regional connections since the NEM commenced.

1.1 About the MEU

The Major Energy Users Inc (MEU) represents some 20 large energy using companies across the NEM and in Western Australia and the Northern Territory. Member companies are drawn from the following industries:

- Iron and steel
- Cement
- Paper, pulp and cardboard
- Aluminium
- Processed minerals
- Fertilizers and mining explosives
- Tourism accommodation
- Mining

MEU members have a major presence in regional centres throughout Australia, e.g. Western Sydney, Newcastle, Gladstone, Port Kembla, Mount Gambier, Whyalla, Westernport, Geelong, Launceston, Port Pirie, Kwinana and Darwin.

The articles of the MEU require it to focus on the cost, quality, reliability and sustainability of energy supplies essential for the continuing operations of the members who have invested $ billions to establish and maintain their facilities.

Because the MEU members in many cases have their major manufacturing operations located in regional centres, the members require the MEU to ensure that its comments also reflect the needs of the many small businesses that depend on the existence of large manufacturing operations, and the many residential electricity consumers that make up the members' workforces and contractors.

1.2 The MEU view of the energy markets as a whole

The original concepts behind the NEM (as propounded by Professor Hilmer) were that disaggregation of the vertically integrated government owned electricity providers would result in increased efficiencies, prevent the extraction of monopoly rents in sectors that are natural monopolies, and through robust competition in contestable sectors, deliver efficient services, when coupled with efficient economic regulation. In the monopoly sector, the disaggregation was

intended to allow consumers to be more involved in managing their demand for electricity supplies and to minimise their costs through greater transparency.

Despite the initial moves in the electricity market to foster robust competition by diversifying ownership, the Australian electricity industry has, in fact, become more concentrated, along with re-aggregation between retailers and generators[1]. During the 'reform period', this process of concentration has resulted in fewer retailers and three dominant vertically integrated "gentailer" businesses dealing in multi-fuels, including wind, solar and other renewable energy sources. Investments in new generation have largely been undertaken by these vertically integrated businesses who have also procured many generation assets made available for sale[2]. There has been little interest by merchant/independent generators building new generation assets since the early period in the development of the NEM.

These outcomes (ie fewer independent generators and a very few very large energy retailers which are also the major providers of new generation) would suggest that the barriers to entry are higher now in both retail and generator sectors since the disaggregation process.

The MEU has analysed the degree of competition in the NEM based on calculations of the Herfindahl Hirschman Index (HHI), which is an indicator used to provide a helicopter view of market competition. The revealed trends are not encouraging.

For example, the HHI for retail in the NEM (now that EnergyAustralia, Integral Energy and Country Energy retail functions have been acquired by Origin Energy and TRUenergy) indicates that the electricity retail market is classified as "highly concentrated".

Generation is classified as "moderately concentrated" on a NEM wide basis, but in each region of the NEM, generation is "highly concentrated" in all regions but Victoria, where it is classed as "moderately concentrated".

Of interest is that the HHI for generation in the NEM states prior to disaggregation indicates that generation only just reached the classification of "highly concentrated", and the market concentration of retail was of a similar order. This indicates that whilst the process for disaggregation of generation has achieved some small reduction in generation market concentration, the outcome for retail shows that there has been an increase in market concentration on a NEM wide basis.

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[1] For example, it is interesting to note that Origin Energy and AGL Energy are now larger businesses than any of the state owned entities that were the initial focus of the disaggregation

[2] These include the "gentrader" assets sold recently in NSW

Quantitative analysis, such as this, reinforces the intuitive views that the NEM has achieved only small gains in generation competition (although there are marked regional differences) but retail concentration has increased markedly in recent years. Yet, despite such quantitative analysis demonstrating the reverse, there has been a curious mantra perpetuated by some that competition has increased as a result of the disaggregation of the government owned vertically integrated supply businesses.

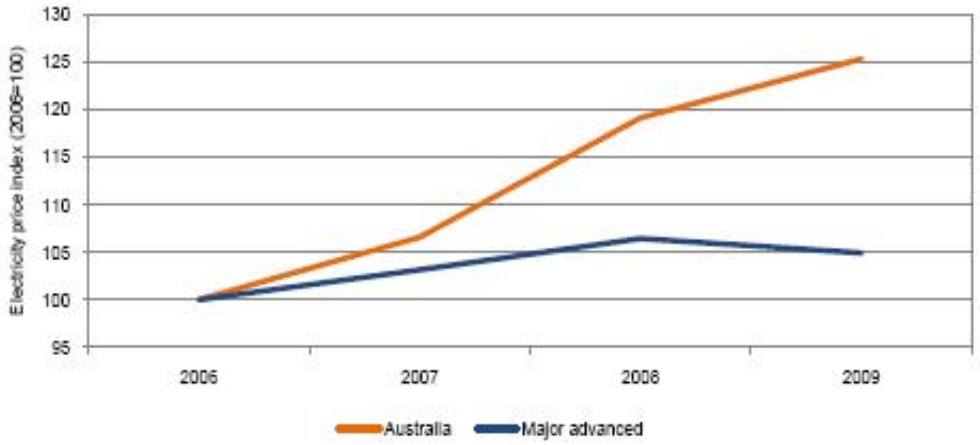
Such minimal reductions in generation competition with reduced retail competition provide, prima facie, a view that there are significant barriers to entry of new generation and even more so for new entrant retailers.

The NEM design is based on providing strong incentives for the supply side to provide a vibrant and responsive electricity supply. If incentives are inappropriate and over-incentivised investments are made in transmission (and distribution) networks – as have been the case under the existing Rules – users of energy will face significantly higher but arguably unnecessary costs (and hence adversely affect downstream investments). Even more importantly the Australian economy will be incurring large dead weight losses.

But in delivering a reliable electricity market (as has been the case), the incentives provided to supply side participants have resulted in a number of detrimental outcomes, including:

- The sharply increasing cost of electricity as identified by Garnaut[3] in his update #8 in both relative (figure 1) and actual (figure 2) terms[4]

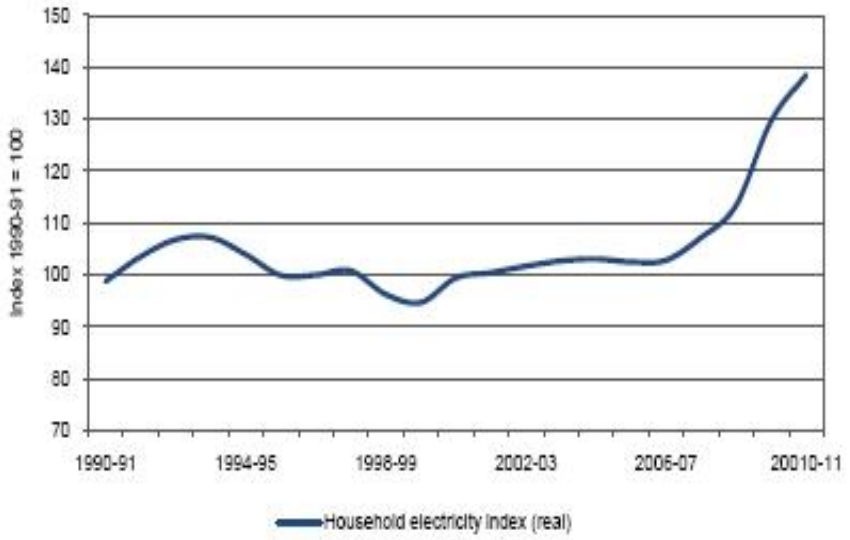
Figure 1: Real electricity prices in Australia and the seven major advanced economies, 2006 to 2009, index in US dollars



Source: IEA 2009, OECD 2010.

[3] Garnaut: Climate Change Review Update 2011 Transforming the electricity sector
[4] ibid pages 7 and 8

Figure 2: Real household electricity price movements
(constant 100 would mean electricity prices rising at same rate as other prices)



Source: Australian Bureau of Statistics, Consumer price index for electricity (Category 6401.0).

- Electricity consumption in recent years has flattened to the extent that in some regions electricity consumption is falling, such as in NSW. This fall in NSW might be a result of the massively increasing costs of electricity in that region.
- The apparent use by state governments to use their electricity assets to extract indirect taxation from electricity consumers through increased dividends
- The separation of the setting of network reliability performance standards (set by governments) from the costs involved (set by the regulator)
- Increased consumer costs caused by the continually increasing:
    - Volatility and risks in the market resulting in increased costs for consumers
    - Transaction and prudential costs
- The loss of the benefits of competition by concentration and raising of barriers to new entrants by:
    - A reducing number of participants due to amalgamation and sale of government owned entities to existing market participants
    - The re-aggregation of generation and retailing and the emergence of the “gentailer” model of market participant
    - The ability of generators to exercise market power

Overall, whilst the supply side incentives have delivered a reliable electricity supply system, there have been some significant negative outcomes to the approach taken.

Consumers are already seeing electricity costs rising very quickly, arising from a range of causes, such as:

- Generator market power (e.g the AER has identified that Torrens Island Power Station in SA has market power when regional demand exceeds 2500 MW) and a significant contributor to this ability to exercise market power is that inter-regional connection is too weak
- Steeply rising transmission and distribution network prices – on average these will rise in real terms by ~50% over the next five years[5]
- The electricity market exhibits excessive volatility in spot electricity prices, and as a result retailers are including in retail price offerings, large risk premiums which are causing significant retail contract price increases
- Implementation of the proposed carbon emission tax
- Implementation of the 20% renewable electricity target (eRET)
- The indirect costs caused by the need to augment networks to meet the carbon tax and eRET requirements
- Myriad other Federal and State Government renewable energy and climate change programs and 'initiatives', such as feed-in tariff schemes, climate change levies, energy efficiency programs, etc

Overall, there is a general expectation that electricity supply costs will rise in real terms by 100% or more over the next few years as a result of these changes, a significant proportion of which is driven by myriad government interventions in a supposedly competitive market. This is having a 'chilling' effect on downstream investments and creating an environment where ability to pay for electricity supplies is becoming a major issue for all consumers, ranging from large industrials facing international competition to small consumers, especially in the lowest income quintiles.

There are many fundamental flaws in the current transmission and distribution revenue and pricing framework and these are likely to be accentuated by the introduction of governmental policy interventions onto what is supposed to be a competitive independent market. The impositions by government of the renewable energy targets and nearly 300 energy efficiency schemes around Australia have also had indirect impacts in addition to the headline costs of the schemes. For example, the introduction of intermittent generation (such as wind and solar) require considerable increases to the electricity networks to deliver large volumes of electricity for short periods of time. Unfortunately, many of the imposts and regulations applied to the electricity supply arrangements have added to the overall cost of doing business in Australia.

[5] Weighted annualised average increases for the three years 2010, 2011 and 1012 shown in the table in appendix 1 gives an increase of ~40%

1.3 A general view on the monopoly elements of the electricity market

Whilst the retail and generation elements of the electricity market are seen as contestable, the market operation and transport elements of the market are run as monopolies for sensible reasons. These monopoly elements are controlled by regulation to ensure the costs imposed on consumers for those services are efficient.

MEU member companies have been significantly adversely affected by the current round of economic regulatory reviews of transmission and distribution network businesses, and they have seen electricity network charges rising by between 30% and 50% in 2010 in NSW alone, with similar orders of magnitude increases being seen in Queensland and South Australia. The MEU sees further substantial increases in prospect for energy transport assets unless there are significant changes to the current unbalanced network Rules and a dramatic rationalisation of the plethora of government clean energy and energy efficiency schemes.

With significant investments required in renewable and lower carbon generation and new energy transmission networks in prospect, arising from government imposed climate change policies, MEU members are very concerned that these be undertaken efficiently, in a timely manner, and at locations where they are needed.

The significant changes to the Rules underpinning the regulatory approach to setting network revenues made in 2006 and 2007 changed from a more balanced approach to one which is heavily biased to incentivising investment in the networks. This change has been seen in the most recent round of regulatory decisions. The massive increase in incentives has been one of the reasons for the recent blow out in network prices that was noted by Garnaut (in his update #8) and the reports by the NSW government and IPART on the same issue.

The changes made in 2006 (transmission) and 2007 (distribution) also reduced the emphasis on “competition by comparison” used by regulators under the Electricity Code, to one of regulators having to accept proposals from network owners if the proposals were within “reasonable bounds”. This change in emphasis from a “consider/decide” model used previously (where the regulator determined what an efficient revenue allowance was) to one of “propose/respond” where the regulator is more constrained in imposing what it considers is the efficient revenue allowance. Essentially, the change places the onus on the regulator to prove where the applicant is incorrect whereas good practice should be where the applicant has to prove that its claims are correct and appropriate. This is because the applicant has a much deeper understanding and access to costings (through running its own business) than the regulator.

The current approach to regulation of energy assets is by the use of the "building block" approach where the monopoly proposes a build up of its costs for each element of the network operations. The main elements are return on capital, return of capital, capital investment (capex) and operations and maintenance expense (opex). Each of these groups are broken down into subgroups and costs are developed by the applicant. This approach is often referred to as a "bottom up" approach.

The regulator reviews each subgroup and then notes what changes it considers are necessary to provide an efficient cost. Regulators use benchmarking (competition by comparison) to highlight where there appears to be inconsistency in what an applicant seeks and the onus should be on the applicant to show why there should be an inconsistency. There is a strong asymmetry of information in favour of the applicant as the regulator does not have the time or the tools to investigate each cost of each subgroup. To overcome this, the regulator uses two basic tools – the first is to carry out an in-depth review of a selection of subgroup elements and then to draw a conclusion across all elements in the subgroup, and the second is to apply competition by comparison analysis or benchmarking against the previous performance by the entity and against performance of similar entities. Essentially, this second tool applies the principle of competition by comparison.

Competition by comparison can be readily applied to the development of the weighted cost of capital and to opex. It is less straight forward to apply competition by comparison to entities where the capex requirement is typically "lumpy" although this "lumpiness" can be smoothed by analysis over an extended period.

Experience of consumers over the latest round of regulatory decisions in the energy sector has exhibited little "competition by comparison" applied, and where it has been applied, this has been in using historic opex of the entity as a starting point for setting future opex. Even in this area, many applicants have proposed that some subgroups within the opex allowance should be set on a "bottom up" approach without reference to past performance. Under the propose/respond approach that underpins the current Rules, the regulator is essentially constrained to follow this lead and not use past performance as its basis for assessments of future opex costs..

1.4 The inherent flaw in the building block approach

There is a fundamental issue with capex that must be addressed. This flaw provides an inherent incentive to all regulated firms to over-invest in their assets. Because of this, it is essential that there be introduced benchmarking of capex to ensure that competitive pressures are placed on regulated energy businesses in respect of capex.

Under the building block approach to setting allowed revenues, the profit element of the firm is embedded in the weighted average cost of capital (WACC) – the return on equity calculation includes the market risk premium which is calculated from the all ordinaries accumulation index which sums the capital growth of the share with the dividend paid to the shareholder.

As the regulator develops the allowed revenue from the product of the regulated asset value and the WACC[6], if the regulated firm seeks to improve its profitability it must increase the regulatory asset base. Thus there is an implicit incentive to increase the asset base by increasing the amount of capex it is allowed.

This incentive is further strengthened because under the new Rules, all capex, including capex overspending, is automatically rolled into the asset base. As a result, consumers have seen in the recent round of regulatory decisions, regulated firms (especially those government owned where capital is more readily available) have tended to overspend their capex allowances especially over the last 1-2 years of the regulatory period, thereby increasing the asset base for long term profitability but with minimal impact on short term profitability.

That the embedded incentive is not managed by any comparative assessment (such as benchmarking, improved governance arrangements, or ex post reviews of capex overspending) is very concerning to consumers as there is little incentive to attain the efficient frontier and many incentives not to do so.

[6] Depreciation and opex are included in the allowed revenue as cost recovery elements.

2. The PC approach to the review

This section addresses elements of the review following the PC structure of the Issues Paper

2.1 The framework of the review

In the Issues Paper the PC appears to have taken a view that benchmarking is not an essential element of the regulation of networks, although it might be a useful adjunct if it can be shown to improve the regulatory process.

However, this assumption is completely false. The underlying assumption flies in the face of the need to impose competition to ensure that the efficient level of performance has been achieved. It is therefore only competition by comparison (a second best alternative to real competition) that must be applied to monopolies because, by definition, they are not subject to competition.

This point is made succinctly by Mountain and Littlechild[7] where they comment (pages 10-12)

> "Ofgem has consistently employed benchmarking to compare companies and thereby set challenging price control targets as a means to encourage greater efficiency and distribute the benefits to customers. ...
>
> Benchmarking has had a large role in establishing operating expenditure allowances in all the GB distribution price control reviews. Relatively simple comparisons were the basis of the 1994 price control proposals. A corrected ordinary least squares regression was developed in the 1999 price control review to establish opex allowances. This was refined and developed further in the 2004 price control review. In the price control review currently underway, Ofgem (2009a) noted that:
>
> > *"Our benchmarking results form an important input into our assessment of the DNOs' efficiency and highlight where there are potential issues in the DNO (distribution network operator) forecasts …".*
>
> Ofgem has retained an academic advisor to assist in the development of benchmarking methodologies, and has commissioned a variety of benchmarking studies. …
>
> By contrast, benchmarking in Australia has been supported in principle but has become somewhat inconsequential in practice. It was raised in the initial

[7] "Comparing electricity distribution network costs and revenues in New South Wales and Great Britain", University of Cambridge EPRG Working Paper 0930

> discussions of the regulation of distributors in NSW, and in the mid-1990s benchmarking studies of NSW distributors suggested underperformance by these distributors. In the context of the first distribution price control review London Economics undertook a benchmarking study for IPART, which concluded that NSW distributors were inefficient compared to the 200 other distributors in the dataset (IPART 1999). …
>
> Regulated network businesses argued against benchmarking in the debate that preceded the finalisation of the relevant chapters of the National Electricity Rules …[although] …[t] he National Electricity Rules nevertheless require that the AER have regard to benchmarks of the operating and capital expenditure of an efficient distributor. …
>
> In the absence of systematic benchmarking to establish efficient levels of expenditure, the Australian Energy Regulator, and the ACCC before it, relied heavily on "bottom-up" reviews of distribution business expenditure proposals by consulting engineers.

This reliance on bottom-up analysis is beset by two main problems. The first is that bottom up analysis does not address the ability to pay question and secondly, the asymmetry of information places considerable power in the hands of the regulated firm compared to that of the regulator or its adviser.

2.1.1 Ability to pay

Regulation is intended to impose a competitive outcome on a monopoly. The need to recognise competition is that an essential element of competition is the need for providers to recognise the ability of the customer to pay for the product or service. If the price is too high then the product or service will not be accessed, but in the case of a monopoly provider of an essential service (such as electricity transport), the customer has no choice but to pay whatever the price is charged for the service.

In a firm where there is competition for its product or service, traditionally junior and middle management will deliver to senior management a "wish list" of opex and capex items at budget time. This is then reviewed by senior management and a cap set on both capex and opex to reflect both the ability to source capital and the ability to compete in the market when all costs are included in the price of the product to be sold.

Whilst privately owned NSPs experience the constraint on accessing capital to some extent, they do not have the same constraint on opex as the regulator sets the allowable revenue on the basis of what is considered acceptable rather than on what the market can afford. Government owned NSPs, such as seen in

NSW in 2009, on the other hand, have little or no constraint on accessing capital and are consequently incentivised to overspend on capex.

2.1.2 Asymmetry of information

The asymmetry of information between regulated firm and the regulator (which is even more marked when considered against the information available to other stakeholders) is so great that a regulator must use other techniques to supplement the information provided by the firm to ensure the regulated allowances are efficient. Comparing the performance of one monopoly to another similar one is the only way to assess whether the regulated firm is efficient. This comparison is effectively benchmarking elements of one regulated firm against another – competition by comparison.

2.2 Benchmarking

Benchmarking is all about applying the effects of competition to a monopoly by comparing its performance to the most efficient monopoly service provider in the same industry. This requires the development of data from a wide range of similar enterprises and assessing the cost performance of one against the same performance seen by many, especially the entity which displays the most efficient performance.

Another technique that can be used is self benchmarking. Self benchmarking requires the application of an incentive to the regulated firm to minimise its costs. The most common incentive is one where should the entity under-run its allowance, the firm is permitted to both retain the benefits of the under-run in costs. A refinement of this is where the entity is allowed a share of this under-run in costs into the future. The AER uses the Efficiency Benefit Sharing Scheme (EBSS) to assist in self benchmarking the opex allowance for regulated firms. This has proven to be a partial answer but it is exposed to some manipulation such as resetting specific elements of opex to base assessments.

However, self benchmarking should not be used exclusively as there is no certainty that the firm has indeed reached the most efficient level – in fact the firm itself might not be aware that it is not at this level. External comparisons are therefore essential to ensure that this point has been reached.

Partial and total factor productivity techniques are used as a benchmarking tool; some regulators use partial factors for some opex elements but the risk is that some NSPs use some partial factors where it suits and then bottom up analysis where this gives a better outcome. The AEMC recently decided that it would not allow a rule change proposed by the Victorian Government to more widely use total factor productivity in energy regulation as there was not a sufficiently wide historical basis for its application. However, the AEMC did recommend that a data base be developed for the future application of total factor productivity.

Benchmarking can be used more widely by the energy regulator than is currently the case, especially in the case of return on capital (WACC) and opex. Applying it to capex is a little more difficult but still not to the extent that it should be disregarded

2.2.1 Benchmarking WACC

The development of the WACC used in regulatory decisions is currently based on the Sharpe Lintner Capital Asset Pricing Model (CAPM). This model has two basic elements (return on debt and return on equity).

Currently regulators develop both a market risk premium (MRP for equity) and a debt risk premium (DRP for debt). The MRP is derived from long term historical performance of the market and the DRP is derived from recent acquisition of debt via corporate bonds. What is concerning is that there is no attempt to compare the outcomes of the WACC development (or of the debt and equity calculations) with what is currently seen in the market. There is no attempt to assess whether the outcomes of the regulatory decision will improve or reduce the standing of the entity in the market place[8].

A major concern for MEU members has been that the WACC allowed by regulators has frequently exceeded the WACC that applies within the member companies. This is of concern as the member companies operate in a competitive market where they do not enjoy the benefits that the regulated monopolies experience, such as a guaranteed cash flow and a guaranteed return on any new investment.

An issue in particular in regulatory decisions during and after the Global Financial Crisis has been that regulatory decisions have allowed a return on debt which greatly exceeds the actual cost the regulated energy businesses incur (this especially applies in the case of government owned businesses).

The MEU considers that the pre tax nominal WACC calculated by a regulator has a close similarity to earnings before interest and tax (EBIT), EBIT is equivalent to WACC times the Regulatory Asset Base. It would be a straight forward exercise to benchmark EBIT of the market average[9] to the WACC*RAB of a regulatory decision after adjusting for the difference in equity beta. This provides a check on the actual WACC calculated to ensure that the efficient frontier is being approached.

[8] It is pertinent to note that in the early years of energy monopoly regulation, the regulators did assess the impact of the decision against a series of measures but little was done to assess these against the market as a whole

[9] This can be developed readily from market data and there a a number of firms which produce this data

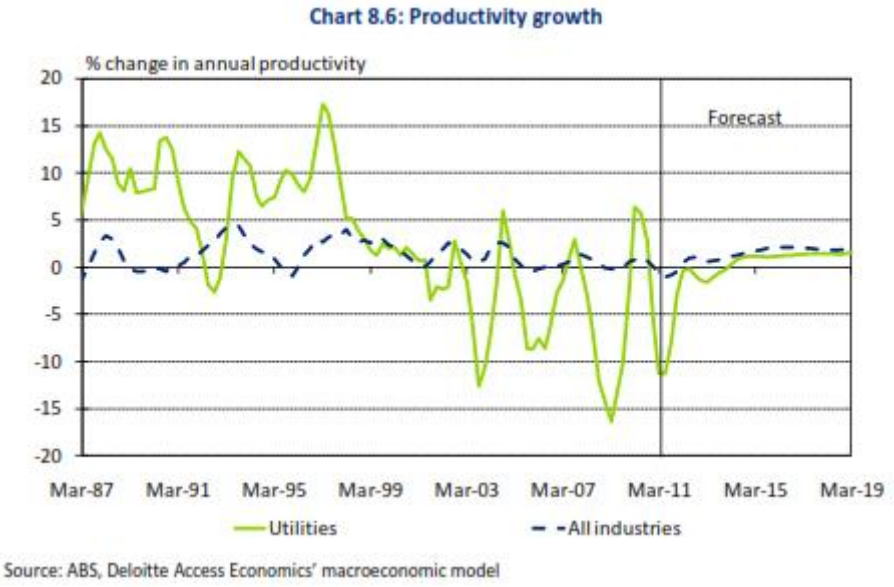
In the case of assessing the return on debt, it is important that the past performance of the regulated monopoly be assessed in a similar way to the opex is benchmarked. Debt is acquired in a variety of ways and the regulated monopoly should be incentivised to ensure that its approach to the acquisition of debt is the most efficient. The allowed debt should be set to encourage improved approaches to debt acquisition but not to exceed what the regulated entity should be able to achieve in the current climate. Self benchmarking of debt acquisition is both sensible and feasible with external benchmarking applied to ensure that the entity is approaching the efficient frontier.

Once the efficient WACC has been developed, the regulator should assess a range of financial indicators to ensure that the decision does not improve nor reduce the financial capability of the regulated monopoly to remain "whole".

2.2.2 Opex benchmarking

Benchmarking of opex (both self benchmarking and external benchmarking) has been used most frequently to set opex allowances. In the early years of energy regulation, opex benchmarking was generally used but in the last round of regulatory decisions, its use has almost disappeared. The only form of benchmarking used has been self benchmarking incentivised by the use of the EBSS developed by the AER.

A concern for consumers is that in recent times, there has been an observation that productivity in the Energy/Gas/Water (EGW) utility sector has fallen in relative terms as the following chart[10] shows.



[10] Deloitte Access Economics Forecast growth in labour costs: Queensland and Tasmania Report prepared for the AER 15 August 2011 page 52

It is apparent that regulation has not provided the impetus to maintain the improvement in EGW utilities compared to the market in general.

The main problem with setting opex by the EBSS method is that the AER has assumed that the most efficient opex has been that achieved in the most recent full year of data (year four of a five year regulatory period). This has resulted in an incentive on the regulated monopoly to maximise its opex in that year so as to set the future years at a higher level. Consistently consumers have seen the opex of a regulated monopoly under-run its allowance in years 1, 2, 3 and 5 of a period allowing the firm to enjoy the fruits of the under-run but avoid reducing the future allowances.

Another problem with the current approach is that there is an in-principle acceptance that the firm has reached its efficient level under the EBSS. Without assessing the performance of the firm against its peers there can be no certainty either by the regulator of the firm that it has become as efficient as it could. In a competitive market, the market ensures that every firm is always seeking ways to be more efficient because if it does not, then it will lose market share.

A third problem that is frequently encountered is where the regulated monopoly decides that a subgroup should not be assessed by previous performance but needs to be reset on a bottom up approach, effectively removing that cost element from benchmarking comparison.

The only way to impose the rigors of competition onto regulated monopolies is to apply strong comparative data and to remove the various methods currently used by the regulated monopolies to prevent the rigorous application of both self benchmarking to drive continuos improvement with external assessments to ensure that the efficient frontier has been achieved.

2.2.3 Benchmarking capex

As noted above, benchmarking of capex is less readily applied due to the "lumpiness" inherent in some of the capital investments required in the energy transport sector. This, of course, should not be a reason not to benchmark.

A careful analysis of the investment program of a regulated monopoly energy firm shows that the capex requirement is derived from a number of sources. These include investment for growth (augmentation), new connections, replacement, security and compliance, IT and other[11]. Of these the two large cost elements are usually augmentation and replacement although for distribution networks new connections usually becomes a large value item as well.

[11] Includes offices, plant, office operation, etc

It is by the careful dissection of the capex that it becomes apparent that benchmarking of capex can be carried out successfully. This requires the excision of the large augmentation projects (the "lumpiness") from the capex program and then benchmarking becomes essentially straightforward and useful. The few "lumpy" elements can be assessed in their own right.

Another useful tool that is available to the regulator is the ability of any firm to access capital for investment. The ability of a firm to access capital without accessing new shares is limited to the amount the firm can borrow (and still meet its financial constraints) and the amount of money it can retain from its profits, bearing in mind the need to provide a dividend to shareholders. In this regard, consumers of energy transport asset services have noted that privately owned firms tend to seek less capex allowances (and tend more to under-run those allowances) than government owned energy transport businesses.

The clear indication is that the privately owned firms have the access to capital constrained more so than government owned firms which generally access needed capital in the form of debt from the government treasury corporations[12]. That government owned energy firms have much more access to debt than privately owned firms have provides the government owned firms an incentive to invest more and this incentive is noted in section 1.4 above.

2.2.4 Summary on benchmarking

To reach the efficient frontier, competition in the wider market provides the driver to provide the most efficient service to consumers. Where there is no competition an alternative tool is required to drive improvements in efficiency – "competition by comparison" is one such tool and for this benchmarking is the only tool available for imposing this.

There has been some benchmarking of opex over the years, but this has reduced dramatically in recent years. There has been no benchmarking of the WACC or of capex yet benchmarking of these can be carried out effectively.

Not to impose benchmarking on all facets of the building block approach to setting the regulated revenue allowance, results in a less efficient outcome.

2.3 Interconnection between regions

Greater interconnection between regions provides a number of benefits – greater competition between generators, greater system security as a whole

[12] Infrequently have the government owned firms not accessed the allowed capital, although in the case of Western Power Corp (WPC) in WA, it had allowances for capital works in the current regulatory period which it did not carryout as the WA Treasury Corp did not have the funds available that WPC requested. The outcome is that WA consumers paid for investment that was not made.

and greater reliability of supply to consumers. To achieve this, more investment is required in the transmission systems increasing costs to consumer who pay for the investment.

Since the beginning of the NEM, there has been no significant investment in interconnection yet there has been massive investment (measured in $billions) in transmission networks as a whole.

The sole exception to the lack of investment in interconnection since NEM commencement has been Basslink. However, it must be recognised that Basslink was built to allow Tasmania to enter the NEM and the cost of this investment has been effectively underwritten by the electricity consumers of Tasmania who pay for Basslink through buying power from the Tasmanian government owned generator, Hydro Tasmania, which is primarily responsible for the costs of providing Basslink. It must be noted that despite Tasmania bearing the costs of Basslink, the NEM as a whole has benefited from the advent of Basslink through improved reliability and security and from better utilisation of mainland generation.

The capacity of an interconnector is not just the capacity of the assets involved in transiting the regional boundaries. For example, the Murraylink interconnector is rated for transferring 220 MW yet rarely does this occur because of the constraints deeper in the regional transmission networks in SA and Victoria. It is therefore an important element of any assessment of the capacity of interconnectors to review the capacities of the two regional networks involved. In the case of Murraylink, the ACCC which set the rated capacity of the interconnector did not fully recognise the need for the two regional networks to have a desire to contribute to increasing the transfer capability.

Any assessment of interconnection needs to reflect the realities of the drivers involved.

2.3.1 The importance of price signals.

In an incentive regime such as the NEM, price signals are provided to ensure that an appropriate response comes from the market. In the absence of these price signals, there would be a need to revert to more determinative approach by governments and regulators.

The NEM design provides a number of signals for the need to take action (such as invest in new generation) to ensure there will be continued security of supply. Similarly there are signals (service standards) to invest in transmission assets to ensure there is reliability of supply.

One of the more important price signals is the market price cap (MPC) which limits the price a generator can bid into the market and which used to be used

as a value for transmission investment. Of recent times, the MPC in relation to transmission investment has reduced and there is currently a view that the Value of Customer Reliability (VCR) used in Victoria for transmission investments should be more widely used.

2.3.2 Price signals and interconnectors

Currently the only price signal that impacts investment in interconnectors is the extent and frequency of price separation between adjacent regions which implies a greater transfer capacity is needed. However, this price signal is not used as a signal for new investment in interconnection.

The current regulatory approach considers that the value of the price separation between regions is considered to be a transfer of wealth from consumers to generators and there is no net economic benefit in including the value of the price separation in any economic test such as the Regulatory Investment Test for transmission (RIT-T). This assessment overlooks that fact that consumers pay for the costs associated with any interconnection as generators only pay shallow connection costs for their connection to the transmission network.

Generators within a region benefit from there being price separations as this gives generators in the high priced region reduced competition and, in some cases, allows the dominant generator in a region to set the spot market price because it has no competition as it knows that the region needs its output or there would be a shortage of supply.

This has been recently observed most strongly in the SA region of the NEM where the AER has identified that when the SA regional demand exceeds about 2500 MW[13], then Torrens Island Power Station must be dispatched to ensure there is supply in the region. This trigger point is some 25% below the highest demand recorded in the SA region and was the result of the SA region average annual volume weighted spot price exceeding long term averages by 50-100% in years 2008, 2009 and 2010.

As the spot price is intended to provide signals for new investment in generation, so too should they be used to provide a signal for new investment in interconnection, as interconnection is an alternative to new generation investment and because it provides a more efficient use of existing generation assets available in the NEM.

Appendix 2 is provided to show that price signals do provide justification of the investment in interconnection. This appendix is a report prepared by Dr Robert Booth of Bardak P/L and shows that the construction of the interconnection

[13] See Ed Willett (ACCC commissioner and AER member) presentation State of the Energy Market to energy 21C in Melbourne, 8 September 2009

between NSW and Queensland is justified on the economic benefit provided to consumers.

2.3.3 Consumers and the cost of interconnection

When interconnectors are congested (ie have insufficient capacity to transfer the amount of electricity available for inter-region trade) this increases consumers costs in terms of the price they pay for power (lesser competition for regional generators) and the cost of additional generation that is needed in the region but is available from the adjacent region.

As the National Electricity Objective (embedded in the National Electricity Law) requires the market to operate in the long term interests of consumers, it is logical that a regulatory test which would permit investment in augmented interconnection should reflect the total costs to consumers whether this is a result of high generation prices and/or high transmission prices.

In the recent review of the electricity transmission frameworks by the AEMC, it is recognised that the sum of the costs of generation and transmission need to be assessed when analysing the needs of consumers, and not to consider the two elements in exclusion to the other.

Thus, there is implicit support that the cost of price separation between should be included as a part of assessing the benefit of increased interconnection, especially when it is recognised that consumers pay directly for all the costs of transmission (including interconnection) other than the shallow connection costs generators are required to pay.

More bluntly put, consumers should be allowed to balance the cost premium they pay to generators when the region is islanded by congestion on the interconnector against the cost of augmenting the interconnector. As noted above in section 2.3.2, the premium paid to generators is considered only to be a wealth transfer.

Put another way, consumers see the cost of the power they receive as the total cost of the generation plus the transmission plus the distribution cost plus the retail margin. From a consumer's viewpoint the most efficient cost for consumers to pay for their power is lowest amount which is the sum of all these inputs. As the retail margin and distribution cost is the same regardless as to the source of the power, the most efficient outcome for consumers must be seen as the cost of transmission plus generation. This requires the cost to consumers of a price separation to be included in the assessment of whether an augmented interconnector would provide a more efficient outcome.

3. Responses to specific PC questions

The MEU has not responded to every question at this time. This does not mean that the MEU does not have a view regarding the question but that its view is reflected in the commentary in sections 1 and 2

Chapter	#	PC question	MEU response
1	**1**	Given the various ongoing reviews and the consultations associated with them, how can the Commission best add value? Do these reviews have the same broad objective as the Commission or are they more narrowly focused?	The PC review requires aspects of network regulation that are not included within other reviews currently being undertaken. The other reviews do not require the entity to address the issues that the PC is requested to undertake.
2	**2**	Are there any other major regulations or policies that affect the electricity market that need to be considered when undertaking benchmarking or in understanding any of the possible obstacles to investment in interconnectors?	There has been no mention as to benchmarking of the WACC and its elements, or the assessment of the financial indicators that result from use of the WACC. The MEU considers that this benchmarking is also needed. The RIT-T does not permit the cost to consumers of price separation to be included in the assessment. The MEU considers that the most efficient cost for consumers reflects the sum of the generation cost and the transmission cost. When these are added, the cost of price separation is included as a balance to the cost of augmentation
3	**3**	What are the best (and worst) aggregate measures of performance, and why is this so? In which contexts (Australia and elsewhere) have these been most credibly been used?	What is often overlooked is that service performance is an integral measure that must be used to assess the impacts of capex and opex. This can only be assessed in retrospect but if the service performance is maintained (or even enhanced) with certain opex and capex levels, then this is a strong indication that these levels are a good indicator of efficiency of capex and opex.

	4	What partial indicators are meaningful? Are there particular parts of network businesses that are easier to benchmark? What are these, why is it easier, and what have benchmarking studies revealed?	As noted above, opex and capex have to be reduced to their basic elements and these must be used to measure past performance. Equally, as a top down assessment, combined costs need to be benchmarked
	5	Are there criteria beyond those identified in box 1 that are useful for discriminating between good and bad benchmarking tools and approaches?	
	6	What are the weaknesses and advantages of full versus partial measures for benchmarking?	
	7	What methods should be used for benchmarking (indexes, corrected ordinary least squares, data envelopment analysis, simple ratios), and what are their strengths and weaknesses?	
	8	Could benchmarking be used to assess the effectiveness and efficiency of different regulatory settings (such as reliability standards)?	Benchmarking must reflect different regulatory settings. However once the regulatory settings are achieved, this indicates that the opex and capex used provide an indication of the efficiency of the amounts used.
	9	Are there examples where regulatory benchmarking has been used in electricity networks in Australia or overseas?	Benchmarking is used widely both in electricity network performance and in other industries. Partial productivity factors have been used most recently in regulatory determinations by the Utilities Commission in NT regulating Power and Water Corporation
	10	Are there any other broad benchmarking approaches not discussed above, and	As noted in section 2, the MEU considers that the WACC elements and in whole should be benchmarked to ensure comparability

		where and how have these been used?	
4	**11**	Is there a big enough problem to justify new approaches to benchmarking and to incorporate it into regulatory incentive arrangements? To what degree could perceptions of inefficiency reflect the newness of the current regulatory regime or a failure to sufficiently adjust for the differing starting points of different distribution businesses?	Benchmarking is hardly used at all in the NEM. So the current approaches are not a problem. The problem with not using benchmarking is that there is a concern that the efficient frontier is not being approached and there is no measure as to whether the network is efficient. It has been noted by the MEU that networks try to minimise the use of benchmarking on the grounds that their network is different. If there is no benchmarking the regulator, the business and the consumer are not assured that the costs allowed are efficient. All networks have had two and many even three regulatory reviews since the beginning of the NEM. Regulation is no longer new but there has been a continuing decrease in any benchmarking being carried out, with greater reliance being placed the regulated firms providing efficient cost levels which are seldom benchmarked, it at all.
	12	How do existing network suppliers assess the efficiency and performance of their own businesses and how do they use these results? Could these results have relevance to regulatory benchmarking, and if not, why not?	In the absence of external benchmarking, the existing businesses rely on past performance and their ability to use less opex than that allowed. Capex is generally developed and explained to the regulator on a bottom up approach with little reference to past performance.
	13	How should benchmarking be used by the regulator? For example, to what degree could and should it be used as 'high-powered' incentive regulation; as a basis for determining the weighted average cost of capital and efficient spending; or as	The regulator should use the outworkings of benchmarking to test and ultimately influence the actual allowances for opex, capex and WACC. It is accepted that in achieving the efficient frontier, the regulator should impose slowly the outcomes of benchmarking to ensure that the regulated firm has sufficient funds to carry on the business activities as it trends towards the efficient frontier. But the ultimate goal must be that the regulated firm is driven over time to achieve the efficient frontier. In

		public information to provide moral suasion for efficiency?	the absence of external benchmarking, there is no way of assessing whether the efficient frontier has been achieved.
	14	What is the magnitude of the benefits from using benchmarking in regulatory decision-making in terms of lower unit costs or other performance measures?	The potential rewards to consumers of achieving the efficient frontier are significant. For example, benchmarking of debt risk premium would deliver to consumers, at no cost to the regulated firm, many hundreds of dollars in savings. Similarly it is expected that savings in capex and opex by reaching the efficient frontier will be of a similar size. In his update #8 Garnaut makes the similar observation. The fact that the costs of network services has risen by so much as they have in the past round of regulatory resets, supports this contention. See appendix 1 for an example of the extent that opex and capex increased
	15	What are the lessons from overseas about their benchmarking approaches, and what aspects should Australia copy or avoid?	
	16	To what degree could the AER use international benchmarking?	It is accepted that Australian conditions are different to those in some other overseas jurisdictions. However these can still provide some useful information. The regulated firms themselves use international benchmarking (eg ITOMS)
	17	How can a good benchmarking model be identified since data and methods always have some imperfections?	There is a need for a consistent approach for the gathering, manipulation and display of data to make the best use of benchmarking. However, even imperfect data can provide useful insights and should not be excluded, even though its use might be minimised
	18	Is there value in 'rough and ready' benchmarking models and how would these be used?	As with the previous answer, "rough and ready" can provide a strong indication as to whether the proposed opex, capex and WACC outcomes are grossly inefficient and whether deeper analysis is required to ensure a more efficient outcome is possible.

	19	What are the most important control factors for benchmarking network businesses (for example, lot frontage, asset vintage, topography, weather variations, customer types, reliability standards, ratio of peak to average demand, and any strategic behaviour by generators and retailers)? What matters less?	Development and use of the benchmarks will determine those that are most useful as well as using internationally used benchmarks
	20	What are the main differences in the potential for, and methods of, benchmarking transmission versus distribution businesses?	There are differences but there are also similarities whether cross benchmarking between the sectors can add value
	21	Should benchmarking results and methodology be publicly available, and if not, why not?	yes
	22	What are the consequences of errors in benchmarking? To what extent do these costs vary for positive versus negative errors? How could the costs of any errors be reduced?	As noted above, there is a need for a regulated firm to have time to reach the efficient frontier. If its awarded too little revenue which is based on the efficient frontier, then the firm could be in financial trouble which would be a worse outcome for consumers. However, the efficient frontier must be approached over time. By allowing time to reach the efficient frontier, the risks to consumers are minimised and the affect of errors greatly reduced.
	23	To what extent would it be helpful to give the AER some discretion in deciding how much weight should be given to benchmarking and other tools when making regulatory determinations?	The AER should be required to develop the suite of benchmarks that should be used for each of transmission and distribution. It should be able to vary the weighting of each measure at each reset, provided it explains why it has varied from the norm. This allows the AER to make allowance for specific differences.

	24	What if any, alternative policies may be superior to benchmarking? What, if any, policies could complement the use of benchmarking?	The MEU considers that self benchmarking combined with an incentive scheme plus the use of external benchmarking will provide over time an ability for the regulated firms to reach the efficient frontier
Testing	**25**	What are the principal reasons for the apparent decline in the productivity of the electricity networks and for the associated increases in electricity prices? In particular, what have been the effects of rising input prices, past underinvestment, building ahead of use, rising peak demand, underground cabling and requirements for reliability requirements? To what extent have investment responses to the above factors been economically efficient?	It must be noted that service performance of networks have increased over time despite the fact that there has been supposedly an underinvestment in the networks, implying that historical underinvestment is not a cause. This is supported by the fact that replacement capex has not been a major driver of higher capex The regulators (national and state) all made allowances for higher exogenous input costs so this is not a reason Rising peak demand has not accelerated in recent years any more than in earlier years, so this is not a cause. There have been some modest increased requirements in reliability settings in some regions, but the rising costs have been seen across all regions, so this is not a cause The MEU considers that Garnaut's assessment is correct that there has been significant inefficient investment. The MEU considers that the main issue is that the Rules have provided an over-incentive to invest (too high a WACC combined with no risk for over-investment) and this is being addressed by the AER proposed rule changes for network regulation. The MEU also considers that the lack of appropriate benchmarking has also led to the large increase in opex and capex
	26	To what extent have rising network costs reflected failures to correctly define project scope, to adequately control project costs and 'gold plating'?	

	27	If there has been gold plating by network businesses, how has this been realised (premature investment, over-specification of network elements, excessive reduction in service interruption risks)?	
	28	What is the evidence about the comparative roles of the above factors?	
	29	To what extent have Garnaut, Mountain and Littlechild identified genuine inefficiency in electricity networks?	See comments above
5	**30**	Do the current Rules limit the use of benchmarking? If so, how do they do so, to what extent, and what would be the appropriate remedy?	Yes. The reason is driven by the propose/respond model rather than the consider/determine model of regulation used the Codes. The AER considers that it is constrained to apply better benchmarking by the use of the propose/respond model. To a degree this can be overcome by the Rules stating that the AER has the powers to set the efficient levels rather than being constrained to accept a proposal that might be considered to be near efficient. Essentially the current Rules require the AER to always accept a proposal that is at the high end of an acceptable range
	31	In particular, do the Rules restrict the weight that the AER can apply to benchmarking analysis compared with the information that distribution business make available in the building blocks proposals? For example, could the AER reject the evidence from the building blocks analysis if it found compelling alternative evidence of	This is a moot point. The AER should have this power but considers that it does not. The networks have alleged that they consider the AER has the power yet the networks have also used the limited merits appeal process to ensure that the AER is not able to exercise the power to use its discretion.

		lower required spending from benchmarking?	
	32	Must the AER forensically examine each aspect of the building blocks approach even if it believes that a more simple and robust benchmarking approach were available?	The AER should use whatever evidence it has available to it to be able to determine the efficient allowance. The AER should then be able to set the efficient level.
6	**33**	Are there any other limitations faced by the Australian Energy Regulator in using benchmarking, such as the merit review process?	Yes, see answer above
	34	What restrictions, if any, should apply to the AER's use of benchmarking or other analytical tools?	None – the AER should use whatever tools it considers appropriate to identify and set the efficient level
	35	Should the AER select the best performer as the benchmark, or choose a benchmark close to, but not at the frontier? What criteria could be used to determine the threshold between unreasonable and reasonable costs?	The AER must ultimately set the allowance at the efficient frontier, although as noted above it should allow sufficient time for the regulated firm to reach this frontier. To allow the use of a value which is not efficient puts the regulatory approach of competition by comparison at risk.
7	**36**	In cases where the AER's benchmarking findings cast doubt on building block proposals but do not provide an exact alternative, should there be scope for the AER to negotiate a settlement with network businesses? How would that be achieved?	The AER must set an allowance which is efficient although time might be needed to get to this level.
	37	Could benchmarking reduce prescriptive regulation in the Rules? How? Which	The Victorian government proposal for using total factor productivity to set future tariffs is a trend away from the building block approach and

		ones??	prescriptive regulation. TFP is a form of benchmarking which does result in less prescription but is dependent on the initial allowance being efficient first. If the initial allowance is not efficient, TFP provides for the inefficiency to be perpetuated. Therefore benchmarking is seen as as the essential first step to reach the efficient frontier.
	38	How would a regulator use benchmarking analysis that produced cost estimates significantly different from those from the building blocks approach? What approaches have other countries used in such instances?	If the building block approach gives a significantly different outcome to benchmarking either the building block allowance is inefficient or the benchmark is not appropriate, or both. The AER should have discretion to identify how to address the difference
	39	Has the AER used benchmarking effectively? Should it adopt different practices? Are there any major process or resource obstacles to the AER's use of benchmarking?	The AER has not used benchmarking effectively and yes it should adopt different practices. The reasons for this probably lie with the regulatory approach (propose/respond) the AER must implement.
	40	Is there scope to introduce competition in parts of the electricity network? If so, where and when? Would that reduce any need for benchmarking in those parts? To what extent could performance in competitive segments be used as benchmarks for non-competitive segments?	Probably not. VENCorp (now AEMO) has tried to do this in the Victorian transmission network but the outcomes have not been promising.
	41	To what extent, if any, are there flaws in the AER's current benchmarking of the WACC, and if so, how could it be improved?	The AER has not applied benchmarking to the development of the debt risk premium. It has continued the use of an equity beta which is demonstrably higher

			than that benchmarked in the wider market
	42	Is there evidence that the regulatory WACC should be different for government owned compared with private network businesses? What implications would differential WACCs have for the eventual privatisation of such businesses?	Yes. Government owned firms access debt from the state Treasury Corps which borrow at the State's credit ratings. The T-corps lend to the government owned network firms at the rate they borrow at plus a Competitive Neutrality Fee (CNF) to reflect its standalone credit rating. Whilst there is no government guarantee, the CNF premium is quite small and certainly delivers a debt risk premium well below the levels set by the AER. There is no reason why consumers should pay a premium for the cost of debt that is not incurred (debt should be a cost recovery) Potential privatisation should not be a reason to allow a government owned network to recover a greater profit from consumers
	43	What, if any, are the effects of the various WACC determinations on: • the incentives of private versus government-owned network businesses? • choices about spending on capital expenditure versus operating expenditures?	A greater WACC than that needed will incentivise greater capital investment If the DRP is seen as a cost recovery element, then the provision of an inflated DRP does not provided an efficient allowance and provides incentives for unnecessary (= inefficient) capex
	44	How can the different patterns between forecast and realised spending between private and government-owned network businesses be explained?	As noted in section 2.2.3, privately owned firms have their capex constrained more so than government owned businesses which can access debt more readily at lower costs.
	45	How does the efficiency of private distribution businesses compare with government-owned ones, and if different	The only greater efficiency private networks have is that they have a constraint on the access to capital, making them use their available capex more efficiently and not to over claim on capex that they cannot

		why and how would this be remedied?	access. There is an incentive on the private network firms to over claim on WACC and on opex
	46	Do government-owned network businesses have any non-commercial objectives? How do these vary by business type or jurisdiction? How do they affect the behaviour or efficiency of the businesses? Should they be removed or altered? Should they be factored into benchmarking analysis?	No, they should not, although their government owners at times have imposed requirements that they return a higher dividend than is warranted from the business structure. This has resulted in the firms using their benefits of lower WACC and easier access to capital to provide the higher dividend. The government owned businesses need to be commercial as their directors are required to maximise the profit to their shareholders. The difference is that government owned firms have a lower cost of capital and the ability to access capital more readily. With these benefits available there is a lesser constraint to control their capex needs. and therefore there is not the same constraint
	47	While government-owned businesses pay corporate taxes to state governments — consistent with competitive neutrality principles — are those principles undermined by the shareholder status of governments or any other governance issues? Does that affect investment decision-making by government-owned businesses or the determination of reliability standards and other policies by governments?	From a consumer viewpoint, it does not matter whether the income tax payable goes to the Federal treasury or a state treasury. What does matter is that the government owner is incentivised to drive the government owned firm to chase increased profits as the government receives both the higher dividend and the higher corporate tax receipts which occurs when the government owned firm profit is unnecessarily high. As the government provides lower cost debt through the T-corps, and does not significantly limit the access to the debt, then the investment decisions of the government owned network are influenced by their shareholders. State governments set the reliability standards with little reference to the cost of these standards and thereby essentially influence the capital needs of the network firm.
	48	If any biases towards excessive investment	No. Benchmarking is still needed to ensure the revenue allowance is

		posed by the WACC and the rollover arrangements of the regulated asset base were removed, would that eliminate the need for further development of benchmarking?	efficient. Removal of these biases will assist in driving the outcomes to be efficient as there will be less incentive to invest and thereby the investment will be better targeted
	49	To what degree do different jurisdictions' reliability standards affect costs, if at all? Do different standards affect the potential and/or incentives for a single network business to extend its network across borders?	Setting the reliability standards unnecessarily high increases the need for capital and increases opex. An efficient balance of reliability and cost will provide consumers with the best outcome. It is important to ensure that the desire by consumers for improved reliability is tempered by the cost of this. Too often governments have set reliability standards too high without understanding to cost implications of their decision. The regulator is better placed than governments in setting the balance to one which best meets consumers needs. There has been no indication that a network has sought to broaden its geographical coverage because of different standards of supply as setting of standards is done on a geographical basis
	50	Why have reliability standards been increased over time, and what impacts have these increases had on costs?	Reliability standards have increased since the decision was made to set the costs of network service independent of the reliability standards. Costs have risen with the increase in reliability standards.
	51	To what extent would adoption of a probabilistic versus deterministic framework change costs? What risks and benefits would this entail?	
	52	What evidence is there of customer involvement (such as willingness to pay) in setting reliability standards?	The ability to pay has not been a factor in regulatory decisions since governments handed over control of costs to the regulatory regime. The regulator does little to assess ability to pay as this isnot a regulatory requirement.

	53	How are existing reliability incentive schemes functioning and how could benchmarking contribute to their design?	The reliability incentive schemes have only been imposed on transmission and are too low powered to deliver an appropriate balance.
	54	What is an appropriate governance structure for setting and monitoring reliability standards, and what is the rationale or evidence base for different standards across jurisdictions?	Setting and monitoring of reliability should be part of the regulatory structure and not done separately by government. This allows the cost of reliability to be a determinant in the setting of reliability.
	55	To what degree should a jurisdiction that specifies a higher reliability standard than others justify such a requirement to its constituents based on a transparent cost-benefit analysis?	There is a basic concern amongst consumers that reliability for customers of the same class but in different geographical locations in the same network pay the same cost for the service but receive different reliability. This is inequitable.
	56	What role could demand management play in reducing peak demand, how would it work, how much would it cost, and what network savings would be experienced? In which parts of the network are cost savings most likely and why?	Demand management is proven to be able to reduce peak demands by loading shifting and to reduce electricity consumption. The main problem with achieving such reductions is that the networks are incentivised (especially those with a price cap regulatory regime) to prevent the introduction of demands side participation as this reduces the networks need for investment (and hence profit) and reduces network revenue by the lower consumption (large amounts of network revenues are provided from consumption). In proportion, embedded generation incurs more costs for connection than large generation and networks are loath to provide any reward for reducing the demand that such embedded generation provides a network
	57	What are the regulatory and other obstacles to demand management or other	See response to question 56 above

		approaches that give consumers choice? How are these changing?	
	58	How do network providers model and make financial decisions about the impact of peak demand growth on network adequacy, including identification of the most cost-effective network investment solution (for a given reliability standard)?	
	59	How could benchmarking or other tools identify the degree to which network businesses have efficiently used demand-side management as substitutes for building redundancy in their networks?	
	60	What is the evidence about the effectiveness and customer acceptance of demand management provided by the various trials and experiments in Australia and internationally? What factors have inhibited the use of already installed smart meters?	Many studies have demonstrated that consumers need a clear and realisable reward to provide demand side participation and this reward needs to reflect the effort that DSP requires of the consumer. The consumer tends to expect a reward in terms of a cash benefit rather than the avoidance of costs. The expected rewards tend to exceed the value to the network receives from the DSP although the benefit to the market as a whole probably exceeds the expected rewards. The lack of the ability to aggregate all the rewards of DSP from networks, retailers and spot market makes it difficult to pass onto consumers the full benefits of DSP.
6	**61**	To what degree are interconnectors important to greater competition and greater efficiency in the NEM (once account is taken of the costs of construction and	Interconnectors provide two main benefits to the market – increased generator competition and increased reliability – both of which deliver greater efficiency. In addition, increased interconnector capacity reduces the ability of the dominant generator(s) in each region from exercising market power at

		any collateral investments required)?	times of high regional demand. This would prevent the observed transfer of wealth from consumers to generators when there is adequate generation capacity in a region but which is driven by market power rather than a shortage of supply The market signal (the spot price) that is generated as a result of market power provides a spurious indication of a shortage of supply resulting in potentially unnecessary investment (which would be inefficient)
	62	What is the magnitude of the impacts on prices, generator capacity and the use of renewable power arising from any deficiencies in interconnector investment? In effect, do any flaws matter much?	The signals that the market provides indicating a need for generation investment should be used to justify the need for investment whether this is for more generation or increased interconnector capacity. Currently the spot price signal is only used for signalling more generation. The market signal should be used to deliver the lowest cost option from a range of investment options, including increased interconnection. See appendix 2
	63	What empirical methods could be used to indicate the scope for further interconnectors?	Market signals should be used (as intended), such as the region price differentials. To exclude the cost to consumers of price separations when assessing a need for relieving congestion at regional boundaries is not efficient but is what occurs under the current approach
	64	What are the obstacles to efficient interconnector investment and how could these be overcome?	The first obstacle is the decision not to use the cost of congestion sees by consumers. The second obstacle is the need to strengthen intra-regional networks to allow the interconnectors to operate at rated capacity when demand is greatest. To achieve this requires direction to the intra-regional networks to augment where there is a need to allow greater inter-regional flows. Currently the intra-regional network is permitted to invest where it wants.

	65	Are current coordination and planning arrangements efficient?	There have been changes made over the life of the NEM to try an get a greater ability to impose on regional networks to invest where the market needs investment (such as points of congestion). Tthe market incentives on TNSPs generally do not drive to this achievement although the recent move by the AER to introduce a bonus/penalty arrangement for TNSPs to reduce congestion will assist as will the national planner function of AEMO. However the fact that there has not been investment in interconnection since NEM commencement unless it was driven by a government (eg Basslink) indicates that the current incentives are too low powered or poorly focused. The Coordination role by AEMO is useful but there is still no compulsion on any party to invest to increase interconnection capacity.
	66	If more interconnection is efficient, how much and where would the additional capacity be built?	The need for interconnection can be seen from the frequency, length and size of price separations between adjacent regions – this is a clear market signal but one that is no used to justify interconnection capacity. The most recent example of this has been between SA and Victoria in years 2008, 2009 and 2010 implying more interconnection capacity was needed. With more wind generation in SA being built, there will be times in SA where wind generation will have to shut down because the surplus wind generation will cause binding on the SA/Vic interconnectors. There is probably also a need for more interconnection between NSW/Vic and NSW/Qld. The amount of increase will depend on the size of the market signal
	67	Why should regulations for transmission and distribution investment be different?	Distribution is essentially about delivering small amounts of power to many customers from a few receipt points near load centres. Transmission is about delivering large amounts of power from many

			generators to a few delivery points near load centres. Investment in transmission tends to be more "lumpy" than distribution and therefore tends to require a longer term outlook. Market signals tend to apply more to transmission than distribution.
	68	What are the advantages and disadvantages associated with various options to improve interconnector efficiency, taking into account that some potential solutions (such as public contest methods) may have far-reaching impacts on other parts of the market? What changes in distribution and transmission regulation would be required to permit more market-based interconnector arrangements?	The current market signals are probably sufficient to indicate where increased interconnection is needed. What is required is that these signals be used to substantiate where the most efficient outcome will be eg more generation increased interconnection or a combination of both. What is absent from the analysis is the fact that consumers see the cost of generator plus transmission, but market analyses still look at generation and transmission as separate activities and each is therefore examined in isolation. By combining the two costs together when analysing the needs of the market and to identify the lowest cost option for consumers, the most efficient outcome will be developed[14].
	69	To what extent is it likely that prospective upgrades in interconnection capacity will resolve the currently perceived problems without a need for policy changes? Are longer-term policy changes required to ensure longer-term upgrades?	AEMO has identified there is no new interconnection needed until 2018 (between SA and Vic) based on its forecast of current and planned new generation. However this analysis does not allow for the costs of consumers of regional price separations (which are currently viewed as transfers of wealth). Market price signals indicate that increased interconnector capacities might well be required sooner than this. Currently the electricity Statements of Opportunities (ESoO) highlight a

[14] An example of this was identified in the case of new wind farms. A proposal was developed where the wind generation on Eyre Peninsula in SA is very efficient, but requires a very large cost to deliver the power to load centres. As the cost of transmission is paid for by consumers, this option was seen as very attractive in terms of generation. A study was undertaken by the Clean Energy Council which identified that a more efficient option was to build less efficient wind generation close to existing transmission systems – ie when the total cost of generation and transmission were combined, less efficient generation was overall more efficient from a market viewpoint.

			shortage of generation capacity but not how this might be addressed other than generation investment. What needs to occur is that the ESoO should identify the most cost effective solution which would be a mix of generation and transmission. The AEMC is examining better methods of reducing congestion caused by inappropriate generator location and hopefully this should reflect the combined cost of generation and transmission (including interconnection)
	70	Will the value of greater interconnector capacity rise as carbon pricing creates larger cost margins between competing generators located in different states? If so, to what extent?	Yes. The cost will be signalled by the frequency, duration and extent of price separations between regions. Such an approach indicates that unless the benefit to consumers (not the market) is more than the cost of the interconnector investment, then the more efficient outcome is to retain the costs of price separation
	71	Given the AEMC's ongoing review of the transmission framework, where can the Commission add the most value to interconnector policy issues?	Ensuring the AEMC recognises that • the economic benefit of investment in transmission needs to be assessed in terms of consumer benefit (ie the benefit of the investment should be recognised as a benefit to the party paying for the service) rather than in terms of a net market benefit • The lowest cost option for new investment needs to be seen in terms of the cost of generation plus the cost of transmission
	72	What are the lessons from other countries' approaches to interconnector investment, including the Argentinian approaches and the new cost allocation principles of the United States Federal Energy Regulatory Commission (Order 1000) released in July 2011?	

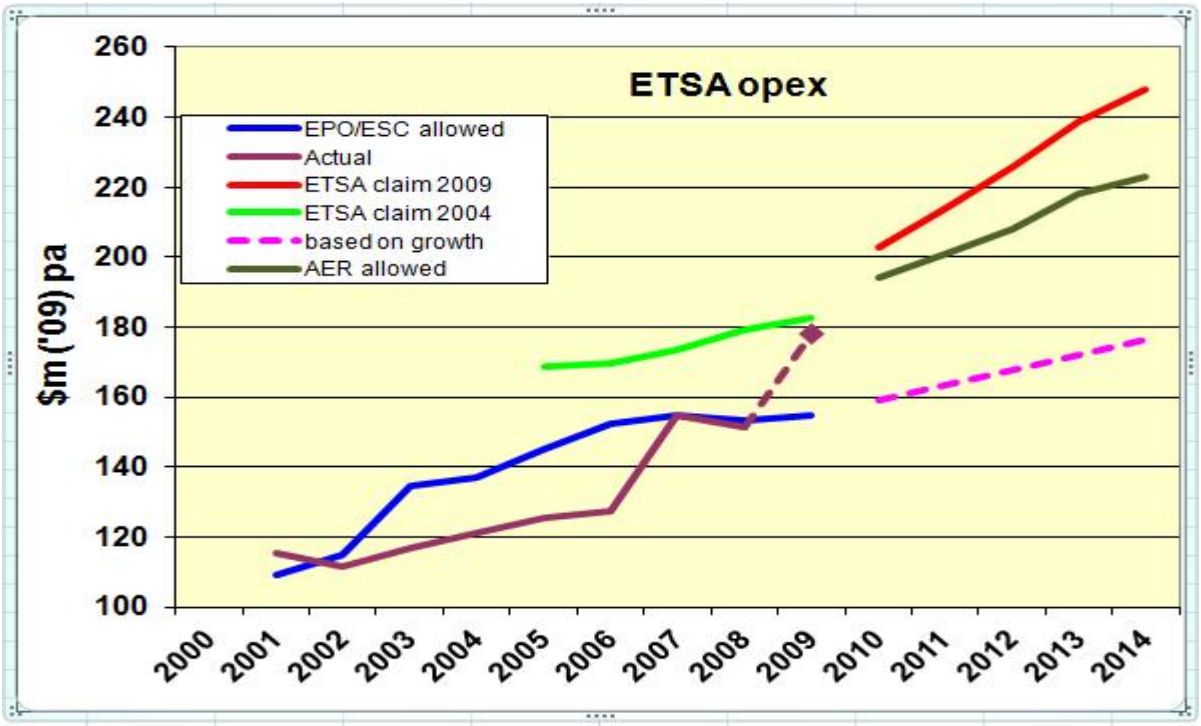
	73	Taking account of the costs of interconnectors and their transmission losses, to what extent could congestion and price separation events be better addressed by alternatives, such as more investment in transporting gas to gas-fired generators, or by using distributed generation? Are there barriers to such alternatives?	The best long term outcome for consumers (as is required by the Electricity Objective) is where the lowest cost option is developed where all of the costs of generation and the costs of transmission for each option are compared. Examining options purely in terms of generation or transmission independently will not meet the intent of the Objective nor will it provide the most efficient outcome
7	**74**	To what degree does the type, location and conduct of generators affect the efficiency of the electricity network? What are the implications of any such impacts?	Under the Rules, generation does not see the true costs of their locational decisions (eg the costs for augmenting transmission to relive the congestion the locational decision causes). Until this is rectified, locational decisions for generation will be made in terms of the lowest cost for the developer of the new generation.
	75	How would benchmarking of network businesses, or its application in regulations, take into account any such complexities?	Generators need to pay the deep connection costs for their locational decisions
8	**76**	What are trends in electricity supply and how will these affect regulation, and the need for, and use of, benchmarking and other regulations?	
	77	To what extent, if at all, will renewable generation and household feed-in tariffs require network upgrades. How costly and efficient would it be?	
	78	Is local small-scale power generation likely to develop cost-effectively to such a degree	Distribution networks will always be monopolies as they will always be needed to provide back up to the self generation of consumers.

		that it (a) erodes the distribution network natural monopoly (b) significantly reduces network investment requirements? If so, how long before this happens, with what technologies and costs, and with what implications for regulation? Are there obstacles to efficient distributed generation?	However, significant development of distributed generation should reduce the need for network investment. However, network pricing approaches militate against widespread distributed generation as networks use the need for providing backup to each self generator to effectively reduce the benefit of distributed generation to the consumer and in most cases make such self generation uneconomic.
	79	How fast will Australia move towards 'smart grids'? How much will these cost, and what impacts will they have on reliability and overall network investment? Will they provide better evidence about the comparative performance of different network providers?	
	80	To what degree could the likely future development of better benchmarking tools be incorporated into current incentive regulations to reduce any bias towards excessive investment? How should any such incentive regulations be designed? What are the major advantages and disadvantages of such incentive arrangements, and in particular the magnitude of any risks that such an approach could chill efficient investment? Are there any similar arrangements in	Significant progress can be made quite readily to reduce the bias for overinvestment by modifying the rules. Such changes would include a need for ex post review of capex, optimisation of assets, benchmarking WACC, assessing capex against the inherent ability of the network to provide capital, benchmarking the timing of capex, etc

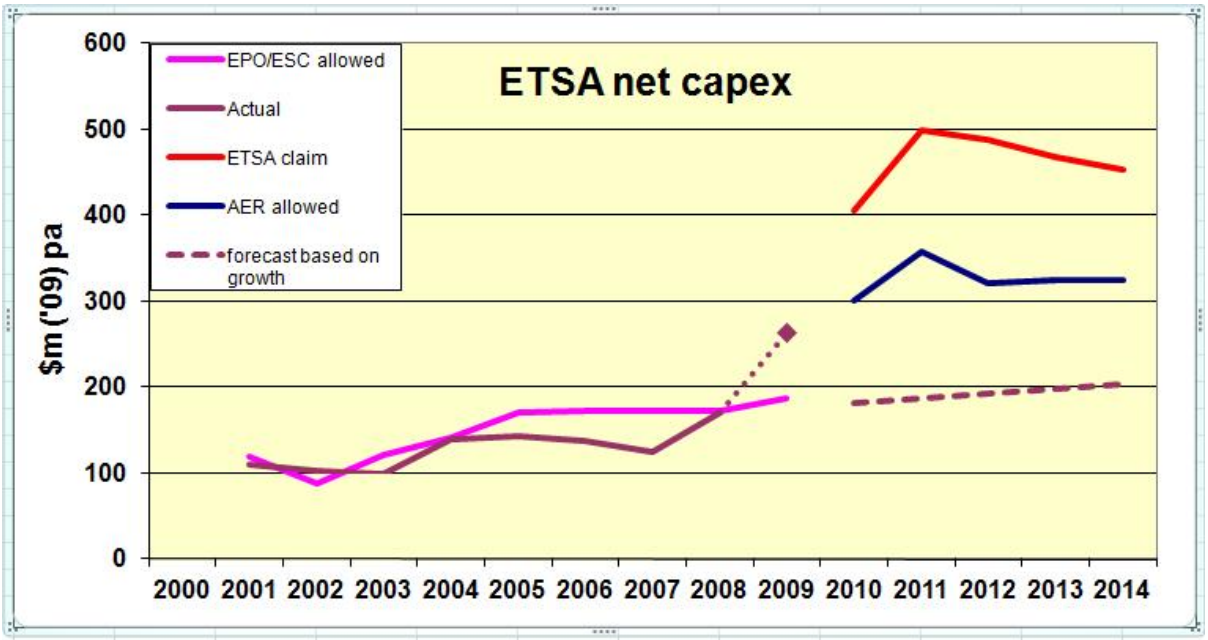
		utilities or other regulations that provide lessons on such incentive arrangements?	
9	**81**	How should policy change be implemented, what are the priorities and how long will it take? Is there a critical sequence of changes that should take place?	The imposition of benchmarking on network regulation has always been present, so a stronger requirement should not create adverse outcomes. Assessing interconnection benefits to consumers rather than on a market basis is readily achievable and should not result in any untoward outcomes This implies that changes can be readily implemented immediately
	82	Are there significant costs in implementing change?	No, rule changes are being assessed on a continual basis and slightly changing the rules to increase the effectiveness of benchmarking or interconnector assessment would be incremental change rather than a major change in direction
	83	Which agencies/parties should do what when implementing change?	The SCER should introduce the necessary rule changes, the AEMC should make the changes and the AER should implement the changes
	84	Is there any interaction with other policies/regulations that would affect the effectiveness of implementation?	
	85	Given the experience of the last five to 10 years, over the longer term, how should the NEM be modified to meet the best interests of consumers?	The MEU has proposed above, the changes it sees necessary to improve the NEM in terms of benchmarking and interconnection investment. The other changes the MEU considers are needed are not related to these two basic issues.

Appendix 1

A typical outcome of an AER reset under the new Rules compared to the regulatory decisions by regulators under the Electricity Code



Source: MEU affiliate ECCSA response to AER draft Decision on ETSA utilities



Source: MEU affiliate ECCSA response to AER draft Decision on ETSA utilities

These show that the first two regulatory periods were typified by relatively modest growth in opex and capex and reflected the growth in demand which is the main driver for investment, but under the new Rules there was a very large increase in both the claim for increases but also the regulatory allowances.

Appendix 2

An assessment of the first six months of operation of the QNI Interconnection

by Robert R Booth[1] ©

Background to Paper

The subject of the proper role of interconnections between States/Regions in the Australian National Electricity Market is currently under active discussion.

The strong interconnections promised when the concept of a National Grid/National Market was first suggested in 1990/91 have not eventuated, and the present excessively complex and prolonged rules for evaluating interconnections, the choice between regulated and "market" interconnectors, and the inability to contract across interconnectors, are all under active discussion and have been identified as problems in need of solutions.

In addition, there has been a (rather belated) realisation that the compulsory, single priced, energy only pool structure which is employed in the Australian NEM is prone to exploitation by the limited number of generators possible in Australia as a whole and in the individual Regions. The role of interconnections in reducing the scope for the exercise of market power to exploit the weaknesses in the pool structure is currently under debate, especially in association with the proposed SNI interconnection between NSW and South Australia.

The QNI interconnection, between Queensland and New South Wales, began operation early in the year 2001, with its capacity initially limited to around 300MW and 350MW in the northern and southern directions. These capacities have been progressively increased to 700MW and 750M by late June, and it will have a capacity of 1000MW southbound and at least 500MW northbound after the Millmerran power station is commissioned next year.

QNI was (mercifully) spared the NEM evaluation process, having been approved by the two State Governments prior to the NEM coming into operation by way of a derogation to the National Electricity Code.

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[1] An independent consultant and commentator on energy matters and author of the book "Warring Tribes — The Story of Power Development in Australia". See www.bardak.com.au for details.

Queensland (along with South Australia) was subject to rather obvious exploitation of the market rules by the generators from the start of the NEM. Wholesale prices were very high in both States, the incidence of price spikes and thus volatility, was high and the rebidding statistics showed much higher numbers than in Victoria and NSW.

The first six months of the calendar year 2001 provides a small but revealing case study of the effect of a regulated, free-flowing substantial interconnection on wholesale prices in the NEM.

Compared to the previous identical periods in 1999 and 2000, the only changes which took place in Queensland had been the commissioning of a 180MW HVDC interconnection between the lower voltage transmission networks in northern New South Wales and southern Queensland in July of 2000, and the early stages of commissioning of a 420MW unit at Callide C. While both of these projects would have had an effect in pool prices in Queensland, their effect appears to have been small compared to that of QNI. This study has not attempted to segregate the various effects, but simply looks at the overall changes in the Queensland pool prices in the critical summer months.

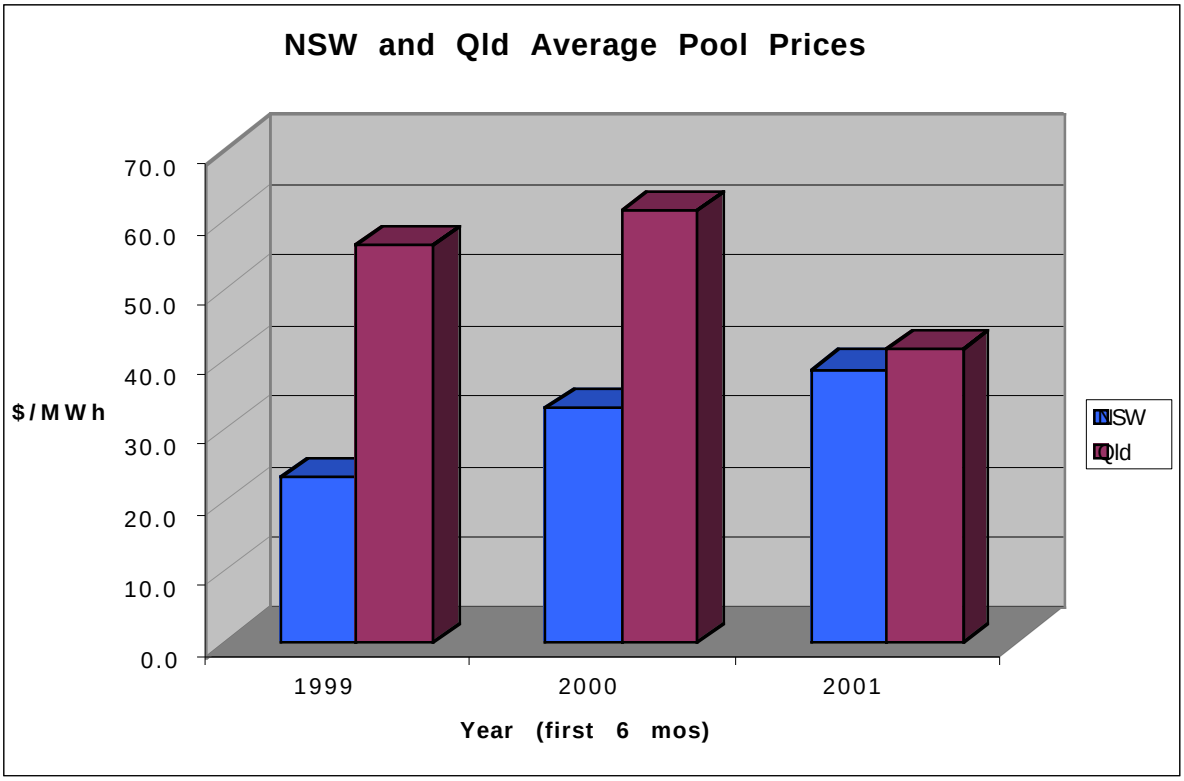
For example, the differential between average pool prices in Queensland and New South Wales for the last six months of 1999 was only $8.1/MWh — considerably less than the differential in the first half of the year. The same figure for the year 2000 was $4.7/MWh — a reduction, but of small absolute magnitude. Directlink was operating during this period, but the magnitude of any effect which it may have had is too small to identify from the data.

The problem with Directlink, and other so-called "market network service providers", in contrast to normal regulated interconnectors, is that they must seek to maintain a certain differential between regional pool prices in order to gain revenue to cover their annual costs — of the order of $10/MWh based on typical costs of HVDC systems of the size used in Directlink. In this respect, they have motivations more like those of generators to keep a high pool price in the receiving system. In addition, any benefits from the operation of such a link primarily accrue to the owners of the link and do not necessarily flow to end customers and retailers.

Regulated interconnectors have no such constraints placed upon them and operate to enhance competition between generators, equalise pool prices (apart from losses) and benefits flow much more directly to customers and retailers.
We have concentrated on the effects on Queensland because, arguably, the pool price in New South Wales and Victoria moves according to its own set of circumstances, since the relative size of the southern system is almost three times that of Queensland.

Relative Pool Prices in Queensland and New South Wales

The graph below shows the average pool price (time weighted) for the first six months of the calendar years 1999, 2000 and 2001.



The New South Wales (and Victorian) pool prices rose over this period, driven primarily by generator behaviour in Victoria as the demand/supply balance tightened and exploitation of the market rules became apparent.[2]

Queensland pool prices were very high from the start of the NEM in December 1998 and remained high in 1999 and 2000. Note the very substantial decrease in the first six months of 2001.

Also of note is the reduction in the number and magnitude of price spikes — an indication that the opportunities available to the Queensland generators to manufacture shortages and gain high prices has been substantially reduced.

The graph below shows the differential between the average Queensland and New South Wales pool prices for the same six month periods.

While substantial in both 1999 and 2000, the differential has collapsed in the first part of the year 2001 to just $2.8/MWh or about 7% of the New South Wales price — generally close to the losses across the QNI interconnection.

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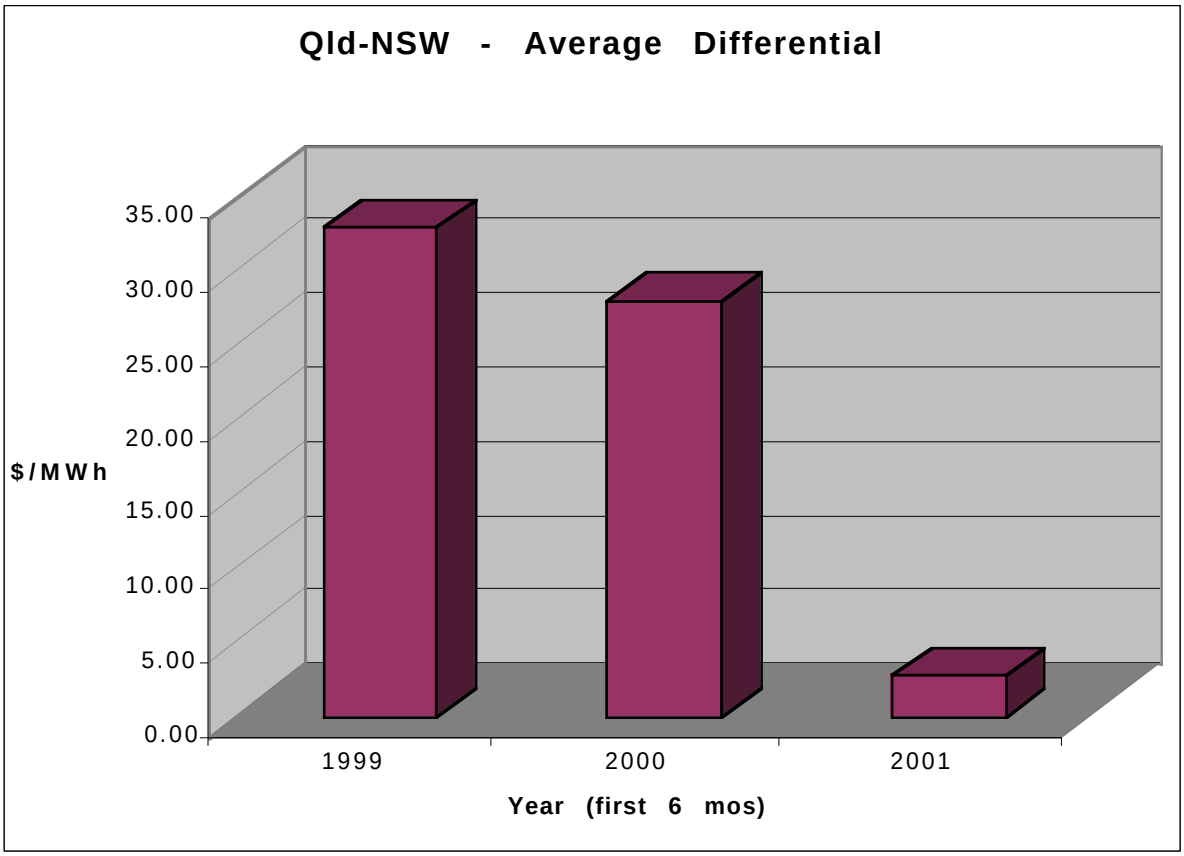
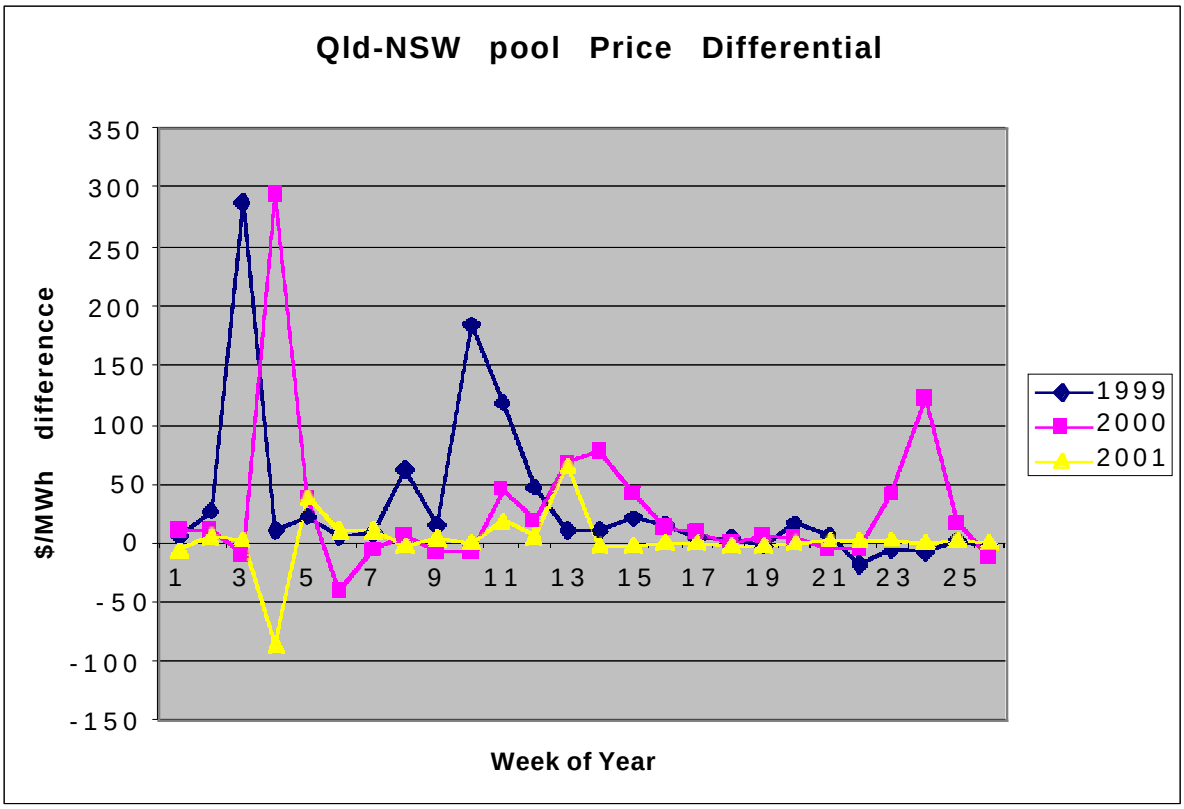
[2] See the Bardak discussion paper entitled "How to Succeed in the Electricity Business without really Generating — A Study of Capacity Withholding in the National Electricity Market", available for downloading from www.bardak.com.au.

The weekly variation in the pool price differential is shown in the second graph below. Note the marked reduction in price volatility in 2001 compared to previous years.

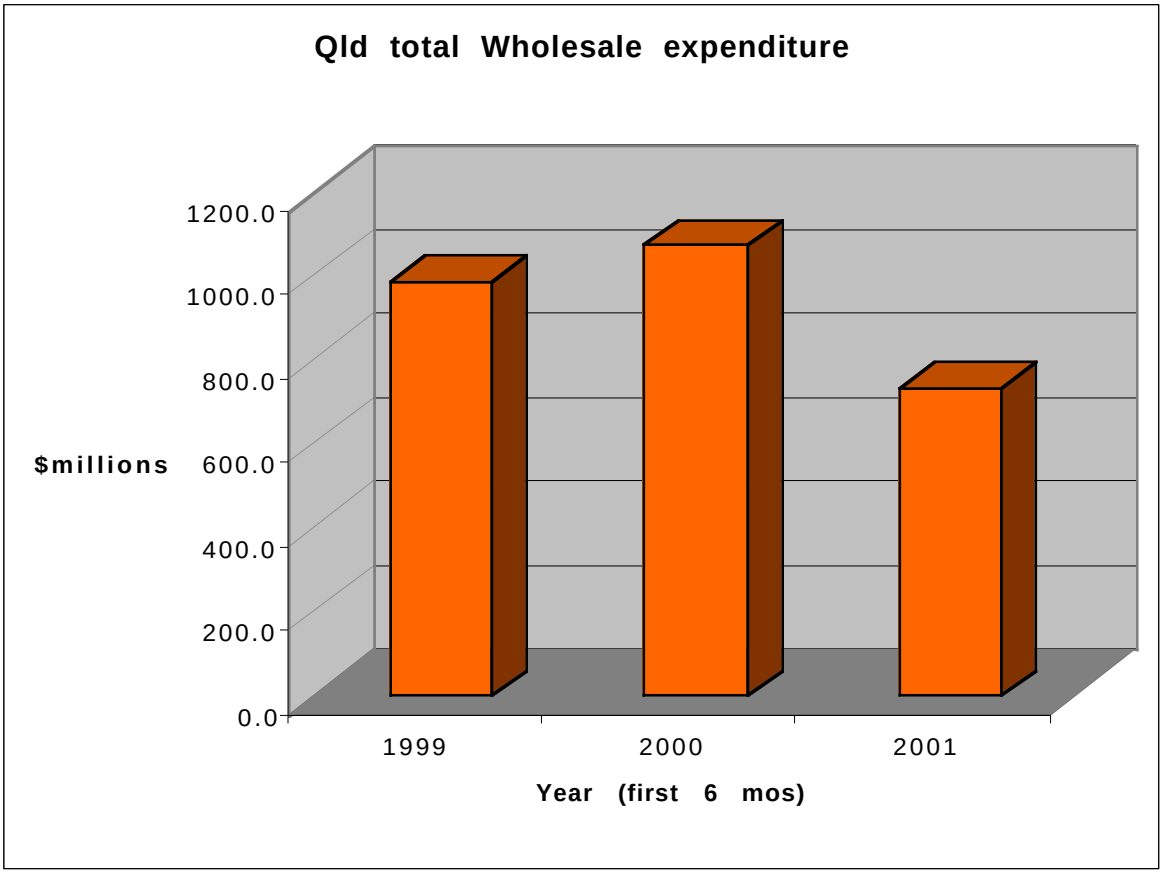

Qld-NSW - Average Differential
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
$/MWh
1999
2000
2001
Year (first 6 mos)


Qld-NSW pool Price Differential
350
300
250
200
150
100
50
0
-50
-100
-150
$/MWh differencce
1 3 5 7 9 11 13 15 17 19 21 23 25
1999
2000
2001
Week of Year

Note that there were still possibilities to generate substantial differentials when QNI was rated at 300-350MW or so in the early part of the summer period — even though Directlink was operating at the time — but as QNI capacity increased, the pool price differential was virtually eliminated (except for loss factor effects).

Care does need to be taken in inferring that all of this benefit finds it way to Queensland customers, but the reduction in pool price differentials is strongly indicative of real savings in electricity production costs, which should allow substantial economic benefits to customers.

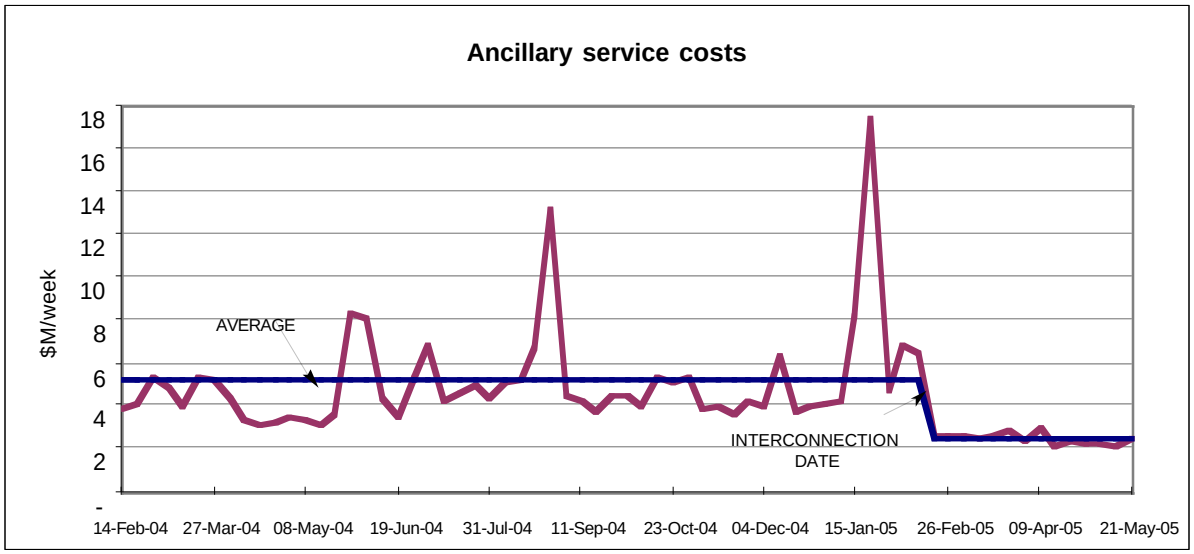
The estimated total expenditure on wholesale purchases from the pool in Queensland is shown in the graph below (estimated in that we have used a typical split of generation in the State for the first six months of previous years).



It can be seen that Queensland has spent almost $350 million less on wholesale power purchases from the pool in the first 6 months of 2001 compared to the same period of 2000.

In addition, figures have recently become available which show a very large

reduction in Ancillary Services charges since QNI was commissioned. The graph below shows the weekly AS charges in the early part of 2001.[3]



The savings due to this factor alone are running at $2.5-3.0 million per week — an annual saving of $130-150 million.

The magnitude of these savings to Queensland may be compared to the additional annual charges associated with QNI, which are of the order of $40 million per year to the two States combined. It recently was announced that QNI was completed ahead of time and well under budget. Compared to an initial estimated cost of around $450 million, the formal budget cost was $410 million and the final cost at completion only $350 million. The Queensland section, budgeted at $270 million, was completed for only $215 million.

The economic advantage of building the strong, regulated interconnection is apparent.

In addition, the delay in approving QNI from its original configuration and timetable has cost Queensland dearly, in that it had to commission some 750MW of peaking plant to fill the gap until QNI came into operation, not all of which will have a continuing role in power production in the State.

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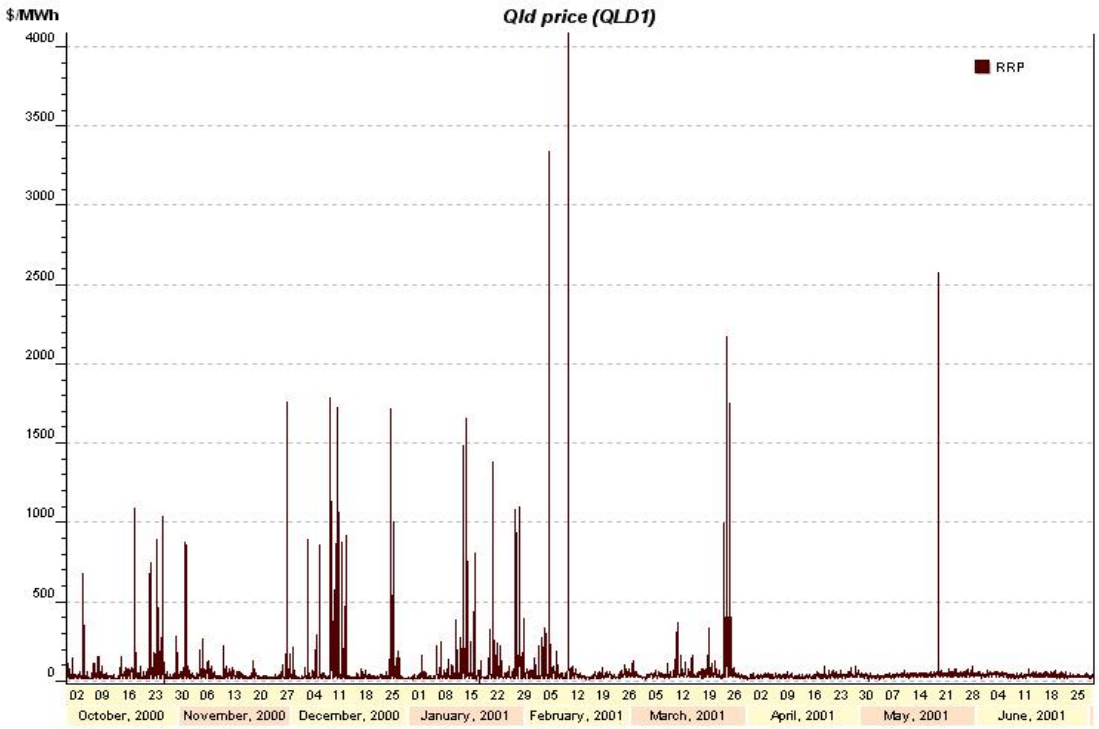
[3] This graph, and the next graph used in the paper were recently published by Powerlink Queensland, and the source is gratefully acknowledged.

While some other factors could have contributed to some of the savings, Bardak is of the view that it has primarily been the effect of QNI in limiting the opportunities for the Queensland generators to exploit their undoubted market power — as they did in 1999 and 2000 —that has led to the decline in Queensland pool prices and their reduced volatility.

The reduction in volatility of pool price in Queensland is especially important. As is becoming apparent in the Southern States, volatility adds to risk and increases the margins which retailers seek to add to pool/contract prices — a margin which is of the order of $30/MWh in the case of South Australian "grace period" customers. Anything which reduces volatility and risk will tend to lower such additional margins and is a further case in support of stronger interconnections in general and regulated interconnections as well.

The effect of QNI on Queensland pool price volatility is shown below, with the formal date of interconnection (QNI commissioned at 300MW) taking place on the 12th February. This graph also covers the latter part of 2000, when Directlink only was operating. It had no obvious effect in reducing price volatility.



Reduction in interconnector constraints, average pool price differentials and in pool price volatility also helps overcome the problem which the NEM has in contracting across interconnections — a particular problem for South Australia.

One could make a very reasonable argument on these figures that the expenditure on QNI has already been recouped in its first six months of its operation — a powerful argument in favour of regulated interconnections.

Implications for the SNI Interconnection and the National Electricity Code

By comparison with the QNI interconnection, the SNI (once called Riverlink and then SANI) became caught up in the contorted evaluation processes of the National Electricity Code.

After the initial unsatisfactory evaluation process for SANI in June 1998 — which showed deficiencies in the Code rather than in SANI itself — three years later it is still being evaluated by the NEMMCo/IRPC/IOWG series of committees, and has been delayed and delayed. It is — not unnaturally — opposed by generators and the promoters of "market" interconnectors, who do not want their existing scope to exploit the lax market rules and the dysfunctional market structure eroded.

Incredibly, the ACCC developed "Regulatory Test" does not allow the benefits of interconnections in reducing the scope for the exploitation of market power and the flaws in the trading system, to be brought into account as a benefit. This Regulatory Test is to be reviewed and it can only be hoped that this oversight is rectified.

By comparison with the Queensland-New South Wales situation described above, the pool price differential between South Australia and Victoria for the same first six month periods have been:

1999	$24.5/MWh
2000	$27.2/MWh
2001	$12.6/MWh

The differential in 2001 has been reduced by the rise in Victorian pool prices as there has been no fall in South Australian pool prices.

QNI added 500MW or some 8% of the Queensland peak load. SNI (plus its "market network provider" companion, Murraylink) will add about the same percentage to the effective installed capacity of South Australia.

If the experience of QNI is any precedent, the construction of SNI (and Murraylink) will substantially constrain the ability of the South Australian generators to exploit their existing high level of market power and reduce the differential between Victoria/NSW and South Australian pool prices and the volatility of these prices.

The reduction in constrained periods and volatility should exert a favourable affect on the extraordinarily high margins which apply in South Australia and facilitate the entry of more retailers into the State by reducing the risk of contracting over the interconnections. There is unlikely, however, to be much change in the level of Ancillary Services costs, as the present interconnection is probably large enough to capture the bulk of the benefits.

The control of market power has proven to be the "achilles heel" of compulsory, single priced pools wherever they have been tried — and ultimately led to the demise of these pools in the UK and California and is doing the same in Alberta.

It needs all the resources that can be marshaled against it to bring it under control, and the QNI experience in its first six months of operation provides evidence which cannot be ignored, that stronger interconnections between the

NEM Regions provides a potent force for reducing the impact of market power.

It is also a powerful endorsement of the concept of adequately sized regulated interconnections being able to reduce regional pool price differentials to just the effect of interconnector losses and to reduce pool price volatility — things not possible for unregulated interconnectors to achieve — and which bring real benefits to customers.

July 26th, 2001

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