Energy Reform
The way forward for Australia

A report to the Council of Australian Governments by the Energy Reform Implementation Group

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Dear Prime Minister,

It is with much pleasure that I present you with the final report of the Council of Australian Governments’ (COAG) Energy Reform Implementation Group (ERIG).

In undertaking its analysis, ERIG has made a number of key findings and recommendations:

- Australia is respected internationally for its past reforms in energy with these reforms producing one of the most competitive and efficient energy sectors in the world. However, while Australia has been well served by its energy sector in the past, ERIG considers that further reforms are necessary; both to maintain the productivity improvements of Australia’s energy sector and to better equip it for the future.

- Australia’s good performance in general masks significant jurisdictional variation.

- There is a strong case for the establishment of a more co-ordinated strategic approach to the development of the energy sector. This applies generally, but applies particularly in relation to transmission planning. In this regard, ERIG considers that the potential benefits from better coordinated development of the national transmission grid are sufficient to warrant the establishment of a strategic national planner under a reformed NEMMCO.

- Disaggregation and privatisation of government owned assets in the energy sector would address private sector concerns about barriers to entry and budgetary pressures which threaten to curtail the investment requirements of the sector. If full privatisation is not an option, privatisation of some elements of the contestable parts of the market (retail and generation) would help and initiatives to strengthen competitive neutrality safeguards are important.

- A number of improvements can be made to strengthen the national character of energy market governance. Specifically, I draw your attention to ERIG’s findings that: the Australian Energy Market Commission needs to be refocused and adequately funded; the establishment of a national energy market operator is an important longer term objective; and proposed changes to the governance of the National Electricity Market Management Company would make it more market oriented.

- Regarding energy financial markets, while ERIG found that they are generally maturing well, significant proposals are presented to improve interstate trading arrangements and market settlement. Important proposals are also presented relating to gas markets and removing barriers that discourage an appropriate demand management response within the sector.
In preparing this report, ERIG considered over 90 written submissions from a wide range of organisations and individuals across Australia. My Panel colleagues, Geoff Carmody, David Swift and Alan Rattray, and I have found strong and widespread support for further reform of Australia’s energy markets.

We consider that Australia is at a very important juncture in the evolution of its energy sector. Significant opportunities and challenges exist for governments to build upon the success of previous reforms to ensure that access to reliable and competitive energy continues to underpin wealth and job creation.

Our economic analysis (also supported by the recent Productivity Commission assessment of the NRA) indicates that the potential benefits in the electricity sector of further reform are in the order of $400 million per year over the medium term. These benefits translate into price reductions of around two to three per cent across states at the household level.

We strongly believe that these gains will be realised if governments implement the recommendations contained in this report as a mutually supporting package. We commend our report to you for the consideration of COAG.

Yours sincerely

Bill Scales AO
Chair
Energy Reform Implementation Group
12 January 2007
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ERIG’s Key Findings

Australia’s energy markets are world-leading. However, ERIG concludes further reforms would deliver more economic benefits. More market contestability, improved transmission planning and regulation, and facilitating efficient financial markets, are priority reform areas.

Making energy markets more contestable, efficient and well-governed

» Government ownership (especially in electricity) in some jurisdictions is a barrier to entry and is impeding competition. Budget pressures are limiting further government energy investment. Concerns about government businesses having an advantaged position are limiting private sector energy investment. Disaggregation, privatisation and improved competitive neutrality arrangements are needed. Retail price caps are barriers to entry and should be relaxed.

» Better governance, including reforms to National Electricity Market Management Company (NEMMCO) and the Australian Energy Market Regulator (AEMC), would improve efficiency.

» Competition and corporate law and regulation are appropriate and adequate, if applied equally to government and private businesses. No special energy sector rules seem needed at present.

Developing an efficient national transmission system

» Transmission markets also require reforms to ensure a fully national market focus is achieved.

» An efficient national transmission system requires improved locational signals to generators, better efficiency incentives for Transmission Network Service Providers (TNSPs), and proper national planning, coordination and system integration for national, market-wide grid development.

» A strategic national planner under a reformed NEMMCO, combined with reform of the currently flawed regulatory test, would ensure better evaluation of transmission investment options.

Facilitating efficient financial markets

» Mechanisms supporting interstate trade need to be improved. These include: resolving inefficiencies in the operation of the Snowy region, improving firmness of inter-regional trading rights, and contracting relevant generators to support inter-regional flows.

» Settlement of the spot and contract markets need to be better integrated.

» Additional key areas for reform are: developing gas financial markets, facilitating the development of a more effective demand response, improving the effectiveness of strategic planning and implementation, and developing the market design to better deal with the trend towards consolidated vertically integrated national players.

Estimated Economic Benefits of Reform

» These reforms, taken as a whole, could increase real Gross Domestic Product (GDP) by about $400 million per year, with retail energy price reductions of about 2%.
Executive Summary

Background

Access to competitively priced and reliable energy underpins the competitiveness of Australia’s export industries, is a crucial input for the domestic economy and a key enabler for almost every economic activity. In 2004-05, the electricity sector contributed 1.4 per cent to Australia’s GDP.

Energy market reforms over the past two decades have played a significant role in facilitating improvements in productivity and have underpinned Australia’s impressive economic growth. For a large component of the National Electricity Market (NEM), implementation of National Competition Policy has led to the disaggregation of the previously vertically integrated electricity utilities into their respective supply chain elements and moved Australia towards independent, decentralised decision-making in the energy sector. In the 1990s, the generation and retail elements were separated and exposed to some degree of competition through the introduction of a gross pool electricity market.

The increase in the level of independent, decentralised decision-making in generation and retail in the NEM, driven by an increase in the extent of competitive forces, has been the primary driver for the efficiency gains to date. The increase in the level of competitive pressures has increased the utilisation and performance of generation assets and lowered operating costs and driven real efficiency gains through the NEM-wide dispatch of generation. Retailers have also become more responsive to customers and prices for most customer groups have declined over the past decade.

Energy market reforms by the year 2000 were estimated by ABARE to have resulted in an increase in national income of $1.5 billion with Australia having some of the lowest electricity prices in the developed world. Industrial and household electricity prices are 38 per cent and 31 per cent respectively below the average across the International Energy Association (IEA) member countries.

The fact that these reforms have produced one of the most competitive and efficient electricity markets in the world has been recognised by the International Energy Agency (IEA). The IEA observed in its review of Australian energy markets that “Australia was one of the pioneers in energy sector microeconomic reform and should be commended for its vision and implementation of a liberalised (electricity) market. Australia now has one of the most transparent and competitive electricity markets in the world and could serve as a model for other countries” (IEA 2005).

However, improvements in the performance of the Australian energy sector over the past two decades mask two important realities. First our past performance tells us nothing about our full productive potential in the energy sector. ERIG has attempted to determine how the energy sector can reach its full productive potential and commissioned modelling to help understand the likely benefits which can flow to Australia if it can do so. Second, average Australia wide performance masks significant differences in performance between the states.
ERIG Terms of Reference

On 10 February 2006, the Council of Australian Governments (COAG) agreed to establish an Energy Reform Implementation Group (ERIG) to review certain elements of the operation of Australia’s energy sector and to suggest further reforms, where there is a case for them, supporting more efficient energy markets.

ERIG was asked to report before the end of 2006 on reform recommendations for:

» achieving a fully national transmission grid including the most suitable governance and transitional arrangements having regard for COAG’s objective of achieving a truly national approach to the future development of the electricity grid, the legitimate commercial interests of asset owners, and the need to promote investment that supports the efficient provision of transmission services;

» any measures that may be necessary to address structural issues affecting the ongoing competitiveness and efficiency of the electricity sector; and

» any measures that may be necessary to ensure there are transparent and effective financial markets to support energy markets.

ERIG Panel members were appointed in June 2006 and ERIG began its work during that month.

ERIG’s Approach

Consistent with the focus of the current National Reform Agenda (NRA), ERIG’s review focuses on the economic efficiency of the energy sector, particularly the electricity sector.

ERIG considers that the goal for Australia’s energy sector should be that:

» Existing energy assets should be operated at ‘best practice’ levels (maximising technical/productive efficiency);

» Investments in energy assets should generate competitive returns (maximising capital efficiency);

» The allocation of resources to the energy sector should be ‘just right’ given competing demands for scarce resources (maximising allocative efficiency);

» Over time, the relevant market and economic signals and incentives should allow all of these efficiency dimensions to be sustained - the right amounts of investment at the right time – and should encourage innovation in the energy sector (maximising dynamic efficiency); and importantly

» These efficiency dimensions should be seen from a national perspective.

Governments are held responsible for ensuring energy is able to be supplied efficiently and as reliably as possible – it is an essential service. ERIG believes that the most efficient roles for governments in securing these outcomes in the energy market are:
to ensure appropriate levels of supply reliability standards are set, preferably uniformly across Australia;

- to make sure that institutions, mandates and governance arrangements are structured to drive broad efficiency outcomes;

- to eliminate barriers to entry where markets can be contestable;

- to ensure that markets are well designed and efficient; and

- for regulated parts of the market, to make sure that regulation tries to replicate the operation of a competitive market so that the regulatory incentives lead to the most efficient outcomes possible.

In undertaking its work, ERIG focused on the extent to which the existing structures and governance arrangements in the energy market are sufficient to support a national energy market across Australia, thereby delivering greater efficiency and lower costs, and are sufficiently flexible to enable rapid responses in an uncertain environment.

In this context, ERIG notes that the energy market in Australia is entering a period of significant uncertainty. The industry will, at some stage in the future, need to respond to the complex risks associated with the greenhouse challenge. Responding to these risks will be even more important given the size of the investment required to underpin future energy demand.

Australia’s energy demand, and the investment required to sustain it, are growing. ABARE estimates that the total amount of electricity generated Australia wide will grow at an annual average rate of 2.1 per cent over the medium term. As a result, total generation output is projected to increase from an estimated 245 TWh in 2005-06 to over 600 TWh by 2049-50. An additional 100 GW of additional capacity will be required to meet this increase - more than twice the level of capacity currently installed Australia wide. The Energy Supply Association of Australia (ESAA) has estimated that, by 2030, additional installed generation capacity to meet Australia’s electricity demand growth will cost at least $35 billion. Further, the Energy Networks Association (ENA) has indicated that each year energy network businesses (gas and electricity) undertake investment of around $5 billion per year.

ERIG has found that more can be done to improve the efficiency of Australia’s energy sector. ERIG considers that Australia’s energy market arrangements could be made much more flexible to allow for more rapid responses to these changing circumstances.

Given the right market and economic signals and appropriate governance arrangements, private sector investors in energy are inherently more capable of responding rapidly to altered market circumstances than public sector investors – and in this part of the economy, ERIG has found them very willing to do so.

In addition, the current, largely state-by-state approach, to considering energy issues still permeates the energy system. While serving Australia reasonably well in the past, this ‘state based’ institutional and regulatory framework is unlikely to be able to serve Australia as well into the future. Planning of Australia’s electricity transmission network is a good example of where it has been possible in the past to consider matters on a state-by-state basis, but where a more national approach to planning is likely to be required to maximise the efficiency of the energy sector in the future.
ERIG considers more can be done to encourage the development of a national energy market. ERIG believes that all elements of the energy system – generation, transmission, distribution and retail – will be dominated by organisations that, for effectiveness and efficiency reasons, will want to operate in Australia as if it were one national market. ERIG strongly believes that securing Australia’s energy future will necessitate the development of a consistent, coherent and national approach to all elements of energy policy, regulation, governance and practice.

Australia’s national energy market should be guided, at the highest level, by broad policy objectives covering efficiency and reliability that are set nationally.

ERIG concludes that Australia does not yet have a fully national energy market. For example:

- there are at least five separate market operators operating gas and electricity markets across Australia (NEMMCO, VENCorp, REMCo, GMC and the IMO). ERIG believes that, ultimately, there should be a single national energy market operator for Australia;

- the Australian Energy Market Commission (AEMC) has been established as the national rule making and market development body, but ERIG has very serious concerns about its funding, ability to act strategically and to manage its workflow, and the limits to its national reach;

- Australia is moving towards a single regulator, the Australian Energy Regulator (AER), although full implementation of that policy has not yet been achieved;

- numerous state derogations from the national rules and regulations covering energy exist, creating a different legal and regulatory framework for the energy market in each state;

- transmission planning and decision-making is still regionalised with strategic national planning to optimise system-wide investment not occurring effectively;

- each state has its own requirements in relation to retail competition and licensing of retailers;

- market arrangements for trading in financial markets between regions is more difficult and risky than it needs to be; and

- where governments remain as major supply-side participants in the industry by owning and operating substantial energy assets, the impartiality of objectives and mechanisms to achieve a national energy market, including through the Ministerial Council on Energy (MCE), are likely to be comprised.

Ensuring competitive, efficient and national energy markets is even more important at a time when substantial investment is needed in energy supply infrastructure to ensure sufficient supply of competitively priced and reliable energy to meet growing demand into the future. Ongoing reform of the energy sector is also important because of the economy wide benefits that it generates.
ERIG’s Key Findings

Market Structures

ERIG’s benchmark for encouraging good market outcomes, especially in contestable markets such as generation and retail, is competition. Competition has been proved to be able to deliver the highest level of output at the lowest cost that is sustainable over time. ERIG has identified three threats to competitiveness and efficiency currently affecting Australian energy markets: barriers to market entry; governance improvements and regulatory inadequacy.

Barriers to market entry

ERIG has been struck by the consistent refrain that ‘government’, particularly some state governments, are a barrier to private sector entry into energy markets. Government policy and government ownership of competing businesses are the two sources of such barriers.

Differences in policy on greenhouse gas abatement arrangements at the national and state level are a key source of investment uncertainty. Government regulation of energy prices (e.g., retail price caps) is also a significant barrier to private entry into energy supply markets where price caps are binding and their existence constrains the emergence of retail competition. Use of government-owned assets to drive other government policy objectives is a barrier to entry in some cases.

There are budget pressures that effectively constrain governments from energy market investments. Involving the private sector in the supply of energy assets is likely to be a plus for budget-pressed states. Allowing the private sector to provide capital for energy supply infrastructure frees up scarce government resources for investing in other important social priorities, like hospitals and schools.

Government ownership in some jurisdictions causes serious concerns about competitive neutrality. Perceptions held by private investors that there is no ‘level playing field’ between publicly owned and privately owned assets directly threatens full market contestability.

The evidence suggests barriers to private entry can take different forms in different states.

In NSW, the dominance of government-owned energy businesses, plus evidence of intermittent but persistent market power, plus the failure to attract new private sector entry despite price signals for it, suggests that private investment in the energy sector may be delayed or prevented compared with what would occur in a fully contestable market.

In Queensland, the problem is different. Government investments, if anything, appear to be undertaken too soon, because of official concerns about reliability (and possibly other state development objectives), potentially stranding some private investments.

On the basis of analysis provided by one consultant engaged by ERIG, and by considering the evidence in submissions and other publicly available research, ERIG is of the view that there is an accumulating body of evidence suggesting that recent productivity gains (after market start) within the NEM have been quite different between jurisdictions within the NEM. This evidence is based on data which ERIG accepts and fully understands is
subject to a number of qualifications. Nevertheless, taking all the evidence as a whole, including broad productivity trends, ERIG believes the weight of evidence suggests that the private ownership model is the most efficient model for the delivery of electricity. It delivers outcomes closest to the competition ideal and the best outcomes for energy users.

ERIG concludes that disaggregation of significant retail and generation portfolios, followed by privatisation, is the most effective solution to most of these problems and would increase the overall efficiency of Australia’s energy sectors.

ERIG recognises there are political issues associated with privatisation for some states. However privatisation of even one element of the contestable energy chain would assist in driving more competitive outcomes, improve efficiency, and therefore achieve better outcomes for users of energy. For example, ERIG believes that the recent sale of the Queensland Government’s retail energy assets will act as a driver of efficiency in the supply of energy in that state.

ERIG notes that some state and territory governments have ruled out privatisation of some or all of their currently owned energy assets at this time. Who owns and operates certain assets used to provide services to the people of a state or territory is a matter for governments.

If governments wish to retain the ownership of their energy assets, then ERIG considers that initiatives to improve competitive neutrality should be implemented immediately to place government businesses, as far as is possible, on the same commercial footing as their private sector counterparts. That said, ERIG considers that the playing field between public and private sector businesses cannot ever be completely level.

For those governments who decide to retain their existing energy assets but seek to encourage the private investment for new investment, ERIG considers that clear and unequivocal signals about their intention to do so is fundamental. Without such signals, private investor perceptions of ‘sovereign risk’ at best adds to hurdle rates of return (and therefore energy costs) before investment occurs, or, at worst, may delay or prevent desirable energy investments from taking place.

The Government of Western Australia appears to be the most advanced within Australia in following this ‘clear signal’ strategy. Placing a cap on generator expansion and other limits on the government owned market incumbents in the Western Australian energy market appears to have sent a positive message to the private sector about the intentions of the WA Government.

For jurisdictions where signals are less clear (such as in NSW and to a much lesser extent Queensland), industry participants strongly asserted that continued public ownership of a large amount of a state’s competitive energy assets is a significant impediment to future private investment in those states. Private sector operators cited government ownership, and particularly the apparent willingness of government owners of these assets to be guided in their investment and operational decisions by drivers other than purely commercial considerations, such as political factors and/or desires for regional development, as one of the biggest impediments to private investment in the energy sector in those states. Perceptions, strongly held, whether well founded or not, can be real barriers to market entry and timely capacity expansion.
ERIG is not suggesting that some private investment will not occur under these less than ideal circumstances. But this private investment is more likely to require special, case-by-case incentives or even specific guarantees before this private investment is committed. ERIG does not regard this as consistent with an efficient investment and energy market where private investors are continually seeking out sound investment decisions that will meet the needs of their shareholders and potential customers, and rapidly and efficiently investing to take advantage of these emerging opportunities.

ERIG considers that there is a clear willingness of the private sector to invest where it is faced with a level playing field and sustained demand for additional investments in energy assets. These considerations together, in ERIG’s view, establish a strong case for making sure that signals are sent clearly and unequivocally to the market that future investment within the NEM and the Wholesale Electricity Market (WEM), will be for the private sector to undertake.

On retail price caps, ERIG notes that retail price controls have meant that many consumers do not receive accurate pricing signals about the cost of using electricity, particularly at peak times. As a result, the demand side of the NEM is relatively inactive and this has significant implications for the efficient operation of the electricity market. In addition, price caps are a barrier to entry.

ERIG endorses the commitments made by state and territory governments to remove retail price caps after competition exists in electricity markets. However, ERIG concludes that there is an inherent contradiction between (i) waiting for competition to emerge before removing price caps, and (ii) the fact that binding price caps themselves constitute impediments to competition. ERIG considers this contradiction should be reviewed and resolved so that faster progress can be made in this area.

ERIG also considers that governments should conduct a detailed review of arrangements for community service obligations in the energy sector with the objective of identifying non-distorting, transparent and targeted delivery mechanisms to replace the ‘blunt instrument’ of retail price caps.

**Governance improvements**

ERIG believes that improvement in the governance arrangements that support Australia’s energy markets is a critical pre-condition for the continued improvement in the performance of Australia’s energy sector.

Good governance principles—ensuring no conflicts of interest, clearly allocating responsibilities, getting incentives ‘right’—are relatively easy to enunciate, but are sometimes difficult to implement.

Australia’s energy market governance arrangements have been improved somewhat as a result of reforms implemented since the 1990s. However, ERIG believes that further refinements can and should be made to support the emergence of a national and efficient energy market in Australia.

ERIG strongly believes that single Australia-wide, energy market-wide, independent (and preferably separate) institutions covering planning, market operation, market regulation and rule making are urgently required and would be the logical evolution of current market governance arrangements.
Privatisation of remaining government-owned electricity assets would eliminate potential conflicts of interest and facilitate improved governance arrangements by removing intra-market jurisdictional biases.

Sharpening the separation between the role of the MCE as the peak policy-making body, and the bodies responsible for planning, operating, rule-making and regulation of Australia’s energy markets, would improve governance, including by ensuring the independence of market operators from governments. Increasing the influence of the Commonwealth or COAG in the oversight and development and monitoring of Australia’s energy policy and clarifying and strengthening the role of the Commonwealth Government within the MCE would help as well.

The AEMC is in need of substantial governance reforms. It needs to be adequately and transparently funded, preferably by the Commonwealth Government, and to have more control over its own work programme, subject to being required to develop rules that enhance market efficiency. It needs a full time Board of Commissioners.

Australia’s electricity market rules are not uniformly applied across Australia because of numerous state derogations. This is inconsistent with ensuring a national, efficient, energy market. Uniform rule application should be applied as soon as possible, with annual independent reviews of progress.

NEMMCO’s governance would be improved by providing for more independence in relation to Board appointments, and more industry representation on its Board to further improve its service culture. These reforms are crucial pre-requisites for other reforms recommended by ERIG potentially involving NEMMCO, including in relation to transmission planning; more efficient financial market settlement arrangements; and the feasibility of a single energy market operator.

Importantly, ERIG believes that, ultimately, a national energy market operator should replace the separate operators for gas and electricity. This should be adopted as a longer term governance objective.

**Regulatory inadequacy**

ERIG has been asked by COAG to consider whether or not the regulatory safeguards protecting markets from uncompetitive behaviour are adequate in the case of Australia’s energy markets.

An important issue concerning policy makers and the industry is the extent to which vertical integration, particularly between energy retailers and electricity generators, is inherently anti-competitive and therefore should be prevented.

ERIG notes that there are strong commercial incentives for vertical mergers between contestable sectors (generators and retailers) to form what are sometimes described as ‘gentailers’. These incentives arise from the ability of vertical integration strategies to deliver economies of scale and scope and a physical hedge against pool market price risk. ERIG notes that within the contestable segments of the market there may be continued incentives towards vertical integration between generation and retail.

ERIG believes that vertical integration is not anti-competitive *per se*. But anti-competitive problems may arise where it is associated with excessive horizontal aggregation. ERIG can
find no evidence, at this time, that the integration (which in general has been partial anyway) between energy retailers and electricity generators has been anti-competitive.

ERIG does not rule out the possibility that this could become an issue in the future. But were it to become the case, it would be because a horizontal aggregation problem would have arisen. At this stage, ERIG considers the Trade Practices Act 1974 (TPA) to be the appropriate vehicle for determining the competition impact of mergers and acquisitions in the contestable segments of the electricity market, and, properly applied, it appears adequate to the task at the present time.

Where mergers involve contestable market entities (generation or retail) and ‘natural monopoly’ entities (transmission or distribution), ERIG concludes that there is a legitimate cause for concern about regulatory adequacy. Natural monopolies, by definition, possess market power. Mergers between natural monopolies and contestable market entities may allow that power to be exercised, in non-transparent ways, undermining competition. Consistent with that principle, ERIG agrees that governments should promulgate cross-ownership rules proscribing such mergers between generators and transmission as soon as possible in the interests of investor certainty. These rules should comply with competitive neutrality principles.

A similar argument, in principle, applies to distribution/retail mergers, however the market trend seems to be that, when privatised, the owners of these assets are separating these two types of businesses anyway.

ERIG has received somewhat conflicting claim about the application of the TPA to government owned businesses. If the TPA does not apply equally to both government and private businesses, competitive neutrality is undermined and regulatory inadequacy exists. If this is the case, ERIG strongly believes that this must be rectified so that the TPA fully applies to state owned corporations.

ERIG notes further evidence that the Corporations Law does not apply equally to state government and to private businesses, because of ‘carve-outs’ in some states limiting or excluding the application of the Corporations Law to the former. This appears to significantly undermine competitive neutrality and market efficiency. ERIG strongly believes that this must be rectified so that corporations law fully applies to state owned corporations. ERIG concludes that such ‘carve outs’ should be removed by appropriate state legislation as soon as possible.

A Fully National and Efficient Transmission Grid

ERIG was asked to examine Australia’s transmission arrangements. This included examining the most suitable planning and governance arrangements for creating a fully national transmission grid within the NEM, having regard to COAG’s objective of achieving a truly national approach to the future development of the electricity grid.

The development of an economically efficient and fully national market is not solely a matter for transmission planning and investment. The development of such a market is also dependent upon competitive markets in each region, open access on a level playing field across the market and well functioning financial markets.
It is also clear that the development of the transmission system cannot be separated from the development and operation of the overall power system or from operation and investment in generation, or from decisions by customers and the broader energy market.

The timely and efficient delivery of transmission services is crucial to enabling the electricity system to meet the emerging challenges posed by Australia’s future energy demands. It is, however, also important that there is efficient investment in both the level and location of generation to meet customer demand. In addition to the discussion earlier of the likely future demand for investment in generation, estimates also suggest that around 1,000 MW of additional generation capacity is required every year for the next ten years to meet demand growth. To maintain and build on the benefits of the reforms to date, this investment and the related transmission investment will need to deliver an efficient overall power system.

ERIG considers that its terms of reference do not mean that the national grid should be totally unconstrained and completely ‘free flowing’. Rather, ERIG considers that at certain times some level of congestion may be efficient and that transmission congestion does not of itself signal market and investment inefficiency. In fact, the NEM has performed reasonably well to date and ERIG considers that the current level of transmission and interconnection investment is reasonably appropriate for today’s level of installed generation capacity and peak demand.

In this context, ERIG considers the key policy question to be addressed is how to ensure the economic regulatory regime, incentives, pricing and approvals processes all work together with the overall planning and governance structures to achieve an efficient mix of generation and transmission investment into the future which will provide the lowest delivered cost of energy to consumers, across the whole of the NEM.

**Shortcomings of the current arrangements**

ERIG has identified shortcomings in three critical elements for achieving an efficient mix of generation and transmission investment across the national grid:

- the need for commercial incentives on generators to locate efficiently in respect to the transmission grid, primary energy sources and load locations;
- the need for improved incentives for both efficient operation of the existing transmission system and efficient investment in a whole of NEM market context; and
- a requirement for coordination of investment in the transmission system on a national basis.

While the current level of transmission investment is reasonably appropriate, investment decision making is biased toward investment within each state rather than, where it is efficient to do so, having a true national character. The lack of clear incentives or mechanisms to ensure the efficient ongoing development of the national transmission system leads ERIG to the conclusion that opportunities for efficient investment opportunities have been missed in the past. More importantly, substantive improvements need to be made to ensure the future challenges can be efficiently met.
The way forward

The AEMC review into congestion management is an important opportunity to improve the incentives on generators to locate and operate efficiently. This review needs to take account of the allocative and dynamic efficiency gains from doing so. The terms of reference for that review, however, may hamper the AEMC in delivering the most effective solution.

The development of market based incentives on TNSPs by the AER is also important and should be continued to drive overall efficiency gains. The right drivers on TNSPs behaviour are also vital in achieving the national market objective.

ERIG has considered the role and function of the Regulatory Test as it now applies in the evolving regulatory regime. The investment decision making criteria in the Regulatory Test are appropriate and should be retained, however the two criteria for investment should be amalgamated. The Regulatory Test itself, however, does not currently perform the role of a test and its links to the regulatory regime are tenuous at best.

ERIG considers that there is merit in replacing the Regulatory Test with a two step process to guide efficient transmission investment as follows:

» the establishment of a National Transmission Network Development Plan (NTNDP) aimed at delivering an integrated, national plan for the longer term efficient development of the grid on an integrated, national basis; and

» a project by project assessment should be made and stakeholders consulted prior to any major network augmentation project being constructed which demonstrates that the most efficient alternative, whether network or non-network, has been adopted to meet reliability standards and deliver market benefits while fitting within the umbrella of the NTNDP.

ERIG also considers that there would be efficiency gains from removing current differences in the reliability and planning criteria between state jurisdictions and disparities in how they are applied. A consistent national framework for these standards could improve certainty and investor confidence as well as providing a level playing field across the NEM.

ERIG considers that the potential benefits from better coordinated development of the national grid are sufficient to warrant the establishment of a national planning function.

After reviewing a number of options, ERIG concludes that the planning model could be either:

» a National Transmission Planner – involving a strategic national planner to collate, analyse and disseminate information and deliver strong and well informed independent advice on efficient investment across the NEM as a strategic national plan; or

» a National Transmission Service Procurer – involving the establishment of a NEM-wide, not-for-profit corporate entity responsible for undertaking national planning, making augmentation investment decisions and procuring those services either by negotiation or tender.

ERIG recommends the implementation of the first option, the National Transmission Planner, because it is consistent with the proposed incentive based regulatory regime and is commensurate with the scale of the identified shortcomings in the current arrangements.
The National Transmission Planner model as proposed would maintain the current accountabilities of TNSPs for investment and operating performance and seeks to complement the existing regulatory arrangements. It would also provide a focus for national development of the transmission system as a whole which is not currently being delivered. Arguments that only a small proportion of current network projects have an inter-regional impact are, in ERIG’s view, based on a narrow, technical view of the development of the network rather than from the perspective of efficient market outcomes.

ERIG considers that further work is required to developed detailed arrangements to implement the new national planning function. This report outlines recommendations for a review by the AEMC to further detail the planning framework and to rewrite relevant sections of the National Electricity Law (NEL) and Rules (NER). Whilst the new regime would need additional provisions for planning, for investment decision making and for the implementation of the new National Transmission Planner, a number of existing provisions would be made redundant. The National Transmission Planner would replace the role of the Inter-regional Planning Committee (IRPC) and the NTNDP would replace the Annual National Transmission Statement (ANTS) process. Under ERIG’s proposals, the implementation of the NTNDP and the arrangements for a Project Assessment and Consultation would replace the current Regulatory Test.

The reform of NEMMCO proposed by ERIG provides an opportunity for the new national planning function to be incorporated within that body. The function if incorporated within NEMMCO would benefit from some organisational synergies and cost savings. However, the function would need to be established anew with a stronger focus within NEMMCO on involving all parties in the development of national plans. It is therefore contingent on implementation of the recommended reforms to NEMMCO.

ERIG considers that the development of a NTNDP is not possible without understanding and analysing potential developments in the competitive sectors, the nature and location of likely generation investments and the location and growth of customer load. This planning requires a range of inputs and oversight from a range of industry participants and stakeholders and this input is seen as essential to the plan’s quality and usefulness.

ERIG considers the proposed national transmission planning regime should be reviewed within five years to consider whether the incentive regime on TNSPs together with the coordination and advisory function of the National Transmission Planner have produced efficient outcomes or whether the role of the National Transmission Planner should be extended to provide it accountability for decision making and procurement of transmission services.

Arrangements in Western Australia are different from those that apply to the NEM and have only been established for a relatively short period of time. However, Western Australia operates a transmission network over a wide area and in a competitive market context. As such, the key principles for the efficient development of the Western Australian power system should be similar and ERIG has recommended exploring the potential to use national institutions for its development, operation and regulation and to apply the general principles recommended for the NEM in Western Australia.
Energy Financial Markets

ERIG has been asked to examine ‘any measures that may be necessary to ensuring there are transparent and effective financial markets to support energy markets.’

Transparent and effective energy financial markets provide instruments for market participants to manage risks. More importantly financial markets are a critical element in fostering efficiency. Financial markets also provide the signals for investment.

Australia’s energy financial markets comprise capital markets, spot markets and contract markets. ERIG has focused on electricity and to a lesser extent, gas markets. In terms of electricity, the primary focus has been the NEM (the interconnected states of Queensland, NSW, Victoria, SA and Tasmania as well as the ACT). However limited commentary is also provided in regard to the newly created electricity market in WA.

Overall the evaluation by ERIG of the NEM is positive in relation to financial markets, notwithstanding that there are areas where useful reform should proceed. Gas financial markets by contrast are still maturing and lacking effective spot markets (except in Victoria).

Capital markets and investment

A survey by KPMG of investors commissioned by ERIG found three major impediments affecting investment and efficiency:

- government ownership is a significant impediment to investment in the electricity sector in some states;
- investors regard the implementation of full retail contestability (FRC) in those states which have not already done so as being important to the development of an efficient financial market for energy. The progressive removal of retail price caps or the progressive raising of price caps would, in their view, stimulate competition and capital markets thereby lowering prices for end consumers; and
- investors have indicated that they are factoring in a carbon price signal to their investment planning and decisions but are uncertain about its nature and timing. Investors view the existing range of government emissions abatement schemes and policies as fragmented and inefficient. This is argued to lead to a lack of liquidity and competition and is brought to the attention of governments.

Contract trading in the NEM

Traded financial markets in energy are evolving in a generally positive way. There seems limited (if any) role for governments in traded financial markets per se other than ensuring expeditious improvements as required in the underlying spot market.

Market liquidity has strengthened in the more visible markets such as the Sydney Futures Exchange (SFE) and brokered Over the Counter (OTC) markets and the aggregate volume of trading has trended up to about 1.3 times system demand. This healthy trend should be supported wherever possible when rule changes are considered.

However, the liquidity and depth of the financial market varies across regions, across time and over products. There are specific gaps in the liquidity and depth of products in South
Australia and Tasmania, gaps in products to manage varying customer demand, and according to some participants, in short term products.

To enhance financial market trade and to deal with evolving trends in the market, such as consolidation and vertical integration, it would be appropriate to attempt to develop a mechanism in relation to South Australia and Tasmania to facilitate trading of these regions without compromising existing arrangements and the basic NEM design integrity. Although ERIG has not had time to address this area in detail, it is believed that such mechanisms may be practical. Similarly, the industry is encouraged to expedite the development of simplified tradable products to manage varying customer demand.

Financial market trading activity has increased in the face of the limited vertical integration which has occurred to date. Having said this, there is a need for a watching brief to monitor market developments over time to assess this impact. The key strategic consideration is whether the market design and rules should evolve to better manage the evolution of the market to a lesser number of vertically integrated players.

Institutional arrangements and market design
ERIG has identified a weakness in the development and implementation of key strategic policy in the energy market. In addition, industry should have a greater role in the oversight of a reformed NEMMCO’s market operations functions through the formation of a market operations panel.

The energy-only design for the NEM has been effective and should be retained. The material progress represented by the WEM is also acknowledged and supported, however some improvements are proposed for the mechanisms of the capacity market.

Inter and intra-regional trade
There is a need for refinement of intra-regional location signals to enhance efficiency. However full nodal pricing should not be considered as a solution in part because of the adverse effects this would have on energy financial markets. Signals are also required for embedded generation, and firm demand side within the distribution system or generators connected to transmission to receive the benefit of avoided transmission investment and where relevant, credit for supporting transmission operations. Some form of transmission pricing to signal the locations where generation is able to best support transmission should be considered.

The mechanisms supporting inter-regional trade are not working efficiently and adding to risk premiums in the market. The rationalisation of the Snowy Region is a key priority and will also enhance the effectiveness of financial markets. There is a need to improve the design of the instrument supporting inter-regional trade, particularly, the settlement residue auction process by creating firmer transmission rights. The benefits of this measure, based on recent history, would be around $100 million per year for NEM customers.

Settlement of the spot and contract markets and credit
Under the current NEM design, spot and contract markets are largely settled separately. This results in the duplication of credit requirements in the spot and contract markets. This situation increases systematic risk, creates timing differences, increases barriers to entry and
is increasingly important with the privatisation of retail businesses in Queensland. Proposals are presented to advance the integration of spot and contract markets. In addition, the removal of barriers to the increased use of SFE settlement to offset spot market settlement is proposed.

Demand response
As noted earlier, the demand side in the NEM remains relatively inactive compared with its potential. Achieving its potential would drive major benefits in the NEM.

The commitments made by state and territory governments to remove retail price controls will be helpful when implemented in supporting cost reflective prices and demand response. The work program of the MCE on demand side response and the progressive rollout of electricity smart meters from 2007 provides a further building block and is supported. However, smart meters alone would not be sufficient to create an efficient demand side response.

In the large customer segment, while progress in demand side management (DSM) has been only fair, there seems to be little basis for a policy response as the market is working to a degree. However significant participation of small customers in DSM initiatives can not be expected without automation. For this reason, the development of automated DSM for small and medium customers is required to facilitate DSM but may not develop without initial sponsorship by governments and supportive changes in the institutional arrangements to ensure that market mechanisms can work in practice.

Government and regulatory issues
There are government and regulatory issues in a number of areas where the Commonwealth through the Australian Securities and Investments Commission (ASIC) could consider action to better support and remove barriers to the development of more efficient financial markets in electricity and gas, thereby fostering reduced risk premiums.

Furthermore, the removal of the Electricity Tariff Equalisation Fund (ETEF) in NSW accordance with the published timetable, as well as the removal of the Long-Term Energy Procurement (LEP) in Queensland would enhance financial market trade and efficiency.

Gas financial markets
The Gas Market Leaders Group (GMLG) recommendations offer worthwhile progress and are generally supported by ERIG. The establishment of a gas spot market and a gas market operator, with ultimately a National Energy Market Operator, is strongly supported by ERIG.

Greater standardisation of gas market structures, gas market processes, pipeline access and supply points for pricing across the market is required to enhance gas financial trade. This is becoming of increasing importance given the trend towards the development of gas fired generation and to foster gas retail competition. Finally, further work is required to assess the upstream areas of acreage management and joint marketing.
Other Matters

Greenhouse gas abatement measures & renewable energy

In the context of considering investment impediments, ERIG was struck by the significant concerns raised by market participants about market uncertainty in relation to possible future greenhouse gas abatement initiatives. Market participants have indicated to ERIG that greenhouse risk constitutes one of the most important barriers to investment in the energy industry, particularly to new base load coal investments. ERIG notes that most market participants desire a coordinated and sustainable policy approach to greenhouse and are already pricing greenhouse risks into their future investment plans.

ERIG also notes the current relatively uncoordinated proliferation of state-based renewable and greenhouse schemes. Market participants have noted that these schemes raise regulatory risks, impose additional costs and red tape on energy investors and lead to uncoordinated and inefficient outcomes and reduced liquidity in financial markets.

However, ERIG notes that greenhouse matters require detailed analysis and such analysis has been beyond both the scope of ERIG’s review and its timeframe. ERIG notes, however, that greenhouse gas emissions and climate change are global problems. Unilateral action by Australia is unlikely to contribute significantly to global greenhouse gas abatement per se, even if it has some ‘signalling value’ encouraging others to act as well, because of ‘carbon leakage’ effects. Whatever the mechanism chosen, ERIG is of the view that effective solutions to achieving a reduction in greenhouse gas production will require an efficient price signal.

Benefits of Reform

ERIG’s economic analysis indicates that the potential benefits in the electricity sector from further reform as recommended in this report result in improvements to GDP of around $400 million per year over the medium term. Associated with this, retail prices of electricity can be expected to fall over the medium term by around 2% or so.

This analysis is constrained by the inherent limitations of general equilibrium and other modelling approaches, and limitations on the data that is used in such modelling approaches. However, benefits in the form of dynamic efficiency gains cannot be well quantified but over time these may be the most important gains of all. Accordingly, ERIG regards the estimates presented above as conservative.
ERIG’s Recommendations

<table>
<thead>
<tr>
<th>1</th>
<th>Improving Market Contestability and Efficiency</th>
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<tbody>
<tr>
<td>1.1</td>
<td>Privatisation of all energy supply assets</td>
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<tr>
<td></td>
<td>ERIG recommends disaggregation and full privatisation of government-owned energy assets throughout Australia, as soon as is feasible given the practicalities of the privatisation process.</td>
</tr>
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<td></td>
<td>This recommendation potentially applies to NSW, Queensland, Western Australia, Tasmania, the Northern Territory, the Australian Capital Territory, and to the government owners of Snowy Hydro Limited. Given the dominance of NSW (33%), Queensland (28%) and Victoria (26%) in terms of generation output shares within the NEM, the efficiency benefits from this recommendation depend most heavily upon implementation within NSW and Queensland (Victoria having already privatised its energy supply assets).</td>
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<td></td>
<td>ERIG acknowledges that the small size of the ACT and Northern Territory markets may militate against significant gains from disaggregation in the Territories, although privatisation plus appropriate regulation may still be desirable over time. ERIG regards this as a ‘first best’ recommendation. In part at least, it is not consistent with current government policy in NSW, Queensland, Western Australia, Tasmania, the Australian Capital Territory, the Northern Territory and for Snowy Hydro Limited.</td>
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<tr>
<td>1.2</td>
<td>Privatisation of some energy supply assets</td>
</tr>
<tr>
<td></td>
<td>Where recommendation 1.1 is not considered feasible at present, ERIG recommends disaggregation and privatisation of some electricity assets, such as those in the contestable market segments (generation and retail), as soon as is feasible given the practicalities of the privatisation process.</td>
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<tr>
<td></td>
<td>ERIG welcomes the decision by the Queensland Government to privatise its retail electricity assets, and notes public statements by the Tasmanian Government about the possibility of a similar initiative.</td>
</tr>
<tr>
<td></td>
<td>This recommendation potentially applies to NSW, Queensland, Tasmania, Western Australia, the Northern Territory, the Australian Capital Territory and to the government owners of Snowy Hydro Limited. That said, ERIG acknowledges that the small size of the ACT and Northern Territory markets may militate against significant gains from disaggregation in the Territories, although privatisation plus appropriate regulation may still be desirable over time.</td>
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1.3 Encouraging private investment in energy

Where recommendation 1.1 is not considered feasible at present, but where Governments, for budgetary reasons, do not wish to allocate additional public resources to investment in electricity assets, ERIG recommends that the clearest possible signals be given to the private sector that it will be permitted to invest on a ‘level playing field’ to meet forecast demand.

ERIG considers that Western Australia has given relatively clear signals to date. Enshrining these in legislation, beyond Ministerial Directions, and allowing incumbent government businesses to sell down assets to allow them to compete, may make signals even clearer. Other States, notably New South Wales, could improve the clarity of signals currently presented to the private sector. ERIG notes that, even when effective, this ‘hybrid’ model, where both public and private sector ownership exist in competition, increases tensions between government- and privately owned businesses. This intensifies the need for effective governance arrangements and genuine competitive neutrality (see below).

This recommendation potentially applies to NSW, Queensland, Tasmania, Western Australia, the Northern Territory, and the Australian Capital Territory. ERIG acknowledges that the small size of the ACT and Northern Territory markets may militate against significant gains from new investment by the private sector in those markets because of the ‘lumpiness’ of investment, at least until there have been significant increases in demand. Contestability for the ACT market entails supply from elsewhere in the NEM, anyway.

1.4 Disaggregation of government electricity assets

Where recommendation 1.1 is not considered feasible at present, ERIG recommends disaggregation of government-owned electricity assets.

That said, ERIG is sceptical about whether disaggregation, and continuing government ownership, will provide significant benefits. For it to do so, further reforms enhancing competitive neutrality and improving governance arrangements will be crucial (see below).

This recommendation potentially applies to NSW, Queensland, Western Australia, Tasmania, the Northern Territory, and the Australian Capital Territory. It may be of particular value in NSW, if competitive neutrality arrangements can be improved (see below). ERIG acknowledges that the small size of the ACT and Northern Territory markets may militate against gains from disaggregation in the Territories.
1.5 Strengthening competitive neutrality safeguards

Where recommendation 1.1 is not considered feasible at present, ERIG recommends strengthening of safeguards for competitive neutrality between government- and privately-owned energy businesses. See also recommendation 3.1 below.

These cannot fully deliver competitive neutrality, but they can improve on the status quo. Specific competitive neutrality recommendations under recommendation 1.5 are set out below. These recommendations potentially apply to NSW, Queensland, Tasmania, Western Australia, the Northern Territory, the Australian Capital Territory and Snowy Hydro Limited.

1.5.1 All debt to be arranged through commercial mechanisms, eliminating explicit benefits (and minimising implicit benefits) from perceptions of government guarantees.

1.5.2 State-owned Electricity Corporations to be subject to the Corporations Act 2001.

1.5.3 Electricity Corporations to pay all government taxes and charges, including company tax, with state governments to receive no company tax advantages from company income generated by such businesses.

1.5.4 Board appointments to be independently determined, based on appropriate skills for appointment.

1.5.5 Dividend payout policy to be determined by the Board based on commercial requirements for the business in question, rather than by government decision.

1.5.6 Corporations to report to governments on their business activities in compliance with ASX listing rules.

1.5.7 Independent decision making on operational and strategic management directions by government owned enterprises.

1.6 Retail price caps as barriers to competition

The MCE has agreed retail price caps should be removed after competition exists in electricity markets. ERIG concludes there is an inherent contradiction between (i) waiting for competition to emerge before removing price caps, and (ii) the fact that binding price caps themselves constitute impediments to competition.

ERIG recommends that this contradiction be reviewed and resolved, either by COAG and/or by the MCE. The Victorian practice of fostering competition and easing price caps simultaneously may be a useful guide to solving this problem Australia-wide.

ERIG also recommends that governments conduct a detailed review of CSO arrangements, directed to delivery via non-distorting, transparent and targeted mechanisms in place of such ‘blunt instruments’ as retail price caps.

These recommendations apply to COAG and most States and Territories.
## Improving Market Governance

### 2.1 Ministerial Council on Energy

To support its own 2003 agreement to strengthen the national character of energy market governance, and to sharpen its own broad policy-making function, ERIG recommends that the MCE’s role should be reviewed by COAG. The focus of the review should be (i) to ensure the MCE concentrates solely on broad policy-making for the energy market; (ii) to eliminate more detailed intervention by the MCE and its officials in detailed rule-making; and (iii) to evaluate the merits of an increased policy oversight by the Commonwealth Government or COAG to support a more ‘national character of governance of the energy markets’. (See also recommendation 5.3)

This recommendation applies to COAG.

### 2.2 Planning

ERIG recommends that planning functions be strengthened beyond those embodied in the SOO/ANTS processes, in order to enhance system-wide energy investment efficiency (covering both generation and energy transmission/distribution) on a truly national market basis. (See also recommendation 4.3)

This general recommendation applies to COAG. More detailed recommendations on planning are presented in chapter 6 below.

### 2.3 AEMC

Of all the governance recommendations made by ERIG, those relating to the AEMC are amongst the most urgent.

ERIG recommends that the AEMC’s funding, autonomy, accountability and board structure be improved as a matter of urgency. More specifically, in the interests of a national market approach, ERIG recommends that: (i) the AEMC’s funding be made transparent and adequate for its role, and, preferably, be the responsibility of the Commonwealth Government; (ii) the AEMC have more control over its own work programme, subject only to being fully accountable to governments for its performance in delivering against government policy objectives for Australia’s energy markets (eg, efficiency and reliability); and (iii) AEMC’s resources should allow it independently to appoint a full-time Board, comprising members with appropriate experience and, consistent with good governance, free from perceptions of (actual or perceived) conflicts of interest.

These recommendations apply to COAG.
2.4 Electricity market rules and other matters

ERIG recommends that operating rules and other state-specific legislation and regulatory instruments should be harmonised across Australia’s energy markets to support a more national market framework. As part of this process, the current numerous state derogations from existing rules, and differences in retail regulation and other state regulations, should be greatly reduced.

ERIG also recommends that there be an independent review of the implementation of energy market reform and, as part of this, progress towards national consistency, as part of any NRA outcomes monitoring arrangements.

These recommendations apply to COAG and all States and Territories.

2.5 NEMMCO

ERIG recommends that NEMMCO’s governance be reformed for it to operate more autonomously. See also recommendations 4.5 and 5.4 below.

In particular, ERIG recommends that industry representatives be involved in the appointment of NEMMCO’s Board. The NEMMCO Board appointment process should seek to ensure that the board is independent of individual jurisdictional or sectional interests and contains the appropriate range of skills.

The reform of NEMMCO’s governance would contribute to NEM-wide efficiency and is justified in its own right. This recommendation also has important implications for other recommendations presented in chapters 6 and 7 below, as well as a possible national energy market operator function (see recommendations 2.7 and 5.11). These recommendations apply to COAG, and all NEM States and the ACT.

2.6 The Western Australian IMO

While it is too soon to assess the performance of the Western Australian Electricity Market (the WEM), ERIG is concerned about the multiplicity of functions allocated to the IMO. These seem to involve significant potential governance problems (mainly functional conflicts of interest).

ERIG recommends a review by the Western Australian Government of these governance issues in order to identify whether actual problems exist, and to deal with them if they do.

In this context ERIG recommends that Western Australia investigate the merits, at least over time, of using the AER, the AEMC and NEMMCO as the regulator, rule-maker and operator, respectively, of the WEM. (See also recommendations 2.3, 2.7, 4.7 and 5.6)

This recommendation applies to Western Australia.
2.7 **A national energy market operator**

From a national efficiency perspective, there is much to be said for moving as quickly as possible to a national energy market operator in place of the current electricity market operators (several), and gas market operators (several).

Subject to acceptance of recommendations concerning NEMMCO’s governance presented in this chapter and in chapters 6 and 7, ERIG recommends COAG agree to establish a single energy market operator as a longer term governance improvement for the Australian energy market, rather than having separate gas and electricity market operators.

ERIG recommends COAG develop a detailed program timetabling the steps to the establishment of a single energy market operator. (See also recommendation 5.11)

This recommendation applies to COAG.

2.8 **AER and ACCC**

For Australia’s energy markets, the regulatory function seems to be relatively well settled (subject to resolution of the issues raised under the ‘regulatory adequacy’ recommendations set out below). From a national market/efficiency perspective, the main issue is the sub-national coverage of the AER.

ERIG recommends that the AER should have responsibility for energy market regulation across Australia. (See also recommendation 2.6)

This recommendation applies to Western Australia and the Northern Territory.

3 **Improving regulatory adequacy**

3.1 **Proscription of generator/transmission mergers**

ERIG agrees with the 10 February 2006 COAG decision to proscribe generator/transmission mergers. ERIG recommends that this policy—still being developed by the MCE—should be announced as soon as possible to remove avoidable investment uncertainty. ERIG also recommends that this policy should apply equally to government- and privately-owned businesses.

These recommendations apply to COAG and all States and Territories.

3.2 **Removing ambiguities in the coverage of the TPA**

ERIG recommends that any ambiguities or uncertainties about the application of the TPA to government-owned businesses—eg, due to ‘crown immunity’ considerations—should be removed as soon as possible through appropriate state legislation.

This recommendation applies to COAG and all States and Territories.
3.3 Applying the Corporations Law consistently

Substantial ‘carve-outs’ from full application of the Corporations Law to government businesses currently apply in three states and one Territory. These confer a potential competitive advantage on government businesses relative to private competitors, undermine good governance, and weaken even-handed application of competition regulation. ERIG recommends that these ‘carve-outs’ should be abolished through appropriate state/territory legislation (see also recommendation 1.5.2 above).

This recommendation applies to NSW, Queensland, Western Australia, and the Northern Territory.

4 Achieving a fully national efficient transmission grid

ERIG considers that to develop an efficient, national transmission grid the following inter-related elements are required:

- improved locational signals to generators;
- stronger incentive framework for TNSP’s to better support outcomes in the electricity market; and
- an appropriate national mechanism for coordinating and integrating the national development of the power system.

These are the critical elements of a total reform package which can be expected, over time, to lead to significant benefits for Australia. The proposed regime would not aim to remove all transmission constraints but would seek to drive the most efficient mix of well located generators and transmission investment to meet Australia’s future electricity needs. It would also seek to deliver at all times the most effective use of the existing transmission infrastructure and support trading in the competitive market. Specific recommendations follow in each area as do a number of related supporting recommendations.
4.1 Locational Signals to Generators

The AEMC is currently conducting a review of congestion management in the NEM “to consider the requirement for and scope of enhanced trading arrangements in relation to constraint management and pricing”. The scope of that review needs to be widened to ensure the review addresses the need for efficiency of operations and dispatch in the short term and to drive efficient investment in the longer term.

An efficient regime in a competitive market context must, either explicitly or implicitly, price the cost of material congestion in the grid. In doing so, it will enhance the incentives to generators to invest in favourable locations relative to the grid. The need for appropriate locational signals for generators is a pressing matter given the scope of new generation investment required to meet Australia’s growing needs.

ERIG recommends that the AEMC congestion review should deliver a management regime which will both improve the efficiency of operations and dispatch in the short term and meet the allocative efficiency imperatives in the longer term.

ERIG recommends that the MCE review the terms of reference for the AEMC’s congestion management review to ensure consistency with the broader recommendations of ERIG and economic efficiency principles to ensure they have the scope to recommend such arrangements.

ERIG recommends that the MCE implement the recommended regime (and the appropriate transition measures) if it meets the criteria set out in the amended terms of reference by end 2008. The MCE should report to COAG on the review of the terms of reference and the outcomes of AEMC’s review within 6 months of the completion of the review.

4.2 Improved incentives on TNSPs

The ACCC and now the AER have been developing performance measures and an incentive regime to apply to TNSPs for a number of years. The work has led to the publication during 2006 of valuable market impact measures but has fallen short of any improvements to the incentives applying. ERIG supports the implementation of an initial incentive scheme as set out in the revised Rules (para 6A.7.4). Within that timeframe, the AER will not be able to develop as comprehensive a scheme as necessary to drive efficient outcomes and the new congestion management scheme and national planning arrangements will not be in place.

ERIG recommends that the MCE require the AER to commit to a timetable for the development and implementation of a comprehensive incentive regime for TNSPs by end 2007.
Improved national planning arrangements

ERIG believes that Australia must develop a more national approach in relation to energy network planning and investment, particularly in regard to transmission planning and investment. While our energy system needs to be enhanced to ensure a national approach is adopted where this enhances efficiency, its design needs to integrate ‘local’ requirements for reliability.

ERIG recommends that a new national planning function be implemented to undertake transmission planning, to inform the market and the regulatory processes and to coordinate the efficient development of the national transmission network. (See also recommendation 4.6)

ERIG further recommends that the new national planning function be developed consistent with decision making, performance and investment accountability remaining with individual TNSPs in a manner which complements and informs the Regulatory Regime.

The MCE should commission a review by the AEMC to detail the planning framework recommended by ERIG and to rewrite relevant sections of the law and the Rules including:

- detail the role and functions of the National Planner;
- implement rules requiring the National Planner to develop a National Transmission Network Development Plan (NTNDP) on an annual basis in accordance with network development objectives;
- develop Rules setting out the network development objectives under which the NTDP is developed based on integrating the two limbs of the current Regulatory Test;
- establish responsibilities for market participants and network service providers to provide information to the National Planner;
- put in place a formal mechanism for the involvement of industry participants and other stakeholders in the development of the NTNDP;
- link the role of the National Planner and the NTNDP to the regulatory regime and, in particular, to provide for these to inform the process for setting the ex-ante revenue cap;
- consider the development of any links between the congestion management regime and the national planner;
- introduce requirements for network service providers to undertake a Project Assessment and Consultation process on all major augmentations prior to final commitment. This process should ensure transparency around the decision to implement a particular solution including the assessment of non-network alternatives and demonstrate how the project is consistent with longer term development directions in the NTNDP; and
consider the value of other Rule changes consequent to the introduction of the national planning process and the formation of the National Planner such as changes to any Planner of Last Resort role.

There would need to be consequential changes to the law and the Rules to integrate the new planning arrangements with existing requirements and to replace current provisions where appropriate. The National Planner would replace the role of the IRPC, the NTDP should replace the ANTS and the new provisions would replace the current Regulatory Test arrangements.

4.4 National consistency of reliability standards

Chapter 3 of this report highlights the need for a consistent national approach to the national energy market. Where possible, the current plethora of different state government arrangements should be progressively examined and abolished in favour of consistent national measures. This is a particular issue in the efficient development of the national transmission network where different reliability standards exist in each state. The differences exist in terms of form, function and interpretation.

ERIG recommends that the Reliability Panel, which is formed under the AEMC, coordinate a national review to rewrite schedule 5.1 in the NER to provide a consistent national framework for Reliability Standards by end 2008. As part of this process, each state should review its requirements for individual connection points and publish them in that format.

4.5 Formation of the National Planner under a reformed NEMMCO

The Market Structures chapter of this report recommends changes to NEMMCO’s governance. The proposed changes along with the inherent synergies make the reformed NEMMCO the appropriate body to undertake the new national planning function. The placement of this much expanded function in NEMMCO would require significant change in NEMMCO and would benefit from a set of specific objectives to guide its Board and management.

ERIG considers that the development of a ‘National Transmission Network Development Plan’ is not possible without understanding and analysing potential developments in the competitive sectors, the nature and location of likely generation investments and the location and growth of customer load. The planning requires a range of inputs and oversight from a range of industry participants and stakeholders is seen as essential to the plan’s quality.

ERIG recommends that the National Planner be formed under the umbrella of a reformed NEMMCO and that NEMMCO be provided with a clear set of objectives for the carriage of this function. ERIG also recommends provision be made for the formal involvement of industry representatives and stakeholders in the development of the National Transmission Network Development Plan. (See also recommendations 2.5 and 4.3)
4.6 Future review of national planning arrangements

The arrangements for the introduction of the new national planning regime depend upon the development and implementation of effective commercial incentives on generators and TNSPs. The success of the regime needs to be reviewed within five years. This review should consider whether the incentive regime on TNSPs together with the coordination and advisory function of the National Planner have produced efficient outcomes or whether the role of the National Planner should be extended to provide it accountability for decision making and procurement of transmission services.

ERIG recommends that COAG review the arrangements for the introduction of the new national planning regime including the success of the regime. This review is to be completed within five years. (See also recommendation 4.3)

4.7 Recommendations for Western Australia

The arrangements described above relate specifically to the interconnected transmission grid covering Tasmania and the eastern states from South Australia to Queensland. Arrangements in Western Australia are different and have only been established for a relatively short period of time. However Western Australia operates a transmission network over a wide area and in a competitive market context. As such, the key principles for the efficient development of the Western Australian power system should be similar and ERIG has recommended exploring the potential to use national institutions for its development, operation and regulation. There are also potential advantages in applying the general principles recommended for the NEM in Western Australia in terms of:

» an appropriate congestion management regime in the short term forward market which is predictable and delivers productive efficiency,

» market based incentives for efficient service delivery by network service providers,

» the importance of power system and network planning information to inform the competitive market and network regulation.

ERIG recommends that COAG request the Western Australian government examine the potential benefits from introducing arrangements for the efficient development of the SWIS based on the general principles recommended for the NEM.
5 | Energy Financial Markets
--- | ---
5.1 | Capital markets and investment
ERIG recommends that COAG note that many existing participants in the market and a range of potential investors raised concerns with both the uncertainty about government policy on greenhouse gas emissions and the lack of a carbon pricing signal. The disparate range of State and Commonwealth greenhouse schemes also impose costs on participants and cause inefficiencies in the choice of fuels, plant and location and timing of investment and increased risk premiums. Development of greenhouse policy is outside ERIG’s terms of reference, however the issue has been unavoidable in our work and consultation and is brought to COAG’s attention for its consideration because of its adverse effects on market efficiency (noting also the comments under greenhouse gas abatement policy in chapter 5).

5.2 | Contract trading in the NEM
ERIG recommends that the MCE sponsor a strategic study on the potential for simplifying key aspects of trading across the NEM (without compromising the basic NEM design). Such work would include additional mechanisms to support interstate trade and the simplification of trading into SA and Tasmania.

5.3 | MCE Governance
ERIG recommends that the MCE develop a greater strategic and implementation capability, initially to address the issues identified in this Report. (See also recommendations 2.1 and 2.3)

This might include:

* empowering the AEMC to take a more proactive role in the development of market rules, but perhaps take a lesser role in more strategic market reviews;
* establishing a new strategic group (reporting to MCE) to manage the development of strategic policy; and
* increasing the use of expert groups where specific expertise, knowledge or industry involvement is required.

5.4 | NEMMCO Governance
ERIG recommends that industry should have a greater role in the oversight of a reformed NEMMCO’s market operations function through the formation of a Market Operations Panel, to oversee the specification and procurement of market operations functions. The MCE should commission work to detail and implement reforms to NEMMCO in consultation with stakeholders. (See also recommendation 2.5 and 4.5)
### 5.5 Institutional arrangements and market design

ERIG recommends that the ‘energy only’ design of the NEM be retained.

### 5.6 Improvements to the WEM

The material progress represented by the WEM is acknowledged and supported.

ERIG recommends that COAG negotiate with the WA Government with a view to the AEMC taking responsibility for the market rules of the WEM before the end of 2008; and

COAG request the WA Government to instruct the IMO to improve the workings of the capacity mechanism by strengthening significantly the capacity signal in the WEM and making it more market orientated. ERIG sees no reason why this could not be achieved within 12 months. (See also recommendations 2.6 and 4.7)

### 5.7 Inter and intra regional trade

ERIG recommends that the AEMC clarify the roles of Network Service Providers (NSPs) and NEMMCO in contracting generation to support transmission capacity and flows.

ERIG recommends that the AER with the AEMC, develop the framework for encouraging NSPs to enter into network support contracts where generators or demand side contribute to avoiding or deferring transmission investment. These should be simple and standardised arrangements for DSM or generation embedded in the distribution system.

ERIG recommends that NEMMCO develop market support contracts where generators or demand side are able to support flows on transmission assets which improve energy market outcomes and where the costs exceed the benefits.

ERIG recommends that the inefficiencies created by the operation of the Snowy Region be resolved as a matter of urgency. AEMC should be provided with a broad brief by MCE to resolve this matter by December 2007, including an interim solution if the Snowy Region is abolished, to cover the 3 years notice before a regional change can be implemented.

ERIG recommends, to ensure the settlement residue instrument delivers the most efficient outcome, the MCE commission an independent feasibility study designed to improve the management of settlement residues as detailed herein.
5.8 Settlement of spot and contract markets and credit

Under the current NEM design, spot and contract markets are largely settled separately. This results in duplication of credit requirements in the spot and contract markets. This situation increases systemic risk, creates timing differences and increases barriers to entry and is increasingly important with the privatisation of retail in Queensland.

While ERIG would expect a restructured NEMMCO would deal with all operations related to the market, it is recommended in the interim that:

» the MCE commission an expert group with industry representation to develop a plan for the integration of spot and forward markets in the NEM. This investigation should explicitly examine the feasibility of establishing a voluntary national settlements and clearing facility and a strategy for implementation should the benefits outweigh the costs. This group should report back to the MCE by December 2007 with options and solutions.

» AEMC and NEMMCO develop a plan for integrating SFE contracts into the NEMMCO settlement process, to be implemented by September 2007, subject to the risks being managed appropriately.

5.9 Demand response

ERIG recommends that the MCE develop a strategy for automation of DSM suitable for application to small customers; and review the institutional arrangements to ensure that participants can capture the benefits of DSM and drive the DSM development process.

5.10 Government and regulatory issues

There are a number of areas where Governments and ASIC could consider action to better support and remove barriers to the development of more efficient financial markets, thereby fostering reduced risk premiums.

ERIG recommends that the NSW Government remove ETEF in accordance with the timetable it has communicated to the market.

ERIG recommends that the Queensland Government phase out or abolish the LEP.

ERIG recommends that ASIC clarify to industry participants their obligations under the FSR Act.

ERIG recommends that CAMAC, in consultation with the industry and large DSM customers, review its requirements under the FSR Act for wholesale participants in the energy markets, keeping requirements to those relevant and necessary.

ERIG recommends that CAMAC, in consultation with the gas industry, considers the FSR Act obligations to ensure they do not impede the efficient development of financial markets in gas.
5.11 Gas Financial Markets

The GMLG recommendations offer worthwhile progress and are generally supported.

ERIG recommends that the MCE provide the necessary support for the timely implementation of the GMLG recommendations including supporting the establishment of a National Gas Market Operator (GMO).

ERIG recommends that the MCE ultimately oversee the merger of the GMO with NEMMCO after NEMMCO’s governance has been modified as proposed elsewhere. Resolution of this matter should not be allowed to impede the development of a national gas market operator. (See also recommendations 2.5, 2.7 and 4.5)

Greater standardisation of market structures, market processes, pipeline access and supply points for pricing across the market is required. Further work is required to assess the upstream areas of acreage management and joint marketing.

ERIG recommends that the GMLG, or a successor group, develop an implementation plan for the standardisation of market structures, rules, conventions and systems in the gas market.
1 ERIG’s task

ERIG Terms of Reference

At its meeting on 10 February 2006, COAG agreed that further reform of Australia’s energy sector would yield significant efficiency and energy security benefits.

COAG convened the Energy Reform Implementation Group (ERIG). ERIG was asked to report before the end of 2006 on reform recommendations for:

- achieving a fully national transmission grid including the most suitable governance and transitional arrangements having regard for COAG’s objective of achieving a truly national approach to the future development of the electricity grid, the legitimate commercial interests of asset owners, and the need to promote investment that supports the efficient provision of transmission services;
- any measures that may be necessary to address structural issues affecting the ongoing competitiveness and efficiency of the electricity sector; and
- any measures that may be necessary to ensure there are transparent and effective financial markets to support energy markets.

ERIG panel members

ERIG was chaired by Mr Bill Scales AO. In addition to his role on ERIG, Mr Scales is also the Chancellor of Swinburne University and the Chairman of the Port of Melbourne Corporation and the Australian Safety and Compensation Council. Mr Scales was supported by:

- Mr David Swift, Chief Executive of the Electricity Supply Industry Planning Council of South Australia, who led the Transmission Work Stream;
- Mr Geoff Carmody, co-founder of Access Economics, who led the Market Structures Work Stream; and
- Mr Alan Rattray, former chair of the Southern Hydro Board, who led the Financial Markets Work Stream.

Senior officers from AEMC, NEMMCO and AER acted as ex-officio observers on the ERIG Panel.

ERIG was supported by a small Commonwealth-State government secretariat.
ERIG process

For each of the three work streams: transmission; market structures; and financial markets; reference groups consisting of key industry and other stakeholders were established to provide advisory support to ERIG. An officials’ reference group (ORG), representing all jurisdictions, was also established to provide advice on key energy policy issues. The membership of ERIG’s reference groups is detailed at Appendix 3.

ERIG released an Issues Paper for public consultation on 5 July. 50 submissions were received on the Issues Paper. Three Discussion Papers were released on 17 November 2006. The Issues Paper and Discussion Papers are available at www.erig.gov.au. 42 submissions were received in response to the Discussion Papers. A public stakeholder forum was held in Sydney on 7 December to consider comments on the discussion papers.

The importance of energy

The electricity supply industry is a key component of national output, contributing 1.4 per cent to Australia’s GDP. The sector directly employed around 39,000 people at the end of June 2005 (ABS 2006b) with the gas supply industry employing a further 2,100 people.

Access to competitively priced and reliable energy is fundamental to the productivity of nearly all economic pursuits and contributes significantly to the wellbeing of all Australians. It’s an essential service.

For example, the NEM supplies electricity to more than 8 million Australian customers on an interconnected national grid that runs through Queensland, New South Wales, the Australian Capital Territory, Victoria and South Australia.

Reforms to date

Since the early 1990s, the electricity sector has seen continuing reform that has delivered significant benefits to consumers and the economy.

The objective of these reforms was to ensure the production and delivery of electricity to minimise costs to consumers. Market mechanisms and regulatory reforms were adopted to improve the efficiency of electricity supply.

National Competition Policy was a key element supporting energy market reform. The Competition Principles Agreement (CPA) required corporatisation and separation of government-owned businesses into natural monopoly networks and competing service providers. It also subjected government-owned assets to the TPA. This was intended to allow private firms to compete in many previously government dominated sectors, such as energy.

In the 1990’s the NEM began in the eastern states.
The Parer Review

The COAG-commissioned Parer Report, *Towards a Truly National and Efficient Energy Market*, was completed in December 2002. It identified priority areas for energy market reform including:

- strengthening the quality, timeliness and national character of governance of energy markets;
- streamlining and improving the quality of economic regulation across energy markets;
- improving the planning and development of electricity transmission networks;
- increasing competition in generation to allow Australia’s gross pool system to work as intended;
- enhancing the effectiveness of financial markets, including establishing firm interstate trading rights;
- removing impediments to the demand side playing its true role in the market;
- increasing competition in natural gas and addressing uncertainty around new pipeline development; and
- implementing an economy wide emissions trading system to address poorly targeted greenhouse measures in the energy sector.

An examination of the progress made by governments in implementing the Parer recommendations is detailed in Appendix 7.

MCE energy market reforms

The MCE, with representatives from each state/territory, established two new bodies – the AEMC and the AER.

- The MCE is also putting in place a number of other important reform initiatives, particularly the creation of new national legislation for gas and electricity and reforms in areas such as transmission, retail pricing, consumer advocacy, merits review and facilitation of DSM.

Implementation of these reforms by the MCE is expected to be completed by 2008. The MCE’s energy market reform program and an assessment of progress against Parer’s recommendations are provided at Appendix 7.

Results of reform to date

The Australian economy has experienced 14 years of sustained uninterrupted economic growth, one of the longest expansion phases on record. Other key indicators of economic strength are also evident, such as high per capita incomes and low unemployment rates (Productivity Commission, 2005).
Strong Australian productivity growth has been the driver. During the five year period to 1998-99, productivity growth rates were the highest rates for at least forty years. Productivity Commission (PC) modelling estimated that benefits of competition reforms in the infrastructure sector increased Australia’s GDP by 2.5 per cent per year. This increased average household income by $7000 per year (Productivity Commission, 2005).

Energy market reforms over the past two decades have played a significant role in these gains. For example, analysis conducted by Short et al (2001) indicated that energy market reforms by the year 2000 had resulted in a $1.5 billion (in 2001 prices) increase in GDP.

While international comparisons are difficult, Australia appears to have some of the lowest electricity prices in the developed world. Industrial electricity prices are 38 per cent below the IEA average and household prices are 31 per cent below the average across the IEA countries (IEA, 2005).

Overseas analysts believe Australia has one of the most competitive and efficient electricity markets in the world. The IEA considers the Australian electricity market to be a model that other countries could follow.

“Ireland was one of the pioneers in energy sector microeconomic reform and should be commended for its vision and implementation of a liberalised (electricity) market. Australia now has one of the most transparent and competitive electricity markets in the world and could serve as a model for other countries” (IEA 2005).

That said, there is a widespread belief that more can be done. If this was not the case, ERIG would not have been established. ERIG’s job is to establish whether or not this belief is justified.
2 An efficiency focus

Energy, including electricity, is a very important part of the Australian economy. The economic efficiency with which it is produced, distributed and consumed is crucial. Regardless of who owns and operates energy production, generation, transmission, distribution and retail businesses, ERIG has been asked to make recommendations that will help them to perform more efficiently.

This report examines the scope for boosting economic efficiency by:

› identifying impediments to ‘best practice’ energy production & distribution;
› identifying impediments to efficient consumption of energy;
› within ERIG’s Terms of Reference, recommending specific, practical measures governments can take to remove these impediments.

What does ‘efficiency’ mean in practice?

‘Efficiency’ — as an economic concept — covers several dimensions:

› existing energy assets should operate at ‘best practice’ levels (technical efficiency);
› investments in energy assets should generate competitive returns (capital efficiency);
› the allocation of resources to the energy sector should be ‘just right’ — that is, not too much and not too little — given competing demands for those scarce resources (allocative efficiency);
› over time, the relevant signals and incentives should allow all of these efficiency dimensions to be sustained — the ‘right’ amounts of investment at the ‘right’ times; and
› these efficiency dimensions should be seen from a national perspective (see chapter 3 below).

These dimensions of efficiency are best achieved when competition occurs, driving market outcomes towards output priced at the lowest sustainable cost. Competition—or competition-equivalent outcomes—therefore is a key practical test for establishing whether efficiency can be improved or not.

The need for system-wide economic efficiency

Energy production and use are very inter-connected. For example, in the electricity system:

› generation, transmission, distribution and consumption occur at the same time;
› increasing transmission capacity may reduce the need for increased generation capacity, and increase the competitiveness of the national generator market;
increasing generation capacity may reduce the need for increased transmission capacity and reduce effective ‘bottlenecks’ within the transmission system (as well as saving on energy losses in transmission); and

improving financial market performance may reduce the cost of managing risk, the pressure for generator-retailer integration, and ease barriers to entry into the retail segment of the system.

This means energy markets must deal simultaneously with:

- generation and retail market segments, where there can be enough participants or contestability to promote competitive outcomes under the right conditions;
- transmission and distribution networks, where a single, or very few, asset operators is a sensible allocation of resources, but where a ‘natural monopoly’ market is the result;
- the reality that improving efficiency in one market segment has effects on the efficiency of other market segments; and
- making sure, in the light of all this, that the allocation of resources across all market segments—simultaneously—is ‘just right’.

So system-wide efficiency, in the light of this inter-connectedness, is complex.

Scope of ERIG’s analysis

Comprehensive market analysis should cover both demand and supply. These jointly determine price and quantity outcomes.

ERIG has been asked to investigate three specific issues covering:

- electricity market structures (ie, including within the contestable markets);
- the transmission segment (ie, a regulated market segment); and
- the financial markets associated with energy markets.

Within ERIG’s Terms of Reference, there are some specific issues with potential demand-side implications, but COAG has specifically referred other demand-side issues to the MCE. ERIG has commented on demand-side issues where it considers that these are likely to deliver efficiency gains if addressed.

Only two policy choices: efficiency or inefficiency

Australian governments face limited choices when deciding policy for energy markets (or indeed other markets). Available resources are scarce and using them one way usually prevents their use in other ways.

In the case of energy markets, these boil down to (i) choices about how energy markets will balance (ie, how demand will be made equal to supply), and (ii) choices about how much of Australia’s scarce resources will be allocated to supply in these markets.
For choices under (i), governments must decide between:

- allowing prices to balance demand and supply and allocate resources; or
- allowing quantity restrictions to do the same job – via ‘blackouts’ or ‘brown-outs’; or
- paying for excess capacity, even when it is not used, to prevent supply interruptions.

For choices under (ii), governments must decide between:

- trying to ensure resources allocated to energy supply and use are ‘just right’; or
- allocating either insufficient or excessive resources to energy production and use.

Only if governments choose the first option in both cases will economic efficiency be achieved. If other options are chosen, inefficiency will be the result. This can take various forms:

- energy prices will be higher than they need be;
- ‘blackouts’ and ‘brown-outs’ will be a feature of Australian energy markets;
- excessive resources will be tied up in the energy industry.

If inefficient options are chosen, Australia’s living standards will be lower than they could otherwise be:

- if too many resources are allocated to energy markets, a great deal of capital is tied up which could be used for other things. Where governments are making these investment choices, there are direct costs for the community because fewer government resources are available for hospitals, schools, roads, and the like; or
- if too few resources are allocated to the energy markets then brownouts, blackouts and general unreliability of supply ensue. This has a high economic cost.

Resources are scarce. That’s why economic efficiency in energy markets is crucial.

A comment on reliability

Energy (including electricity) reliability is crucial. ERIG accepts that very high reliability standards are an essential part of energy supply specifications. The cost of involuntary and unpredictable energy supply reductions or interruptions is high. Australia is an energy-intensive economy.

In the NEM, the Reliability Panel, established by the AEMC in accordance with the NEL and the Rules, is tasked with monitoring and advising on the safety, security and reliability of the national electricity system and in determining appropriate reliability standards.

In its May 2006 Issues Paper, released as part of a comprehensive reliability review, the Reliability Panel, noted that the current NEM reliability settings comprise:

- an explicit reliability standard for generation and bulk transmission (currently set at 0.002 per cent unserved energy, over the longer term);
» price mechanisms designed to ensure that the wholesale spot market meets that standard including a price cap known as the Value of Lost Load (VoLL) with a market floor price and a cap on financial market exposure (the cumulative price threshold); and

» an intervention mechanism known as the reliability safety net, should the price mechanism fail.

In addition to this framework, networks are built to different standards in each NEM jurisdiction.

It is not for ERIG to specify the level of such standards. This is essentially a cost-benefit exercise. However, ERIG considers these standards should be set on as national a basis as possible.

Gas

Gas is an important substitute for electricity and a key input into the production of electricity. To some extent, ERIG has considered implications of its analysis for the Australian gas market, particularly in the Financial Markets chapter. However, the time available to ERIG to complete this review has not permitted a full examination of specific issues pertaining to the gas sector.

That said, the option of having a truly national energy market operator, rather than separate electricity and gas market operators, has been flagged as an important economic efficiency matter in this report.
3 A coordinated national approach

For Australia to compete in an interdependent world, it will need to continue improving its national productivity. This is the basis for sustainable improvements in living standards.

Market size imperatives

By international standards, Australia’s market is small, amounting to about 1 per cent of global GDP in purchasing power parity terms.

On the supply side, for many production processes, economies of scale are substantial. These must be harnessed as much as possible for Australian production to be internationally competitive. For most of Australia’s energy production, these crucial features are also relevant.

This means that fragmentation of Australia’s markets into different sub-markets; for example, based on state jurisdictions or even smaller regions, can be (and is) particularly damaging to Australia’s ability to compete internationally. It can (and does) also hamper the ability of Australians to trade efficiently across state boundaries within Australia.

On both counts, this market fragmentation is a direct threat to higher Australian living standards because it undermines the ability of business in the energy sector to operate as efficiently as possible.

For at least two decades Australia has been moving towards a more coordinated national approach to policies, practices and institutional arrangements that have proven to be the major determinants of a healthy and vibrant economy.

Australia has a national approach to trade policy, the operation of its financial markets, its approach to consumer law and business law and regulation, competition policy, and, increasingly, the operation of its labour market.

At present, Australia has a mixed approach to energy policy. The AER and AEMC have been established as national energy market institutions but there remain gaps in the scope of their functions and geographic coverage and progress to establish national energy market legislation has been too slow.

Further, even after the current package of energy market reforms are implemented, there will remain a large number of areas where different state-based approaches to energy policy, regulation, planning and governance will reduce efficiency and at the very least result in additional red tape and higher costs for our energy industry. Whilst, this approach has served Australia reasonably well in the past, ERIG believes it is not best practice and considers that it will not be capable of serving Australia well in the future. Further evolution is necessary to achieve more coordinated national outcomes.
In ERIG’s view, establishing a national approach to energy policy, regulation, and practice will necessitate having a national approach to the governance of Australia’s energy markets. However ERIG has made limited judgements about the model that Governments should adopt in this regard, including the mix between greater coordinated action or greater Commonwealth responsibility. Irrespective of the model or models adopted the result must be a much more integrated and coordinated market structure.

Energy’s role in improving Australia’s productivity

Sustaining Australia’s economic growth without re-igniting inflation (and, thereby, putting at risk both past economic gains and future growth), is a major economic policy challenge confronting Australian governments. The only way that sustained economic growth can continue to be achieved is by continuing to improve Australia’s national productivity.

Dealing with this challenge will require careful use of Australia’s scarce resources. This applies at least as much to our energy resources as to any others.

This is important because domestically located Australian businesses are not the only businesses wanting to use Australia’s energy resources. Many countries want access to Australia’s energy resources and this is already creating tensions in Australia about how these resources are to be allocated.

Australia is a continent with a large land mass but a relatively small population. Its population bases are both highly concentrated and highly geographically dispersed. About half of Australia’s population resides in just three cities: around 21 per cent in Sydney; 18 per cent in Melbourne; and around 9 per cent in Brisbane.

Energy generation, transmission and distribution systems have to deal with these realities, often entailing long distances between energy sources and users.

ERIG believes that all elements of the energy production, distribution and retail system will be dominated by organisations that, for effectiveness and efficiency reasons, will want to be able to operate in Australia as one national market. They will expect energy policy, regulation and governance arrangements to be arranged to accommodate that reality. Economies of scale and scope available to national energy companies can be expected to deliver greater efficiency and lower costs.

Most energy market participants want Australia to adopt a more national approach to energy market issues. These include Australia’s approach to:

» transmission planning and investment;
» regulation across the National Energy Market;
» governance of its energy market institutions;
» deregulation of retail energy markets and the lifting of price caps; and
» for current and potential investors in the energy sector, a national approach to greenhouse emissions policy.
The investments these companies need to make to meet Australia’s future energy needs are both large and long term. A level of certainty is therefore necessary, from their perspective, to allow them to invest in this sector.

ERIG strongly believes that securing Australia’s energy future will necessitate the development of a consistent, coherent and national approach to all elements of energy policy, regulation, governance and practice.

Creating a national energy market

ERIG’s report is not the first to highlight the need for a national energy market. The Parer Report provided a number of key recommendations which, if implemented, were expected to take Australia the next important steps along the road towards achieving a national energy market.

In its report ‘Reform of Energy Markets’ to COAG on 11 December 2003, prepared in response to the Parer Report, the MCE agreed that further reform should be undertaken to “strengthen the quality, timeliness and national character of governance of the energy markets, to improve the climate for investment” (MCE 2003, page 4).

The MCE recognised that governments should not be engaged in the day-to-day operations of energy markets, and should concentrate on a broad policy making role (MCE 2003, page 7).

COAG agreed that a governance framework for the national energy market should be established with:

» the MCE providing national oversight and coordination of energy policy development and national leadership on energy issues;
» the AEMC responsible for rule-making and energy market development at a national level;
» the AER responsible for economic regulation and compliance at a national level; and
» NEMMCO responsible for the day to day operation and administration of the power system and electricity wholesale spot market in the NEM.

In addition, Australian governments agreed to implement a national legislative framework for gas and electricity.

National governance: an essential efficiency ingredient

National energy markets should be guided, at the highest level, by broad policy objectives covering efficiency and reliability that are coordinated or set nationally. For these objectives to be national in character, the highest level of Government in Australia should be involved in setting such objectives.

It is the Commonwealth Government, working through COAG, which has the appropriately national perspective and incentives in relation to such matters. Further, the institutions
operating and managing energy markets need to be at the very least nationally coordinated in their Charters, Board structures, funding, accountability, and transparency.

ERIG believes substantial reform is needed to achieve this for Australia’s energy market. For example:

- separate market operators apply to the NEM, where NEMMCO operates; the WEM, where the IMO operates; and the Northern Territory market; as well as to gas markets (currently covered by VENCorp, Gas Market Company (GMC) and Retail Energy Market Company (REMCo)). ERIG wonders why shouldn’t there be a single national energy market operator for Australia?

- the AEMC has been established as the national rule and market development body, but there are serious questions about its funding, ability to act strategically and to manage its workflow, and limits to its national reach;

- as the NEM market operator, could NEMMCO do more to advance the interests of the NEM as a whole relative to jurisdictions within the NEM? Could NEMMCO become the electricity market operator for Australia as a whole?

- Australia is moving towards a single regulator, the AER, although full implementation of that policy has not yet been achieved; and

- numerous state derogations from the national rules and regulations covering energy exist, creating a different legal and regulatory framework for the energy market in each state. These differences are compounded by different state regulatory arrangements, different licensing regimes, guidelines, codes of practice and other regulatory requirements.

These matters are examined in more detail in chapters 5-7.

These problems have been recognised at the highest level of government. At its 10 February 2006 meeting, COAG agreed to “work collectively to strengthen the national energy market” including “to remove barriers to full retail competition” and to establish “a truly national approach to the future development of the national electricity transmission grid”.

These commitments are welcome. Different arrangements in each state increase costs, ultimately to customers. They increase barriers to entry and undermine the reality of a national market. The overall impact of these differences is greater than the individual parts because of the adverse investor perceptions that this complex and confused policy and regulatory burden creates.

Separate state legislation also applies in a number of other areas including greenhouse gas reduction schemes. Even more state-based schemes have been announced recently.

ERIG has concluded that Australia currently does not have a fully national energy market. For example, as noted in more detail in chapters 6 and 7 below:

- transmission planning and decision-making remains regionalised since the start of the NEM. Whilst collaboration has occurred on individual interconnector projects, comprehensive strategic national planning with the objective of determining an optimal system-wide investment program has not developed;
» state government control and/or ownership of TNSPs appears to have diluted a national focus. The ownership by governments of generation assets and transmission has potentially created additional conflicts of interest;

» network pricing arrangements do not recognise and charge interstate beneficiaries of proposed augmentations;

» different laws, regulations and licence conditions cover the provision of transmission services and operation of transmission companies in each state. These impose different obligations and network planning standards across the electricity system, often allowing a large amount of discretion in the application of reliability obligations to various points on the network;

» each state also has its own requirements in relation to retail competition, and licensing of retailers; and

» trading in financial markets between regions is more difficult and risky than it needs to be.

Further, where governments remain as major supply-side participants in the industry, ERIG believes that the impartiality of objectives and mechanisms to achieve a national energy market, such as decisions of the MCE to establish nationally consistent rules and regulations, are likely to be significantly compromised. ERIG believes (see chapter 5) that the privatisation of state energy assets will go a long way to address this issue. Government ownership together with the various protective programs and policies in some states inhibits private sector investment and restricts the emergence of efficient, nationally focussed companies.

ERIG strongly believes that single Australia-wide, energy market-wide, independent (and preferably separate) institutions covering:

» planning;

» market operation;

» market regulation; and

» rule-making

are urgently required and would be the logical evolution of current market governance arrangements.

A national market, good governance, and economic efficiency, are all crucial—and mutually supporting—ingredients in the recipe for optimising use of Australia’s scarce energy resources and thus supporting Australian living standards at the highest sustainable levels.
4 Market performance

Overview

On the basis of analysis provided by consultants, and other public research, there is some evidence suggesting national productivity gains as a result of past electricity reforms have been substantial. However, these gains vary between jurisdictions in the NEM.

Productivity estimates provided by consultants raise questions about the general economic efficiency of parts of the NEM.

Based on observed outcomes, there are market signals suggesting the need for new capacity in New South Wales. One private participant has committed to building new capacity.

A summary of recent NEM performance is presented in table 1 below.

1 National Electricity Market performance summary

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<th>Price trends – average annual change$^1$</th>
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<th>Retail prices$^3,4$</th>
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</table>

1 In 2005-06 terms. 2. For the period 1999-00 to 2005-06. 3. For the period 1993-94 to 2005-06 in 2005-06 dollars. 4. In capital cities only. 5. For the period 2002 to 2005. 6. A negative transmission utilisation growth rate indicates increasing asset utilisation. 7. Victoria and South Australian capital productivity combined under Victoria.

Performance focus

The focus of this chapter is the economic performance of the NEM for the period 1999-2000 to 2005-06. The economic performance of any market is assessed by considering both the productive efficiency of firms operating in the market, and the allocative efficiency of the market overall.

Productive efficiency is concerned with identifying how close to their technical ‘best practice’ firms are operating in any market. This ensures that the sustainable cost of producing the goods is as low as possible. This is sometimes undertaken by benchmarking firms and identifying the best production opportunities available. However, due to difficulties in identifying both the appropriate technology with which to make the assessment, and the difficulty in collecting sufficient data, productivity analysis is often undertaken on a comparative basis, drawing on observations about performance in different regions or markets, or performance over time.

Allocative efficiency is concerned with ensuring that resources are allocated in a manner that maximizes the net benefit available through their use. In contrast to technical efficiency, where the focus is on ensuring costs are minimized, allocative efficiency is concerned with ensuring market prices reflect those efficient costs, and thus consumer benefits are maximized. Prices deviating from levels reflecting those efficient costs are a sign that the benefits to consumers are not as large as they might be.

The focus is on the NEM because this is where market reforms have been in place the longest. Significant reforms occurred in NEM regions prior to 1999-2000, especially in Victoria, where reforms were implemented earlier than in other regions and gains in productivity were stronger, albeit from relatively poor levels. The analysis below does not reflect all benefits achieved across the NEM during this earlier period.

Tasmania only joined the NEM in 2005, and there has been insufficient time to judge how participants in that jurisdiction have responded to market signals.

Western Australia has implemented reforms to its connected south-western market. Energy trading in the WEM commenced in September 2006 and capacity trading in the WEM has been in place for over two years. It is too early to assess the performance of the WEM or the operations of WEM participants.

Like WA markets, the Northern Territory electricity market is not connected to the NEM. It consists of three relatively small, regulated systems, with the largest, the Darwin/Katherine system, having a total capacity of 339 MW connected on a 132kV network. The other two are both less than 100 MW. In such a set of small systems, effective competition in generation may be difficult (if not impossible) to achieve. ERIG is advised that options for reform of the Territory’s electricity regulatory framework are currently being developed by the Northern Territory Treasury. ERIG does not believe it is appropriate to comment on that process at this stage.

The assessment of the performance in this chapter draws both on work commissioned by ERIG and on appropriate publicly available economic assessments of the performance of the market. Nonetheless, ERIG has been cautious in accepting any single piece of evidence on its own. Rather, ERIG has adopted a ‘weight of evidence’ approach, relying on evidence only where reasonably consistent findings can be inferred from disparate sources of data.
ERIG notes the market has been in existence for a relatively short period of time, especially when considering the economic life of installed assets (often stretching well beyond 30 years or more). The full adjustment of market participants to the conditions applying within the NEM may take many years to become fully apparent.

Given this relatively short timeframe over which either productivity or allocative efficiency assessments can be made, together with the difficulty in obtaining sufficient data, means that a number of additional, simplifying, assumptions may have been required in order to focus on the key issues.

ERIG believes it is unlikely that any single piece of evidence presented in this chapter can be relied on alone to draw definite conclusions concerning any aspect of market performance. However, in assessing the evidence in total, where findings in specific markets are repeatedly identified across different methodological approaches, ERIG believes it is valid to accept such findings.

Price outcomes in the NEM

Wholesale spot market outcomes in the NEM are shown in figure 1 below.

Real spot prices in all NEM regions except NSW have trended down since 1999-2000 following investment in additional capacity—either in the form of new generating plant or through upgrades to existing plant—combined with increases in the transmission network, including inter-connectors. These increases in capacity increased competition within the NEM, but also coincided with relatively cool summers. With warmer summers and record peak demands occurring over the last two years, prices have risen on average, relative to earlier this decade.

In contrast, real spot prices in NSW have remained relatively stable since market start with, if anything, a small upward trend over time.

1 Spot market price level outcomes in the NEM (1999-00 to 2005-06)
Information on retail price levels to residential consumers by jurisdiction is limited, or not available, especially in jurisdictions where full retail competition has been introduced. However, based on CPI-based retail price indices for state and territory capital cities published by the Australian Bureau of Statistics (see figure 2), a number of points can be noted.

In the period since the early 1990s when reform began, real retail electricity price indexes have generally been falling – particularly in Melbourne, where real retail prices have fallen at an average rate of 1 per cent a year. In Adelaide average retail prices jumped 24 per cent in 2002-03, associated with the removal of historical and regulated tariffs at a time when significant new investment in generation was required. Real prices have since fallen as retail competition in that region has increased. Retail prices include payments for network investments, which have been substantial in some jurisdictions in recent years, as well as the wholesale and retailing cost of energy.

Productivity measures

ERIG commissioned McLennan Magasanik Associates (MMA) to examine the productivity performance of the generation and transmission sectors of the industry. MMA examined a number of partial productivity measures in these sectors, such as labour productivity and capital productivity. A number of physical measures of capital productivity were also included such as capacity factors, availability and transmission to load factors.

2 Retail electricity price indexes by capital city (1980-81 to 2004-05)\textsuperscript{a}

\begin{figure}
\centering
\includegraphics[width=\textwidth]{electricity_price_indexes.png}
\caption{Retail electricity price indexes by capital city (1980-81 to 2004-05)\textsuperscript{a}}
\end{figure}

\textsuperscript{a}. In real 2005-06 values, 1996-97 = 100, using CPI as the deflator.

Source: ABS 2006a
Important caveats apply to the productivity conclusions reached. Long lives of investments in electricity supply assets raise analytical challenges when deciding how to consider investment decisions made prior to the period of analysis. Any deviation in investment away from the efficient level, either in the network or generation sectors, can have long-lasting effects on system productivity. Decisions made prior to, or during preparation for, the reforms introduced over the last ten years may have on-going consequences not related to the management and operation of transmission and generation companies during the period.

The lack of suitable publicly available data to normalise productivity measures across different NEM regions means differences in levels across regions due to geographic considerations, particularly in the transmission sector, cannot be eliminated.

In general, therefore, it is not possible to make comparisons about productivity levels across regions. However, all measures of productivity used have been applied consistently across NEM regions. This allows comparison of trends in the key variables across regions. When considered across a range of partial productivity measures, this analysis raises important questions about why performance trends vary across NEM regions.

When considering benchmarking transmission performance and drawing on international evidence when assessing Australian performance, the Australian Competition and Consumer Commission (ACCC) noted that, although different grids may face different geographic environments with different temperature profiles and potentially different cost structures, “these differences are much less significant when considering changes in efficiency over time” (ACCC 2005).

Due to limited data availability and time constraints, MMA restricted its analysis to the period 1999-00 to 2004-05 for transmission, and to 1999-00 to 2003-04 for generation. This covers trends since NEM market start, allows for generally consistent approaches to be used, and minimises concerns about productivity prior to market commencement, and concerns about disaggregating data for any merged entities that have arisen since reforms began.

Publicly available data on employment at the sector level is limited. MMA made a number of simplifying assumptions and used data from the ESAA and the Australian Bureau of Statistics (ABS).

Transmission productivity measures

Identifying the outputs of a transmission network and how to measure the quantity and value of each of them is difficult. MMA has identified a measure of transmission capacity as the most appropriate measure of output. Specifically, transmission capacity needs to cover expected peak electricity demand that has a 1 in 10 probability of being exceeded (POE) in any year.

The 10 per cent POE is calculated using the peak load data from NEMMCO provided as part of the ‘Statement of Opportunities’ publication as a forecast quantity. This is still an imperfect measure. It does not take into account the geographical dispersion of load centres across the states.
This measure of output raises challenges, especially as there are limited approaches to normalising the measure across regions. Meeting peak demand within a relatively small geographic region requires less transmission investment than a region with the same peak demand, but which is geographically larger. For example, by 2004-05, the 10 percent POE measure in Queensland was within 10 per cent of the same measure for Victoria, but the value of installed transmission lines was nearly 50 per cent higher in Queensland due to the longer transmission distances there. The focus of the MMA analysis is on productivity changes across regions, rather than comparing productivity levels across regions in an attempt to overcome this issue.

The 10 per cent POE peak demand measure also has the advantage that it is a forecast estimate derived by NEMMCO, independent from the transmission service operator. As with any forecast it is almost certain to deviate from the actual outcome. However, it is derived in a consistent manner and any biases in the methodology in deriving the estimate are likely to be consistent across all jurisdictions.

Capital productivity

Consistent datasets following market start have been difficult to obtain. Information on the capital base for each of the networks is sourced from the relevant regulatory decision of the AER on the network revenue cap. However, as the AER is yet to consider the revenue cap for the South Australian and Tasmanian transmission networks, these states have been excluded for the purpose of this analysis in order to maintain consistency in comparing productivity measures.

Capital productivity is measured in peak MW per million dollars invested. A negative growth rate suggests that, with the level of under-utilised capital increasing, investment may be occurring ahead of actual system requirements. If this were found to be the case, it may be due to a number of factors that are unable to be identified from the raw data alone. For example, it may be the difficulty associated with consistently and correctly forecasting peak system requirements, noting the aforementioned cooler summers and warmer winters in early half of this decade. Alternatively, other objectives pursued by the TNSP such as increasing the level of relative reliability ahead of an economically efficient level could also account for such an outcome.

MMA estimates of capital productivity for Queensland, Victoria and New South Wales are presented in figure 3.

Reflecting relatively little requirement to expand the transmission network in Victoria (with an average annual growth rate of the capital base of 2 per cent) since market start, the growth in peak demand requirements results in better utilisation of the Victorian network, with capital productivity growing at more than 5 per cent per year.

In contrast, the productivity of the New South Wales transmission system appears to have been gradually declining. Over the period 1999-00 to 2005-06, the capital base of the New South Wales transmission network grew at an annual average rate of 8.5 per cent; nevertheless, the average annual growth rate in capital productivity was minus 3.1 per cent. This measure is strongly influenced by the revaluation associated with the AER upward reset of the asset base in 2004-05. After excluding that effect, capital productivity is still declining, albeit it at an average of minus 0.2 per cent per year (see figure 3).
Although subject to a relatively high level of uncertainty, this latter estimate does raise questions about the rate of transmission investment relative to actual system requirements in NSW.

Queensland, like Victoria, is experiencing statistically significant growth in capital productivity. Over the period when the capital base of Queensland transmission assets grew at nearly 4 per cent a year (in real terms), capital productivity increased at an annual growth rate of 1.7 per cent. The strong growth in the Queensland asset base, combined with increasing productivity levels, would appear to reflect, amongst other things, responses to the strong growth in energy demand in that state.

**Labour productivity**

Data on the labour force is sourced from industry-wide state level data from the ABS, and disaggregated by sector based on information from the ESAA. Using the ABS data rather than employee data derived from annual reports provides a better basis for including resources that are contracted to the sector rather than directly employed.

Using the output measure defined above, labour productivity is measured as peak MW capacity per employee.

---

1. NSW growth rate adjusted to account for significant influence of AER reset (in 2004-05) on relatively short time period for assessing productivity.

Source: MMA

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**3 Capital productivity in the transmission sector (1999-00 to 2004-05)**

![Graph showing capital productivity of Victoria, New South Wales, and Queensland from 1999-00 to 2005-06.](image-url)
Labour productivity in the transmission sector (1999-001 to 2003-04)

Queensland has the highest average estimated annual rate of growth in labour productivity, at 3.2 per cent.

Using the data derived from the ABS and ESAA, New South Wales productivity growth appears to be declining over time. However, as a number of assumptions were required to derive the data, this needs to be taken into account when interpreting the labour productivity measures. Transgrid provided MMA with employee numbers over the period of analysis. Using that data, labour productivity in New South Wales is trending upwards over time —although, this estimate lies within a wide error margin—unlike the estimate derived from the ABS data.

MMA are also of the view that because the Transgrid data does not include personnel who are contracted to provide services to the sector in NSW there does not appear to be enough data to assemble a series that would be more accurate than the rough data series constructed in this report.

Victoria’s average rate of growth over the period was 1.0 per cent. The variability in productivity means that this estimate sits within a wide error margin. A number of factors should be considered. Victoria embarked on reform of the electricity industry earlier than other jurisdictions, including privatisation across all sectors. Private ownership may have brought a different discipline to managing network assets from that under government ownership. A number of studies, (albeit at the industry-wide level), have noted the very strong productivity growth achieved in Victoria relative to other states during the 1990s (Quiggin 1997, Short, Swan, Graham, Mackay-Smith 2001, Whiteman 1999).
Asset utilisation

MMA has calculated a Transmission to Load Factor ratio (TTLF) for each transmission network. This ratio is a summary measure of the geographical size of a system, denoted by a capacity measurement (associated with the size of the network), relative to its peak demand. It may be used for comparing the transmission line intensity of a transmission system between jurisdictions. In absolute terms, a reduced level of TTLF, in the absence of network development, would indicate increased asset utilisation.

Estimates of TTLF are shown in figure 5.

This measure appears to support the evidence provided earlier. Although both Queensland and Victoria exhibit an average annual rate of growth that is negative, the measure sits within a wide error margin, suggesting that there has only been limited improvement in these regions in asset utilisation during this period.

However, for New South Wales, the significant average annual growth rate of 2.8 per cent suggests that the level of installed transmission lines may be moving ahead of measures of peak demand requirements. MMA has noted that this appears to support the observation made earlier regarding capital productivity, relating possibly to investment in upgrades to the transmission network that may be too early when judged from a broad efficiency perspective.

5 Transmission to load factors (1999-00 to 2004-05)
Generation productivity measures

Unlike transmission, generation has a readily identifiable output: energy sent out. The same concerns regarding the assumptions required to construct both the labour force and capital datasets make precise labour productivity comparisons across NEM regions difficult to construct. However, as with the transmission analysis, the analytical approach used allows an evaluation of differences in both capital and labour productivity trends between jurisdictions.

Measures of labour productivity have been developed for New South Wales, Victoria, South Australia and Queensland. For capital productivity, South Australia and Victoria have been combined because of the number of privately owned generation companies with assets in both states (necessitating the need for a single measure of capital productivity for these states). The privately owned generators in Queensland were excluded from the analysis due to the difficulties MMA reported in obtaining the capital costs for these generators.

Labour productivity

Trends in labour productivity are shown in figure 6.

Trends across the jurisdictions are dissimilar.

Queensland experienced the highest and most consistent rate of growth in labour productivity, at around 5.3 per cent a year on average.

South Australia also exhibited a positive average annual growth rate – around 3 per cent a year. However, there was significant volatility over the period, and the estimated trend growth rate sits within a wide error margin. MMA has advised that it is difficult to interpret the trend change in productivity in South Australia due to a number of factors. The generation assets were privatized during this period, but the sale of the asset classes was staged. The volatility may reflect the outage of Playford Power Station during the refurbishment project and the series of mild summers and winters between 2002 and 2004, or may be a function of deriving the underlying data from broad aggregates.

6 Labour productivity in the generation sector (1999-00 to 2003-04)
Labour productivity in both Victoria and New South Wales recorded negative average annual growth rates over the period: minus 2.1 and minus 3 per cent, respectively. The volatility of labour productivity in Victoria and New South Wales across time and the small sample period results in imprecise estimates of the trend however.

**Capital productivity**

Trends in capital productivity are shown in figure 7 below.

As generation has a defined output flow, unlike the earlier transmission analysis, it is valid to consider productivity levels across regions, in addition to trends. Capital productivity in New South Wales appears to be significantly higher than in Victoria/South Australia or in Queensland. Part, but not all, of this difference arises because the valuation of the Victorian and South Australian coal fired assets included in the analysis also includes a life-time fuel supply, whereas the Queensland and New South Wales coal fired power stations do not own fuel supply assets.

The measured capital productivity in New South Wales was highly influenced by the revaluation of the generation assets in 2002-03. The NSW generation assets had previously been devalued in the mid 1990s. As a result of the subsequent revaluation earlier this decade, NSW experienced significant volatility in the growth of capital productivity in the analysis by MMA, but this nominal change in the level of productivity is unlikely to reflect changes in underlying capital productivity. After excluding the impact of the revaluation from the capital productivity estimates, the estimated annual growth rate in capital productivity in NSW is 3 per cent per year.

Capital productivity for the Queensland government owned generators has been relatively steady over the period of analysis, but is trending down at an annual average rate of almost 1 per cent per year. As with estimates for NSW, the estimate of the annual growth rate sits within a wide error margin. The estimated strong growth of productivity in Victoria/South Australia is considered to be statistically significant – even after excluding the significant downward revaluation of Loy Yang B in 2004.

7 **Capital productivity in the generation sector** (1999-00 to 2003-04)

1. Victorian and South Australian growth rate adjusted to account for the significance of the downward revaluation of Loy Yang B in 2004.

Source: MMA
Asset utilisation

Because of the limited availability of data on capital values, MMA considered alternative measures of capital productivity. These measures included capacity factors (the proportion of total possible output that occurred each year) and availability (the amount of time the generator plant is available to generate).

Because the load is not even across NEM regions, not all plant can operate at high capacity factors, and so differences in levels across regions should be anticipated. The analysis was confined to all plants within each region, but classed into public and privately owned assets.

The trends generally indicate that capacity utilisation has tended to remain fairly static, with little change overall in capacity factors across regions. The exceptions to this were publicly owned generators in Queensland and privately owned generators in South Australia (see figure 8).

In Queensland, capacity utilisation of publicly owned assets was estimated to increase at an average rate of 2.9 per cent per year, with a high level of confidence in the estimate. Further, by the end of the period, the capacity factor across publicly owned generators in Queensland was the highest in all the NEM. MMA has noted that this increase could be due to a number of factors, including high load growth in that state and the decommissioning of surplus capacity (Swanbank A). Most of the growth has occurred since 2001, when the Queensland grid was connected to the south east Australian grid, and some of the increase in generation capacity in Queensland resulted in exports of electricity to other NEM regions.

In contrast, the private generators in South Australia exhibited an average decline in capacity utilisation of about 1.5 per cent per year. MMA has suggested that this decline is probably due to the high level of new capacity that entered the market during the period of analysis and the increase in import capacity as a result of the commissioning of the Murraylink interconnector with Victoria.

Demand in South Australia is also more highly weather-dependent than other regions, with variations in summer temperatures resulting in big swings in generation levels from year to year. Some plants like Pelican Point and Torrens Island A also have large swings in generation levels from year to year.

8 Capacity factor trends (2000 to 2006)
When assessing availability (defined by the number of trading intervals when plants did not generate at all), the analysis was confined to high load duty plants with capacity factors greater than 55 per cent. Low duty plants, which, by their nature, are destined to have significant periods of not being required, and may therefore significantly influence the results, were excluded from the analysis by MMA.

The trends in availability for high load duty plant are shown in figure 9.

MMA states that statistical analysis of the availability between private and public generators indicates that there is no significant difference in the availability between private and public generators – a result that was consistent across all years of the analysis.

9 Availability factor trends by generator plant1 (1999 to 2004)

Investment signals

Are the prices presented in figure 1 at the start of this sub-section of the paper high relative to the costs of new entry into NEM markets, possibly signalling a need for new investment? Or are they too low, reflecting either sufficient or excess supply of a given type of technology? This cannot be determined from average prices alone. In an energy only market, substantial returns to the capital that is invested in installed capacity are earned when prices spike. (Note also that, in such markets, the efficient supply curve is defined by short run marginal costs. Efficient price spikes contribute to covering the difference between short and long run marginal costs.)
Expected prices are what matters as investment signals. Expected spot market outcomes are often bundled up within financial contracts that cover the majority of commercial transactions. But it is the magnitude of the price spikes, the duration of those spikes during a year, and the effects of these on price expectations, that matter both for investment signals and the setting of prices in bilateral contracts.

Care must be taken when examining spot prices, especially where contracts play a large role in overall commercial outcomes. Although the spot price reflects the marginal value to society at each point in time for the electricity consumed, it does not reflect the average price per megawatt-hour paid by buyers or received by sellers if those participants are also using financial contracts to manage their risk. As is the case in all markets, the prices of financial instruments used in electricity markets will reflect expected future spot prices at the time of entering into the financial contract, including risk premiums. In commodity markets generally, contract markets will trade at a premium to the physical spot market of the underlying commodity, reflecting the cost of managing risk (Wolak 1996). KPMG has advised ERIG that the premium in the contract market, relative to the spot market in the NEM, is around $4-5/MWh.

The spot price reflects the value to consumers of an additional unit of supply at each point in time. Spot prices provide a tool for economic analysis, which treats marginal costs and revenues as economic drivers. This includes assessing signals for new entry even where financial contracts are used to manage the risk for a substantial proportion of total consumption.

To assess the investment signals that arise from spot market price spikes requires that all spot prices be considered rather than just the yearly average. Spot prices over a year can be summarised by a price duration curve.

Price duration curves plot prices from highest to lowest over a year (or any given period), and depict the proportion of time (or hours) when prices exceed a given level. The price duration curve can also be interpreted as the probability that prices will be at or above a certain level. A stylised example of a price duration curve is presented in figure 10.

10 Illustrative annual price duration curve
In the example shown here, prices during the year exceed the short run marginal cost (SRMC) of a base load plant for almost 100 per cent of the year. In contrast, prices exceed the short run marginal costs of peaking plants for only a few per cent of the year.

A generator can only recover fixed costs, including the investment cost, when the price is above its variable (or SRMC) costs. The price duration curve conveniently summarizes all the individual price spikes that provide the necessary return on invested capital across all generation technologies. The area under the price duration curve and above the SRMC cost for a given technology gives the (expected) revenue that goes towards covering fixed costs for the year for that technology. This area is also known as the ‘aggregate price spike’ (Stoft 2002).

In figure 10, the area ‘a’ above the SRMC of the peaking plant represents the total returns to the peaking plant against all fixed costs, both capital and operating, for the period represented by the price duration curve. For base load generators, the combined area of ‘a+b+c’ provides payments against fixed and investment costs.

The average value of the aggregate price spike gives a measure of the contribution towards fixed costs on a megawatt-hour basis. This can be compared against estimates of the capital costs of new entry plant, expressed in energy equivalent terms, to assess market signals for new investment. If the average return from the aggregate price spike is expected to exceed entry cost for a new plant of a given technology, for a period sufficiently far into the future to fund investment in that type of technology, this is the market signal that investment in new capacity is required.

To examine recent spot market signals for investments in different technologies, the average aggregate price spike revenue from the spot market for base load and gas peaking plants for the past seven years in the NEM is presented in tables 2 and 3 respectively.

The figures in black (bold) represent values exceeding estimated new entrant costs. Figures in grey represent values below estimated new entrant costs.

### 2 Average aggregate price spike revenue: base-load a,b,c

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a For South Australia, the base load technology is taken to be a gas plant, whilst for the other jurisdictions, it is taken to be a coal plant. b. New entrant capital and fixed costs are sourced from ACIL-Tasman 2005. c. At an assumed 91 per cent capacity factor.

In a competitive market, average prices over the long term (defined as the period which equates with investment decisions for generation) will be at the level that just covers both fixed and variable costs of all technologies when the level of installed capacity is ‘just right’ to meet expected demand. In an energy only market, even when the level of installed capacity is ‘just right’, average prices exceeding new entrant costs will occur, as will prices
being below new entrant costs. This reflects the real world variations in demand associated with unexpected weather outcomes, or variations in supply due to overall plant availability being lower than normal due to coincident outages.

This phenomenon will be exacerbated when there is excess capacity in the market following restructuring. In this case, the number of years when prices are below new entrant costs are likely to be greater than those years in which prices exceed new entrant costs. This will continue to occur until demand growth over time absorbs the additional capacity, or some plant operations are scaled back or removed completely from the market.

For this reason, care must be taken in assessing the information in spot markets. Only if high prices are expected to be sustained are they a signal for new entry.

Although prices exceeded new entrant cost, for both base load and peaking capacity, frequently in the early days of the NEM, investments in those technologies in South Australia, Victoria and (more recently for base load plants) in Queensland, combined with Queensland becoming connected to the NEM, and upgrades to the interconnectors into South Australia, resulted in prices falling post-2001. That increase in capacity and availability of inter-state exports removed any spot market signals for new investment in most jurisdictions.

### 3 Average aggregate price spike revenue: peaking plants

<table>
<thead>
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<td>2000</td>
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<td>$576.40</td>
<td>$411.12</td>
<td>$1180.58</td>
</tr>
<tr>
<td>2001</td>
<td>$1116.06</td>
<td>$751.14</td>
<td>$349.96</td>
<td>$399.37</td>
</tr>
<tr>
<td>2002</td>
<td>$568.70</td>
<td>$538.48</td>
<td>$996.49</td>
<td>$1684.90</td>
</tr>
<tr>
<td>2003</td>
<td>$218.33</td>
<td>$248.18</td>
<td>$635.44</td>
<td>$435.38</td>
</tr>
<tr>
<td>2004</td>
<td>$825.36</td>
<td>$270.78</td>
<td>$1589.97</td>
<td>$768.84</td>
</tr>
<tr>
<td>2005</td>
<td>$413.95</td>
<td>$220.12</td>
<td>$1174.85</td>
<td>$449.93</td>
</tr>
</tbody>
</table>

* a. The aggregate price spike is considered for only 1 per cent of the year to assess signals for investment in peaking plant.
* b. New entrant capital and fixed costs are sourced from ACIL-Tasman 2005.

In contrast, spot market outcomes in New South Wales seem to have signalled that a new base load plant would have covered its annual investment costs in three out of the last four years. Further, it would seem that, on the face of it, from 2002 to 2005, investment in additional peaking capacity would also have earned a sufficient return on investment in both in NSW and in Queensland.

MMA has advised that some of the capacity within New South Wales, particularly at Liddell and Munmorrah, is maintained in a ‘semi-reserve’ status and is not fully available at least for some of the year. Further, the Snowy region, the largest peaking capacity available in Australia, is a neighbouring NEM region to New South Wales. It is difficult to reconcile the observed market outcomes indicating potential signals for both peaking and base-load capacity with the capacities available to support consumption in New South Wales. One possible explanation is that by being kept in reserve, this ‘reserve’ capacity may also act to support price levels for suppliers in that region—that is, effectively operate as practical barriers to entry to new entrants—despite relatively high price signals driven by customers through market demand.
ERIG notes that TRUenergy has committed to building a 400 MW gas fired power station at Tallawarra in NSW. ERIG also notes that, in addition to market signals, the NSW government has provided more certainty to TRUenergy by clarifying the arrangements that apply to greenhouse gas emissions, and by agreeing that publicly owned generators in NSW would not be investing in new generation capacity at the same time.

The above review represents a backward looking assessment of the investment signals in the market, looking only at prices with respect to investment grade plant. However, it is not an assessment of the efficiency of the market.

For long-term investments such as generation, it will be expected prices, inclusive of required risk margins, that will drive new investment.

### Market performance overall

A number of submissions, particularly from users, commented adversely on the impact of price spikes within the NEM. For example, the Major Energy Users submitted that these were both barriers to entry and a source of inefficiently high costs to users:

> “We have experienced extreme price volatility, which has increased risks to participants (and therefore costs to consumers) and which creates a negative and highly risky environment for new entrant generators, especially those not affiliated with incumbent retailers and generators” (Major Energy Users, 2006, p. 3).

These types of comments must be evaluated against a fundamental reality.

In energy-only markets price spikes are expected to occur. The key question is whether the observed volatility is considered efficient (that is, enough to provide the right investment signals), or excessive (that is, too high, and/or lasting too long, suggesting some form of market power or barriers to entry into the market on the supply side).

The benchmark for assessing the efficiency of all markets, including electricity markets, is whether or not observed prices are competitive. Competitive prices occur when the market price, representing the marginal value of an additional unit of consumption, is equated to the cost of producing an additional unit of supply. This is usually broadly represented through the intersection of the demand and supply curves, where the supply curve is derived from the aggregation of the short run marginal costs of the individual generators in the market. One measure of the efficient performance of the market is the observed closeness of this (price = short run marginal cost) relationship.

Price outcomes in the NEM will deviate from the competitive level whenever a generator has reduced its output from a given level (or conversely raises the minimum price at which it is willing to sell output) and increased its revenues by doing so (see Box 1 below). In this case, the generator is said to be exercising market power. In an energy only market, only when this behaviour is able to be repeated frequently do concerns arise about market power.

The alternative, leading to fully competitive outcomes, occurs when generators are prepared to offer to supply the market whilst ever prices equal or exceed their short run marginal costs of operation.
Box 1: What is market power?

Market power is defined as the ability of a producer to affect the market clearing price. Market power is exercised when generators through their own pricing and supply offers, can lead to market price outcomes for all producers, that are higher than the marginal cost of the last unit of supply – that is, electricity prices are higher than warranted by market-wide marginal costs.

The past two decades of international experience with wholesale electricity markets has demonstrated that significant consumer harm can result from electricity generators simply engaging in lawful unilateral profit maximising behaviour – because the electricity industry is more susceptible to the exercise of market power than any other industry (Wolak 2006).

Market power can be (i) sustained or (ii) transient (ie, lasting for limited periods of time). The absence of market power can be defined as a market where producers supply the market whenever prices equal or exceed their own marginal costs. In this case, market prices are equal to marginal costs of just enough supply to meet demand.

In energy-only electricity markets such as the NEM, price spikes are a normal feature, reflecting (a) volatile and price-inelastic demand and (b) a mix of generation plant in response to this volatility, ranging from low operating cost base-load plant up to high operating cost peaking plant.

On demand volatility, for example, over the last seven years, the within-year changes in consumption have varied from 215 per cent in New South Wales to over 330 per cent in South Australia. A feature exacerbating price volatility is unresponsiveness of demand to price changes in the short-run. Also, at any point in time, generation capacity is fixed, regardless of price.

Price spikes can be entirely consistent with a competitive market. They occur when demand shifts to peak levels, and most or all generation plant is called on to meet that demand. At such times, where marginal costs can increase quickly as demand approaches capacity limits, competitive prices can exceed the marginal cost of producing the required electrical energy from the last generator dispatched but can still be less than the marginal cost of an additional unit of energy from another generator. In this case, all generators receive market clearing prices higher than their own marginal costs, but still involve no exercise of market power.

Market power may be a sustained phenomenon, which points to market structure problems manifested in barriers to market entry. Alternatively, it may be a transient problem, occurring only when demand is at or above certain levels. However, even transient market power can impose significant economic harm even though it occurs for a short period of time (Willet 2005, Wolak 2006).

Both sustained and transient market power can be problems. The former points to removal of entry barriers as the solution. The latter may point to similar solutions, if it results in significant deviations from average efficient prices, even if it lasts for only a short proportion of time. The smaller the economic impact of transient market power, the less it is a problem. Dealing with short-period market power may point more to examining rules governing participant behaviour than to market entry problems.

But price spikes alone are not necessarily evidence of market power.
The economic result of generators exercising sustained market power is higher prices to consumers, lower than efficient output levels, a reduction in the economic efficiency of the spot market, less efficient operation and effectiveness of forward markets, and, over the longer term, potentially inefficient entry into the generation market (such as under- or over-investment in peaking capacity) and an inefficient mix of generation.

Several studies have demonstrated that for much of the time since the NEM commenced, there is publicly-available evidence that prices have deviated from the efficient competitive level due to supply withdrawal or re-pricing of output by generators (see for example, Bardak, 2005, Biggar 2005, Biggar 2003, Short and Swan 2002).

The 2005 study by Darryl Biggar, the most recent examination of the performance of the market, but whose findings are consistent with the other works cited above, noted several features in the market when examining the behaviour of large base-load portfolios in each NEM region for the period January 2003 to August 2005. Notably that:

- generators in the NEM are ‘withholding [output] frequently and withholding fairly large amounts on average’;
- withholding of output occurs generally when demand exceeds 60 per cent of peak demand in a region, with the exception of South Australia where withholding appears to begin at around 45-50 per cent of peak demand in New South Wales, the higher the level of demand, the higher the average withdrawal;
- in South Australia, the average amount withheld seems largely independent of the level of demand;
- in Victoria and Queensland, the average amount withheld seems to decline as the demand approaches peak demand; and
- the level of withholding varies across regions:
  - NSW generators seem most frequently to withdraw output, with the average amount withdrawn consistently around 300MW for each portfolio;
  - Victorian generators withdraw output half as frequently as NSW generators, with the average amount withheld around 220MW; and
  - both Queensland and South Australian generators withdraw much smaller amounts on average (around 100MW), with the exception of Tarong Energy (which averaged above 200MW).

The Biggar study concluded that:

‘generators in Australia’s National Electricity Market do have a degree of market power and they exercise that market power regularly. The impact on market prices seems to be most significant in New South Wales’.

ERIG notes that generators in the NEM bid in accordance with market rules. Similarly, individual generators acting unilaterally through decisions regarding either the level of output they offer to the market, or how they price that output offer is, appropriately, completely legal under the TPA.
The Biggar study also compared the estimated impact on market outcomes from withholding output in 2004 based on the assumption that the amount of capacity identified as being withdrawn in any given period was instead made available to the market (see table 4 below). Of the results, the most significant impact of supply withholding is that simulated prices in NSW were 50 per cent above the efficient level.

ERIG notes that yearly price outcomes in the NSW region were the highest in 2004 (in nominal terms), and that although the Biggar analysis of withholding covered the period of January 2003 to August 2005, the impact on price outcomes in 2003 and 2005 is likely to have been lower in those years relative to 2004. However, the evidence presented in the Biggar analysis is consistent with the evidence present in tables 2 & 3 above.

### 4 Impact of withholding on the 2004 market price

<table>
<thead>
<tr>
<th>Region</th>
<th>estimated efficient prices(^1,2,3) $/MWh</th>
<th>estimated market prices(^2,3) $/MWh</th>
<th>Percentage increase</th>
</tr>
</thead>
<tbody>
<tr>
<td>South Australia</td>
<td>47.10</td>
<td>53.84</td>
<td>14%</td>
</tr>
<tr>
<td>Victoria</td>
<td>24.65</td>
<td>28.18</td>
<td>14%</td>
</tr>
<tr>
<td>New South Wales</td>
<td>36.07</td>
<td>54.04</td>
<td>50%</td>
</tr>
<tr>
<td>Queensland</td>
<td>31.56</td>
<td>37.45</td>
<td>19%</td>
</tr>
</tbody>
</table>

\(^1\) The efficient price represents the expected price, given the level of installed capacity, rather than the price that would be expected to arise if historical capacity investment decisions had been optimal.  
\(^2\) Average prices for the period when market power was deemed to be exercised.  
\(^3\) These price outcomes reflect the ‘simplified NEM Dispatch Engine’ used in the Biggar analysis and are not actual market prices. Appropriate identification of potential impact requires dispatch outcomes be identically modeled.

Source: Biggar, 2005.

It is worth noting that the assessment of market outcomes against efficient prices (as represented by perfect competition) is a very rigorous benchmark and one which many markets might fail from time to time. Further, in estimating the efficient market price, the Biggar study necessarily made a number of simplifying assumptions, including the use of a simplified version of the NEM ‘dispatch engine’. Given the exacting criterion of fully efficient prices and the uncertainties in estimating the competitive market benchmark, there is a range of prices within which the market may be considered ‘workably competitive’.

In an interconnected NEM, the higher than normal price volatility occurring in New South Wales identified in the Biggar analysis may have spill over effects into other regions. That is, the increased risk of price spikes in New South Wales may lead to high risk premiums arising in financial markets in regions outside of New South Wales. As far as ERIG is aware, the potential impact of this has not been examined in publicly available studies.

### ACCC view of market power

The ACCC has expressed concern about both the extent of market power in the NEM, and the potential to exercise that market power, many times – from the original Authorisation of the National Electricity Code (ACCC 1997), through to recent comments by ACCC Commissioners (eg, Willett 2005).

In 2002, the Chairman of the ACCC stated:
“... structural...reforms are incomplete leaving large generation companies with significant market power in some circumstances” (Fels 2002).

In September 2001, the former National Electricity Code Administrator submitted applications for code changes to behavioural rules regarding rebidding for authorisation to the ACCC. In the following 15 months, substantial consultation and debate within the industry occurred over both the extent of market power and whether behavioural restrictions were an efficient manner to deal with any identified problems.

In the Authorisation, rejecting most of the proposed code changes, the ACCC outlined a number of issues. The ACCC stated that although:

“... the Commission agrees that there is certain behaviour that is unacceptable because it has a detrimental affect on the market’s operations and effectively games market outcomes” (ACCC 2002).

that

“... addressing market power through market design measures, such as rebidding, is a poor substitute for appropriate structural reforms” (Fels 2002).

Further:

“... structural reforms...are more likely to have a lasting beneficial effect on market behaviour than continued refinement of the rebidding rules, although the Commission concedes that in the absence of structural reform, reform of rules may be the only option available” (ACCC 2002).

The ACCC also noted that much of the debate around market power focuses on spot price outcomes in the NEM. As significant revenue flows to generators occur through the contract market, analysis of the contract market is necessary to understand bidding and rebidding behaviour in the NEM. Further, the ACCC notes that

“... it will be prudent to monitor the contract market, as well as the spot market, when assessing the prevalence of undue market power, and to consider factors which may affect the operation and competitiveness of both markets” (ACCC 2002).

The ACCC Authorisation included a preliminary analysis of market power in the NEM. The ACCC noted that in 2002, the

“... time-weighted [spot market] average is around new entrant levels for base load generation in Victoria and South Australia, commonly asserted to approximate $40/MWh, although it is somewhat higher in the other states”.

When considering the contract market, the ACCC noted that

“prices applying to contracts for 2004 onwards were around $35/MWh to $40/MWh for such contracts, which may be slightly below the new entrant level”. 
The ACCC went on to state:

“From this brief analysis, there is little to indicate conclusively that there is significant abuse of market power occurring at present. There is no evidence for example that contract prices are remaining above new entrant levels. … On the contrary, contract prices appear to be at or below new entrant levels and it appears that there is ongoing recruitment of new capacity in those areas where supply is scarcest. However, there is some evidence of the average spot market price exceeding new entrant prices, and this would be of concern if the condition persisted over a period long enough to allow new entrants to enter, for example two years or longer. … Of course, this brief analysis cannot be taken as conclusive, there is uncertainty regarding key data such as forward prices and volumes. In addition, the relevance of peaking generation to the debate has not been examined. It is included here primarily for illustrative purposes” (ACCC 2002).

Although noting that the ability of the spot market in electricity to ‘drive’ short term contract markets may not be as strong as in other commodity markets where commodities are storable (unlike electricity), the ACCC also noted that:

“…to the extent that the spot market drives the contract market, it may be appropriate to seek remedies to abuse of market power in the contract market through refinement of spot market design…for example, it appears that recent spot market volatility has influenced the price of short term forward contracts (but not longer term contracts)” (ACCC 2002).

In 2004, in a submission to the ‘Inquiry into National Competition Policy’ undertaken by the Productivity Commission, ERIG notes that the ACCC included an earlier version of the Biggar analysis (discussed above) that ‘explains how generators can exercise market power by withholding capacity at times of high demand’ (ACCC 2004). In its submission the ACCC stated:

“The ACCC remains concerned that…the potential for some generators to exercise market power is high at particular times…the ACCC has considered generation market power issues in detail. Generation market power manifests in very unique ways, and raises some important issues which should be considered in the context of how policy measures could promote more competitive market structures” (ACCC 2004).
ERIG findings on market performance

As noted earlier, the empirical evidence available to ERIG contains limitations. As such, it would be inappropriate to place undue weight on any single piece of evidence. Instead, ERIG has chosen to consider the weight of all evidence presented to it and draws on findings that appear to emerge consistently across all data considered.

Real spot market prices in all regions, except New South Wales, have declined over the period 1999-2000 to 2005-06. Further, although noting the relatively strong capital productivity performance of generators in New South Wales, overall, the productivity analysis suggests that across a range of other measures, productivity gains in other regions have been larger and have occurred faster than in New South Wales.

With regard to price outcomes in the spot market, care must be taken in assessing spot market information. However, ERIG finds it difficult to reconcile the observed market outcomes on price with outcomes on new investment in New South Wales. That is, the appearance of market price signals for both additional peaking and base load capacity appears to be at odds with the existing level of capacity available in NSW.

In assessing market performance overall, ERIG accepts that, in the NEM, there is some evidence of the on-going exercise of market power. This appears to be persistent, but intermittent. The magnitude of non-competitive outcomes appears to be such as to have a material adverse impact on the economic performance of the market. This appears to be most significant in New South Wales.

What should be done about this evidence of transient market power? This is a matter that depends on the nature of the problem. To the extent that the problem appears to be greatest in NSW, in the first instance, structural solutions such as disaggregation and privatisation may be appropriate. These matters are dealt with in chapter 5 below.
5 Market structures

Overview

Establishing and preserving contestable energy markets is the most appropriate way to develop and sustain Australia’s energy future. Freely contestable energy markets deliver sustained investment in energy assets and lowest-cost energy supplies.

Currently there are three threats to competitive and efficient markets within Australia’s energy sector: barriers to market entry, poor governance, and, to some extent, inadequate regulation against uncompetitive market outcomes.

There is evidence of barriers to more public sector investment in energy markets due to rising pressures on government budgets. Governments prefer to use their scarce resources in other areas.

There is also evidence of barriers to private investment in energy. These are due to government policy (e.g., uncertainty about greenhouse gas abatement policies, retail price regulation) and to government ownership of energy assets. In NSW, government ownership has come with relatively high spot prices and investment returns, but limited new investment. In Queensland, past early public investment appears to have made new private investment less viable. Government ownership raises concerns that there is not a ‘level playing field’. Government businesses have operating advantages over competing private businesses that cannot be completely removed while governments own energy assets which directly compete with private investments.

There is scope further to improve governance in the energy sector. A sharper separation between governments as broad policy makers, on the one hand, and the bodies responsible for planning, rule making, regulation and market operation, on the other, would help clarify the allocation of responsibilities, eliminate potential conflicts of interest, and reinforce independence and transparency. This is particularly important while governments continue to own public energy assets which compete with private investments.

Reforms concerning the funding, autonomy and board structure of the AEMC clearly are needed. More uniform standards, regulations, structures and rules across Australia would improve efficiency in the energy sector.

A more independent and focussed NEMMCO board structure would support other reforms (e.g., on planning, and regarding the possibility of a national energy market operator).

On the evidence, competition-protecting regulation is largely adequate. The exceptions relate to government-owned energy businesses. For these businesses, there seem to be uncertainties as to whether the Trade Practices Act applies in all situations, and there seem to be substantial ‘carve-outs’ from the Corporations Act. Both exceptions should be urgently reviewed and addressed.
Market structures terms of reference

As noted in chapter 1, ERIG’s market structures terms of reference require it to consider structural issues affecting the ongoing competitiveness and efficiency of the electricity sector.

In response to this remit, this chapter concentrates mainly on the contestable segments of the electricity market (i.e., generation and retail). By ‘contestable’, ERIG means markets where barriers to entry are (or can be) low or non-existent, and where sustained above-normal profits will (or should) induce new suppliers to enter the market in competition with incumbents.

ERIG notes that the effective threat of new entry or increased supply is often sufficient to impose a discipline on incumbent suppliers, restraining them from imposing excessive price increases on their customers.

A key feature of properly-working competitive markets is that barriers to entry are low or absent. In such conditions, producers cannot sustain excessive profits because these will signal new supply into the market, competing away such excesses.

Focus: economic efficiency via competition

This chapter concentrates on whether or not potentially contestable segments of Australia’s electricity markets are in fact contestable, and therefore competitive. In contestable markets, competition is the key driver for lowest-cost sustainable prices for energy.

A key role of governments is to ensure that, where possible, markets are contestable, and, therefore, as competitive and efficient as possible. Such markets deliver the largest supply of goods and services at the lowest sustainable cost, thereby underpinning the highest feasible standards of living for the community. As noted in the Hilmer report:

“Competition provides the spur for businesses to improve their performance, develop new products and respond to changing circumstances. Competition offers the promise of lower prices and improved choice for consumers and greater efficiency, higher economic growth and increased employment opportunities for the economy as a whole.” (Hilmer Report, 1993 page 1).

Scope: energy markets, not just electricity markets

ERIG’s market structures terms of reference explicitly refer to electricity markets. However, ERIG judges that reading this in context means that a wider energy market focus is appropriate.

ERIG has been asked to examine ‘structural issues affecting the ongoing competitiveness and efficiency of the electricity sector’. However, ERIG does not consider that this can be undertaken for electricity in isolation.
Market realities suggest a broader scope. In the market for electricity:

- gas is a supply-side competitor (investment in gas production and pipelines competes with investment in electricity generation and transmission);
- it is also a key input into electricity production itself (e.g. for ‘peak’ and ‘intermediate’ power generation); and
- gas is often a very close demand-side substitute in many end-use applications.

Policy realities support this broader view.

ERIG notes that its work is part of a wider reform agenda being pursued by COAG and the MCE that seeks the implementation of national energy market structures that foster competition. This agenda includes other electricity and gas market reforms with which any recommendations made by ERIG would be complementary.

In this context, a significant emphasis of energy market reform has been the NEM covering the interconnected eastern states electricity grid and the access arrangements for natural gas pipelines. Although ERIG’s terms of reference for the transmission work stream imply an emphasis on the NEM, its terms of reference as a whole are equally relevant to the Western Australian and the Northern Territory electricity and gas markets.

Ultimately, an energy market-wide perspective, and the potential efficiencies arising from rationalising institutions charged with planning, operating and regulating across energy markets as a whole, point to an energy market focus, rather than a narrower electricity market focus.

Impediments to competitive energy markets

Overview

In considering whether or not energy markets are competitive, ERIG has concentrated on two key questions:

Are competitive market outcomes being undermined?

If so, can government decisions address the causes?

Where impediments to competitive market outcomes can be fixed by government decisions, practical reform recommendations to governments can be made.

In evaluating Australian energy market competitiveness and efficiency, ERIG has sought evidence-based findings about ‘what’s broken’ that needs fixing.

In principle, markets may be uncompetitive and inefficient because:

- there are barriers effectively preventing new suppliers entering the market; and/or
- there are inadequacies in the ‘rules of the game’ set by governments to foster competitive market conditions.
Both groups of potential problems are important.

The first directly affects the contestability of the market. Getting contestability ‘right’ is an essential market structure objective. The second problem can also affect market contestability, as well as incumbent suppliers’ behaviour in the market. Adequate regulatory safeguards and even-handed market ‘rules of the game’ are needed to prevent significant lessening of competition.

ERIG is particularly interested in problems governments can fix by their own decisions. Identifying such problems can lead to specific, practical, recommendations to governments for further reforms.

As a result of its consultations, informed by submissions received, and arising from its own deliberations, ERIG sees the following as potential structural impediments to competitive and efficient energy markets in Australia:

A. Potential barriers to market entry

I. Government budgets as barriers to public entry
   » Are actual or looming budget constraints limiting public sector investment in the energy sector in general and the electricity sector in particular?

II. Barriers to entry by private investors
   » Is there regulatory uncertainty (eg, due to governments using energy as a regional development instrument; greenhouse gas abatement policies)?
   » Are there weaknesses in, and possible breaches of, competitive neutrality principles in practice?
   » Are non-commercial rates of return accepted by government-owned businesses?
   » Do government businesses make investments before these are warranted by market returns?
   » Is there poor signalling of government policy intentions concerning private investment?
   » Do retail price caps and other regulations constitute barriers to entry?

B. Potential weaknesses or inadequacies in the ‘rules of the game’

III. Market governance weaknesses
   » Are there conflicts of interest where governments are market players and policy makers?
   » Are there intra-market jurisdictional biases in terms of incentives, rewards and penalties?
   » Are there institutional inadequacies affecting market planners, operators and rule-makers?
   » Do the governance principles of accountability, independence, transparency apply?
   » For the NEM, do arrangements provide for a NEM-wide, technology-neutral focus? (The same questions can be asked in respect of other markets such as those in Western Australia and the Northern Territory.)
IV. Regulatory inadequacies concerning competition policy

» Is vertical integration a problem?

» Is horizontal aggregation a problem?

» Are the TPA and powers of the regulator adequate? What about other relevant legislation?

» Should there be special ownership rules in the electricity sector?

Both individually and collectively, these potential impediments, if significant, can undermine competitive pressures in the energy sector, impede adequate investment in energy capacity over time, raise costs and prices to customers, undermine governments’ capacity to respond to other pressing demands on their budgets, and even compromise energy reliability and system security.

They may even begin eroding the gains obtained from competition reforms already implemented.

Each of these possible impediments to competitive and efficient energy markets, if significant, can be dealt with by governments.

Government budgets as barriers to market entry

Large investments in additional electricity generation—at least $35 billion on some estimates—will be needed over the next 25 years.

For governments owning energy assets, this implies substantial additional pressure on the scarce resources available to them. Given looming budget constraints faced by governments, and rising demands on them, is additional investment by governments in energy supply the best use of such resources? If it is not, will government ownership of such assets prove to be a barrier to the needed increased investment in them?

The private sector could (and, on the evidence, would) make the necessary investment, provided the energy market is fully contestable. Governments themselves have indicated they have higher priorities. Privatisation of remaining government owned energy assets is an option.

In future, growing energy demand will require substantial investment to deliver growth in supply needed to maintain and improve market efficiency and reliability. For example:

» in its submission to the Commonwealth Government’s Uranium Mining, Processing and Nuclear Energy Review, ESAA estimated that, by 2030, additional installed generation capacity to meet Australian electricity demand growth would cost at least $35 billion (ESAA sub. no 203, page 2); and

» in its submission to ERIG in the Issues Paper, ENA indicated that energy distribution networks (gas and electricity) currently undertake investment of more than $5 billion per annum across Australia (ENA sub. No. 16, page 2).
Within Australia, most governments still own substantial electricity supply assets. This is especially so in NSW, Queensland, Western Australia, Tasmania, the Northern Territory and the ACT. It is not an issue in South Australia (and, with one exception, Victoria). The Commonwealth, NSW and Victoria jointly own Snowy Hydro Limited.

This can cause problems. For example it has been recognised by Australian governments of both political persuasions that:

» government owners of energy supply assets face an additional source of demand for scarce public sector resources. This can add to budget pressures as such governments seek to prioritise and balance competing demands for those resources. One risk identified by governments themselves arising from this tension is that they may not be in the best position to provide needed capital injections into the energy supply businesses to meet demand growth. This risk could constitute a barrier to market entry. This matter is covered in this sub-section of this chapter;

» such governments also face incentives to maximise returns from such businesses. This might lead to (i) excessive dividend extractions from such businesses relative to their investment requirements and dividend reinvestment needs; and (ii) an incentive to concentrate on protecting such businesses from full market competition to protect their earnings. This matter is addressed under the second barriers to entry sub-section below;

» in contrast, in some other cases, governments may be inclined to use such assets, and investment therein, to foster other economic and policy objectives, rather than deciding upon investments purely on the commercial merits of the case. This matter is addressed under the second barriers to entry sub-section below;

» more generally, all such governments face potential unresolvable conflicts of interest between their roles as (i) policy-makers, regulators and legislators supporting competitive market outcomes, and (ii) suppliers wishing to maximise profits. This matter is addressed especially under the governance and regulatory adequacy sub-sections below; and

» even where such governments do not wish to expand their energy supply activities, and are eager to signal that private investors can and should meet future demand growth, the adequacy of the signals given to the private sector can be a problem. In addition, ensuring a ‘level playing field’ between public and private energy supply businesses – competitive neutrality – can be a major problem. These matters are addressed under the second barriers to entry sub-section below.

Are budget constraints really a problem? ERIG considers these are likely to be a looming future constraint, even if less of a problem recently.

Using private investment in energy to help maintain hard-won budget discipline.

For some time during the 1990s and into the 21st Century, state and territory governments have gradually wound back public sector deficits and reduced public debt as a proportion of their respective economies. This trend has produced desirable effects. Credit ratings have improved as a result, mainly to AAA status, and this has paid dividends in terms of reduced borrowing costs for the governments involved. The Commonwealth has produced even stronger bottom-line budget results over the last decade as the economy has grown strongly, aided by strong commodity prices.
States and territories now seem to be facing a budget performance turning point, and the need for a sharper focus on where best to deploy scarce public sector resources to deliver the most efficient outcomes.

If publicly-owned assets such as electricity generation plants are constrained from growing by concerns about wider public sector resource allocation issues, both the electricity markets and other areas currently the responsibility of governments may suffer.

Even more than is the case at the commonwealth level, budget pressures are increasing for state and territory governments. Even in the near-term, these are already emerging (see table 5 below).

Key points shown in table 5 below are as follows:

- for states and territories as a whole, using official forward estimates, net operating balances are forecast to decline sharply from 2005-06 to 2009-10, averaging less than 30% of levels recorded in the last two years;
- for states and territories as a whole, using official forward estimates, there is also a turn-around of over $8 billion, from a surplus of $3.4 billion to a deficit of nearly $5 billion, in the total fiscal balance between 2005-06 and 2006-07; and
- as a proportion of Gross State Product (GSP), net debt for states and territories in total is expected to increase (or, equivalently, net lending is expected to decline) over the next several years. Included in these forecasts:
  - NSW is officially expected to move from a net lending position to an increasing net debt position;
  - Victoria’s net debt position is expected to increase;
  - Queensland's strong balance sheet position is expected to weaken, with its net lending falling as a share of GSP;
  - WA’s net lending position is less affected due to the commodities boom, but even here net lending as a share of GSP is expected to ease slightly compared with 2005-06;
  - South Australia’s net debt is expected to increase; and
  - in contrast, based on official forecasts, Tasmania, the ACT and the Northern Territory are forecast to reduce (increase) net debt (net lending) shares in GSP.

Based on widely-recognised current and future demands on governments (eg, as a result of population ageing, urban infrastructure renewal, water and other environmental investment needs) the need to more sharply determine priorities within State and Territory budgets will increase. ERIG believes that this rising pressure directly challenges the future efficiency and reliability of Australia’s energy markets, especially in states owning energy supply assets.
These pressures can affect economic efficiency in an Australia-wide sense, and governments’ contribution to that. They also have direct implications for economic efficiency in Australia’s energy markets.

In dealing with these challenges, ERIG believes that the following questions need to be answered by governments owning and operating assets in the energy sector:
1 Is continuing or future direct investment in, and operation by governments of, energy supply assets amongst the most efficient way to allocate their scarce public sector funds?

2 Should governments concentrate their limited resources on meeting their other, well articulated, pressing demands – for example, for investment in schools, hospitals, and other infrastructure?

3 Can the private sector—with appropriate policy and other signals—fill the electricity supply investment gap, freeing-up government resources for these other needs?

4 Can governments continue direct investment in electricity supply assets without future capital injections in electricity compromising investment in competing areas of urgent demand?

Ultimately, these questions must be answered by sovereign governments themselves. That said:

» In relation to the third question, ERIG has found no evidence that the private sector would not fill any electricity/energy supply investment gap, given a fully contestable market. On the contrary, ERIG has been advised that there is ample private investor interest in such assets. The recent purchase by Origin Energy Limited of Queensland retail energy assets, (including a reported $1.2+ billion for Sun Retail) appears to support this advice (see comments by Premier Beattie, 'States future growth fund gets a $1.3 billion kick', Queensland Government, 27 November 2006). Numerous comments to ERIG by private investors and market participants support the view that there is strong interest in energy sector investment, provided that governments do not undermine the contestability of the market. There has been some reluctance by such parties to ‘go public’ with such comments because of concerns about possible repercussions in some markets.

» In relation to the second question, and building on its observations on the third, ERIG judges that diverting scarce public resources away from ownership of energy assets and towards other goods and services which governments have recognised have larger ‘public good’ components – such as public health and education – would seem to be a sensible government response to looming budget pressures.

» In relation to the first question raised above, ERIG's judgement therefore is that the answer is ‘no’.

» As to the fourth question raised above, ERIG’s judgement is also that the answer is ‘no’.

Given that these questions must be answered by sovereign governments, there is an even more convincing source of evidence on these matters: the views of governments themselves.

ERIG’s opinions are most strongly supported by the revealed preferences of the government owners of energy supply assets in Australia. In almost all cases, they have signalled an interest in diverting their scarce resources away from energy supply (in whole or in part) and towards meeting other demands.

There are numerous statements by governments supporting this preference going back over almost a decade. A selection of these follows:
NSW energy assets

“The plan I have put to the party, the Government and the people of New South Wales is, as I have said before, a big bold Labor plan to unleash at least $22 billion of public assets tied up in electricity utilities and to reinvest those assets to deliver real practical benefits to the people and to the communities of New South Wales”.


“I like the proposition that we can shift our scarce public dollars from one area of investment into new areas of public sector investment. Redeploying, reinvesting in the public sector. I like that notion and its something that we want to pursue”.

NSW Premier Bob Carr, Channel 9 Sunday program, 31 August 1997.

“The sale of the industry would give to taxpayers of New South Wales an effective bonus of about $10 billion. That would enable us to pay off our entire State debt and have a significant amount left over for reinvestment in new social and economic infrastructure.”


Queensland energy assets

Queensland announces proceeds of energy assets sales to fund future infrastructure projects

“This is a great boost for the Queensland Future Growth Fund and our priorities of water infrastructure, clean coal technology and infrastructure projects like ports, rail and energy.”

Joint Media Release, Queensland Premier Peter Beattie and Treasurer Anna Bligh, 27 November 2006.

Tasmanian energy assets

“…if necessary, we will consider the sale of Transcend and Aurora. What has to be understood is that we are considering funding for a new hospital in the south and for improving hospital facilities in the north and northwest”.


Snowy Hydro Limited

“The NSW Government has decided it is no longer in the best interest of taxpayers to retain our 58% shareholding in Snowy Hydro. I want NSW taxpayers’ money invested in NSW hospitals, schools and police…I do not want to finance Snowy Hydro’s interstate ambitions with NSW taxpayer funds that could be otherwise spent on police, hospitals and roads.”


“The Snowy is a unique business...To grow, it needed capital investment in electricity businesses in Victoria and South Australia but, in public ownership, this would come at the cost of hospitals, schools and roads in NSW”.

NSW Premier Morris Iemma, National Press Club Address, Canberra, 1 June 2006.
“The Australian Government views the sale of its minority 13 per cent share as being in the interests of Australian taxpayers, and consistent with our strong support for the privatisation of government-owned electricity generators and increased competition in the electricity market, particularly in NSW.”


“The Government and now the Labor Party clearly understand that the sale of Snowy Hydro will allow the company to recapitalise and re-invest in its generation infrastructure, and allow more clean, green energy to flow into the national electricity grid.”

Senator Nick Minchin, Media Release, 30 March 2006

"I want that capital [from Snowy Hydro sale proceeds] for investment in NSW hospitals, schools and roads, NSW infrastructure and jobs in NSW."

NSW Premier Morris Iemma, Australian Associated Press, 2 June 2006 (Parenthesis added)

"If Snowy Hydro Ltd does not invest interstate, its competitors will and Snowy Hydro will face increased competition and lose market share"


In 1997, the majority view of the Committee of Inquiry into Sale of the NSW Electricity Assets was in favour of privatisation of those assets. The Committee was chaired by Mr Bob Hogg, AO, and Dr Tom Parry (Independent Pricing and Regulatory Tribunal - IPART).

In more detail, the majority view at that time included the following observations:

» the state government should not be providing large capital payments to Pacific Power or allowing it to significantly increase its borrowings to allow it to invest in a number of projects both within NSW and overseas;

» taxpayers’ money should not be put at risk in investing in these non essential development opportunities, a number of which could expose the state to significant risks which it could not control;

» this is in no way a commentary on the particular projects or plans or their prospects of success, but rather a reflection of the view that with scarce capital resources the state has higher priorities;

» it is not realistic to expect government to make further significant capital investment in the industry. The majority view is that no government with competing priorities for capital expenditure (such as hospitals, schools etc) is going to choose to invest large amounts of capital in risky electricity ventures. This is a significant disadvantage of continued government ownership;

» maintaining ownership of these assets, in the view of the majority, will lead to a decrease in their competitiveness and their returns to the state;

» there will not be funds available for social programs and infrastructure development from this source; and
» The majority supports the view that privatisation will not lead to decreased reliability of supply. The evidence simply does not support such a conclusion.

In December 2004, the NSW Government’s Green Paper Energy Directions for NSW was released for public consultation. A selection of statements from that document follows:

“The Government does not consider it appropriate to invest further capital in high risk commercial activities like electricity generation, when this capital and risk exposure can be provided by the private sector” (NSW Government 2004, page 46).

“The Government is committed to retaining the electricity assets it currently owns. However, it would prefer new investment in generation capacity to be financed by the private sector” (NSW Government 2004, page 3).

“The NSW Government will investigate ways of moving the electricity trading risk exposure of its retail businesses to the private sector” (NSW Government 2004, page 48).

“The NSW Government believes that encouraging private sector involvement in the NSW retailing sector (particularly for small customers) will provide a strong incentive for private sector investment in new generation plant in the State” (NSW Government 2004, page 48).

Summary

Government owners of energy supply assets have given clear signals about their preferences:

» they either wish to sell them, in whole or in part, and use the proceeds to deal with more pressing demands on their scarce resources; or, short of that

» they wish to curtail public sector investment in the energy supply sector, and rely on the private sector to meet future growth in demand.

ERIG agrees with the sentiment and logic in the various statements quoted above.

It seems clear to ERIG that if governments wish to focus their scarce resources on investments in areas other than energy assets, the private sector could appropriately and adequately fill the investment gap, given clear signals from governments, appropriate government policies and competitive market conditions.

Moreover, this would be a sensible allocation of the scarce resources of Australian states and territories.

ERIG findings and recommendation on budget barriers to entry

For governments owning energy supply assets, current and looming budget pressures appear to constitute a potential barrier to entry, curtailing adequate investment to meet energy demand growth in future.

ERIG has found no evidence that the private sector would not invest to meet energy demand growth given fully contestable market conditions. There is clear evidence to the contrary.

Government asset owners themselves have clearly revealed their preference either to sell their energy assets (in whole or in part) and/or curtail new investment in them, allowing the private sector to meet energy demand growth.
ERIG concludes that budget barriers to entry that might undermine competitive and efficient energy markets can be removed by governments privatising their energy assets as soon as possible, or at least by giving very clear signals that they will no longer invest in expansion of such assets.

**Market Structure Recommendations: budget barriers to entry**

ERIG’s recommendations for dealing with budget-related barriers to entry into Australia’s energy markets are closely related to its recommendations for dealing with actual or perceived barriers to entry faced by the private sector. All of these recommendations are presented together after ERIG’s findings on barriers to entry by private investors (see below).

**Barriers to entry by private investors**

There is a widespread view amongst investors and energy suppliers that ‘government’ (particularly some state government actions) constitute a barrier to private entry into energy markets.

This reflects policy uncertainty (eg, on greenhouse and regional development, retail price caps) and, in many states, government ownership.

The government ownership dilemma can be addressed by privatisation of all or significant parts of their energy assets or, failing that, reinforcing safeguards promoting competitive neutrality – a key requirement under the National Competition Principles Agreement – to ensure a ‘level playing field’ between public and private businesses.

The first of these options fully addresses the ownership problem. The second can only ever be a partial solution.

Investors and supply side participants cited ‘government’ as the most important barrier to private entry into energy markets. This was attributed both to government policy, and, in many states, to government ownership:

- on policy, greenhouse gas abatement policy and regional development policy were the main sources of investment uncertainty;
- specific government interventions, such as retail price caps, ETEF and LEP, also constituted barriers to entry. The first of these is covered later in this chapter. All are also examined in chapter 7 below.
- on government ownership, potential investors did not believe they faced a ‘level playing field’, or competitive neutrality: they believed government owned assets had an advantage over privately owned assets.

Some consumer groups, particularly the Public Interest Advocacy Centre, were more supportive of government ownership as a means for effective regulation of assets and prices and to protect the disadvantaged.

These issues are considered in more detail here.
Regulatory uncertainty, including on greenhouse gas policy

In many submissions to ERIG, and in a survey conducted for ERIG by KPMG, energy market investors have indicated that they need policy certainty to freely invest and to respond appropriately to investment opportunities as they emerge.

Investment in very long-lived assets such as generation and transmission can be subject to substantial changes in market conditions over the lives of the assets. Uncertainty about government policy can significantly affect investment decisions.

ERIG takes this to mean that investors want reasonable certainty about government policy. Without that, required risk premiums, and therefore required hurdle rates of return, will be higher, or investments will not proceed. Costs and prices for energy supply will rise, and competition will be less intense.

ERIG has been advised by potential investors in the sector that current policy uncertainty about greenhouse gas abatement is a major impediment to new investment, particularly in new base-load coal-fired plant. The current fragmented state-based greenhouse gas abatement policies are distorting and discouraging efficient investment. Investors want a more coordinated and sustainable policy approach.

Some investors also complained about state governments using energy investments as vehicles for promoting other policy objectives, accepting below-commercial rates of return, and, as a result, undermining private investments based only on their commercial merits.

Examples cited include use of government energy investments to promote state/regional development, and welfare objectives which are generally delivered via cross subsidies or regulation, imposing additional costs on the sector.

Competitive neutrality

The CPA, which formalised the recommendations of Hilmer (1993), set out the arrangements agreed by governments in relation to a number of competition-related matters, including competitive neutrality.

Competitive neutrality arrangements are intended to remove, or adjust for, advantages that government businesses may enjoy compared with private sector investments due to public ownership.

The effectiveness of these arrangements was most recently assessed by the Productivity Commission as part of its Review of National Competition Policy Reforms in 2005 (Report No. 33, April 2005). The Productivity Commission found rates of return for government business enterprises were mostly below commercial norms. It also found some shortcomings in the governance framework. In relation to these matters it found that:

“For those businesses which remain in public ownership, there is scope to improve both external and internal governance arrangements, as well as some opportunities to fine tune the competitive neutrality regime” (PC 2005, page 290).

In relation to competitive neutrality, the Commission concluded that:

“For the most part competitive neutrality elements of NCP have been implemented and appear to be working relatively smoothly” (PC 2005, page 293)
These general findings contrast with the widespread concerns expressed in ERIG submissions and consultations about government ownership of electricity assets.

The performance of governments in meeting their competitive neutrality obligations has been assessed every year by the National Competition Council (NCC). At its meeting on 10 February 2006 COAG signed the Competition and Infrastructure Reform Agreement which contains a number of initiatives designed to strengthen the competitive neutrality framework. Heads of Treasuries are doing further work in this area.

ERIG welcomes these initiatives. But the fact that these further steps are deemed necessary by the NCC is further confirmed by ERIG’s findings that there is still a ‘non-level playing field’ between government and private sector businesses.

ERIG has been advised by business of the following concerns about the operation of government business enterprises in the electricity sector (all can be viewed as breaches of the principles of competitive neutrality):

» barriers to entry where government owned energy assets dominate the market, limiting the ability of other private owners to compete by crowding out private investment;

» using government businesses to pursue non-commercial objectives and policies such as regional development or social outcomes, therefore creating a potential sovereign-risk for private investors;

» lower rates of return accepted by governments, therefore making it difficult for private investors to build a compelling business case to invest in competition with these government subsidised businesses;

» an advantaged cost of debt and a higher effective credit rating for prudential purposes compared with private companies, making it difficult for private investors to compete with these government businesses;

» advantaged decision making for government business enterprises;

» specific programs which advantage government businesses (eg ETEF, LEP, covered in chapter 7 below); and

» conflicts of interest between the policy and shareholder roles of governments where government is both umpire and player, and therefore at the very least creating the perception of the lack of a level playing field between public and private investments.

Each of these issues is considered in more detail below.

Before doing so, ERIG notes that, where government-owned businesses decide to invest in operations outside the jurisdictions governed by their owners, all of these distortions are magnified. This is not unique to energy investments. It can and does apply to other activities as well (eg, rail investments). While this matter has not been explored in detail in this report, the fact that such extra-jurisdictional investments occur increases market distortions and reinforces the case to deal with them comprehensively.
Do government businesses operate commercially?

ERIG sought evidence, from participants claiming a lack of competitive neutrality, that government-owned energy businesses do, or do not, operate on a fully commercial basis. The available evidence suggests very different situations between states, and in particular between NSW and Queensland.

Rates of return for government energy businesses: NSW

The NSW Auditor-General’s Financial Audit Report, volume 4, 2006 (see pages 41 to 77) indicates that:

- in 2005-06, government electricity investments produced a 15.2 per cent return on equity, compared with a national industry return for 2004-05 of half that rate (7.6 per cent) (NSW Auditor General 2006, page 43);
- the three state-owned distributor/retailers returned 16.1 per cent on average equity and a 9.4 per cent return on average assets in 2005-06 (NSW Auditor General 2006, page 44);
- the government-owned generators produced an 18.4 per cent return on average equity and 12.7 per cent on average assets (NSW Auditor General 2006, page 44);
- on transmission, TransGrid produced a rate of return of 7.4 per cent on average assets and 7.9 per cent on average equity (NSW Auditor General 2006, page 44);
- in 2005-06, the government received dividends and income tax equivalents of $1.2 billion from its electricity assets (NSW Auditor General 2006, page 45); and
- distributor payments to government as tax equivalents and dividends represented over 80 per cent of pre-tax profits and 10 per cent of gross revenues; generators paid about 75 per cent of pre-tax profits and 5 per cent of gross revenues and transmission about 30 per cent of pre-tax profits and 25 per cent of gross revenues. (NSW Auditor General, 2006, pages 43-45, 49, 50, 74-76).

These strong returns and high dividend payments come at a time when there will soon be a need for additional base load generation capacity in NSW.

The same NSW Auditor-General’s report (page 43) also indicates that:

- over the last five years the average daily spot price for electricity in NSW was significantly higher than in Victoria or in Queensland (NSW Auditor General 2006, page 43); and
- in 2005-06, NSW spot prices were more than 10 per cent higher than in Victoria and more than 20% higher than in Queensland. (NSW Auditor General 2006, page 43).

These comments from the NSW Auditor-General tend to support the evidence in chapter 4 above concerning energy market performance in NSW compared to other jurisdictions within the NEM. The spot price differential between NSW and Queensland is consistent with the apparently very different entry situation in Queensland (see next sub-section of this chapter).

ERIG concludes that this evidence of above-average rates of return, plus sustained higher spot prices in NSW than in connected jurisdictions, seems to be consistent with what would be expected in the presence of:
Reinforcing the view that returns for NSW generators are above what might be expected in a competitive market is the work done by the Productivity Commission in its Research Paper, *Financial Performance of Government Trading Enterprises 2000-01 to 2004-05*. That report compares financial indicators of government trading enterprises on a consistent basis. The rates of return on assets for NSW and Queensland generators are compared in Table 6.

### 6 Return on assets: government-owned generation 2004-05

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*Defined as percentage rate of return on assets*


Are these observations consistent with the private sector decision to build a new gas fired generation plant at Tallawarra and other proposals for new generation capacity in NSW which apparently are at various stages in the development and approvals process? NSW officials assert that the answer is ‘no’. That said, ERIG understands that the Tallawarra project is the only one which could be regarded as committed at this stage.

NSW officials have advised ERIG that ‘early’ investment by government owned businesses has not been an issue in NSW. On the basis of the (recent) evidence cited above, in the case of NSW, ERIG agrees. However, this is a diversion from the real market structures problem in NSW: barriers to entry by private investors despite sustained high price signals and strong returns.

As to the Tallawarra project, NSW officials indicated that the Government facilitated the project by giving the investors advice:

- clarifying the arrangements that would apply to its greenhouse gas emissions; and
- by undertaking that government businesses would not be investing in new generation capacity at the same time.

To the extent that this is an example of case-by-case incentives or guarantees to the private sector, ERIG concludes that it is not an efficient investment regime. A better approach is to allow full market contestability. In this environment, private investors can continually seek out sound investment opportunities that will meet the needs of their shareholders and potential customers, and efficiently invest to take advantage of these.
ERIG is aware that there is a public debate about whether or not the NSW Government is extracting excessive dividends from its electricity and other government-owned businesses. In this context, ERIG notes:

» reports that the NSW Government intends to increase dividends from its electricity utilities by $150 million over the next four years (Scott, ‘Iemma plans power raid to boost budget’, The Australian Financial Review, 22 November 2006, page 1);

» substantial additional base load generation requirements in NSW, over the next decade and a half;

» the NSW Auditor-General’s report indicating that the NSW Government has been increasing dividends from Sydney Water at a greater rate than the increase in net cash flows. Dividends increased by $73 million to $193 million at June 2006, while cash flows increased only $27 million to $287 million in 2005-06 (NSW Auditor General 2006, page 179); and

» the Auditor-General’s report that Sydney Water was anticipating paying a dividend of $140 million for 2006-07 (NSW Auditor General 2006, page 179).

These general dividend increases come at a time when the NSW Government faces large and growing demands for infrastructure investment, not only to meet growing demand, but also to repair and upgrade existing infrastructure assets.

Rates of return for government energy businesses: Queensland

The Queensland story appears to be very different from NSW.

International Power (IPRA) and Loy Yang Marketing (LYMCCo) submitted anecdotal advice that the target rate of return on Queensland government investments is in the range of 3-4 per cent, which is lower than either the Commonwealth bond rate or the 90-day bill rate.

In contrast, the Queensland Government advised ERIG that it expects a commercial return from its GOCs and ensures that its GOCs operate on commercial principles. However from ERIG’s perspective, the issue is not whether or not a commercial rate of return is expected. The key issue is what rates of return have been received.

Direct comparisons between rates of return on public and private companies are complicated by other factors.

If government businesses carry lower levels of debt than might involved in a comparable private investment, this might reinforce the view that rates of return are lower. ERIG notes the Productivity Commission, in its Research Paper, Financial Performance of Government Trading Enterprises 2000-01 to 2004-05, concluded that:

“Government ownership and government borrowing arrangements attenuate the incentives to maximise shareholder return and operational efficiency that flow from appropriate capital structures and market engagement” (PC 2006, page 2).

For state governments as shareholders, the return on investment includes the debt neutrality charge, company tax equivalent payments, dividends and sometimes capital returns.
The Firecone report to the Victorian Department of Infrastructure, provided to ERIG in response to the Issues Paper (submission no. 40), identified several examples of public sector electricity projects that others asserted were potentially uncommercial. These included a number of coal fired power station investments in Queensland.

Private investors asserted that these investments had been made earlier than would have been expected if these investments were made on purely commercial grounds, and that this constitutes a barrier to private investment because private investors do not have the same financial flexibility as governments to make investments earlier than is necessary and therefore reduce the average whole of life investment return.

Queensland officials state that these observations from market participants appear inconsistent with the significant private generation investment which has occurred in Queensland since 1998. They have indicated that this is more than has occurred in the privatised markets of Victoria and South Australia.

Queensland officials also claim that the state’s unique features, including rapid demand growth, the flattest load curve in the NEM, geographic differences and constrained import capacity, require significant reserve capacity to maintain a reliable and secure supply of power.

In relation to reliability, some private investors respond that there is no basis for remuneration of capacity in an energy-only market such as the NEM. Such investors argue that if governments invest for reliability they are subverting the reliability mechanisms in place in the market, and subsidising local capacity to the detriment of market participants as a whole.

ERIG does not have conclusive evidence that the investments identified in the Firecone report constitute uncommercial behaviour. But ERIG notes that there are divergent views about government investment activity in Queensland, and that perceptions, firmly held, can and do affect private investment decisions.

ERIG notes that firmly-held perceptions of government tendencies towards early investment in generation may be hampering private sector investment in Queensland, relative to what would have taken place in the absence of such perceptions.

**Financing costs for government business enterprises**

Many private sector participants are concerned about how governments finance their energy market operations. For example, in their submission to the ERIG Issues Paper, International Power Australia and Loy Yang Marketing summarised these concerns as follows:

“Government owned generation businesses have been assigned debt levels lower than would apply to privately owned businesses, making the required market prices at which they are sustainable, lower.”

“Government owned businesses generally hold investment-grade credit ratings, not through commercial performance of the businesses, but through either the government underwriting the debt directly, or as a result of banks perceiving the corporatised entities as less risky due to potential intervention by government in their ownership or regulatory capacity. This enables them greater opportunity to trade and hedge portfolios.”
“Government owned businesses effectively borrow money at lower rates than their private counterparts because of their state ownership, once again making their target revenues lower than equivalent private participants.” (International Power Australia and Loy Yang Marketing, sub. no. 22, page 3.)

However, ERIG notes that Clause 3(4)(b)(ii) of the CPA requires governments to impose debt guarantee fees on their business enterprises to offset any such competitive advantage. This clause requires:

“… debt guarantee fees directed towards offsetting the competitive advantages provided by government guarantees.”

The fee should equal the difference between the borrowing costs of a government organisation and a comparable private sector company.

A widespread view is that, in practice, the fee does not replicate market outcomes. The analysis in the box 2 summarises the fee-setting process adopted by the Queensland Government as an example.

ERIG is advised that actual GOC fee data is not available transparently to the market. However, the illustration above of the basis upon which the fee is determined raises practical problems. For example, ERIG wonders whether it is possible for individual government owned companies to obtain truly independent credit ratings.

**Box 2: Competitive Neutrality Fee – Queensland**

A key element of the Queensland Government’s competitive neutrality policy is the competitive neutrality fee that Government Owned Corporations raising debt pay to the Queensland Treasury Corporation. The process for determining the fee is set out below.

1. Each Queensland GOC is required to engage an independent credit rating agency to undertake a stand alone credit rating at least once every three years;

2. The stand alone credit rating is compared to the Queensland Government’s credit rating;

3. Queensland Treasury Corporation requests four banks to provide information on the relevant “margins” (the difference between the stand alone credit rating and the Government’s credit rating) across the yield curve. The lowest margin for each point on the yield curve is selected;

4. A margin for a GOC will be fixed for an agreed period and will apply to the majority of its debt. The GOC and Treasury ‘negotiate’ the margin taking into account the duration of the GOC’s debt, which may have regard to a forecast regulatory period;

5. If the GOC deems it necessary, separate margins may be applied to separate debt facilities;

6. A fixed competitive neutrality fee margin will continue to apply for the agreed term, irrespective of any changes to the GOC’s actual debt (including additional draw downs) and changes to credit ratings. This approach is adopted for ‘simplicity’;
7. The competitive neutrality fee is charged on actual borrowings and “financial arrangements” and is paid to Government;

8. The GOC has the option of applying the fee to either the book or market value of its debt; and

9. The ‘financial arrangements’ to which the fee is applied include:

   (a) all debt and ‘debt like’ obligations,
   
   (b) securitised transactions,
   
   (c) derivatives excluding electricity derivatives and those used by the Queensland Treasury Corporation to manage a GOC’s debt,
   
   (d) finance leases where the net present value of all finance leases is greater than 5% of non current liabilities, and
   
   (e) deferred payment arrangements.

On the face of it, the competitive neutrality fee arrangements create a level playing field from a cost of borrowing perspective. However, upon examining the detail of the arrangements it is apparent there are cost and risk management advantages for GOCs by virtue of their borrowing through a central government agency which benefits from the State’s sovereign creditworthiness. For example:

1. Private sector borrowers develop their borrowing strategy utilising the yield curve, accessing individual debt facilities that each attract different costs based on, among other things, liquidity and term. The term of the borrowing will be related to the term of the underlying asset or arrangement that is being funded as well as the borrowing and risk management strategies of the Board. These directly impact on the final cost of debt. The GOC, on the other hand, is effectively insulated from the realities of individual company borrowing. Because the fee is fixed regardless of its actual portfolio adjustments, the GOC does not see the margin costs of:

   (a) individual borrowing, which captures particular market circumstances at the time;
   
   (b) matching the individual borrowings as required with the Board’s risk management strategies; nor of
   
   (c) draw downs or restructuring its facilities to either optimise market conditions or maintain their arrangements within Board approved guidelines.

2. The fee arrangements do not take into account additional costs borne by the borrower (for example, through lack of liquidity) as part of achieving a particular ‘duration’ for its debt. Instead, the Treasury Corporation borrows across the yield curve for all its clients and any margin costs of restructuring an individual GOC’s portfolio do not translate through to the fee calculation. The simplification of the fee calculation results in the GOC being exempt from the realities of the borrowing market and the costs associated with readjustments that would be contained in the fee component of the borrowing cost.
3. The fee arrangements do not track changes in the market or cost differentials arising from changing individual borrowings over time, for example increasing borrowings to reflect project developments, and the particular market conditions at the time. The fee calculations are static for a GOC, allowing the GOC to select or optimise outcomes that do not replicate market outcomes, for example the GOC can fix the fee for a period of time and base its application on the book value of debt.

Adequacy of government signals for private investment

State governments owning energy assets have increasingly sought to signal their desire for private sector investment to meet future demand growth.

ERIG notes such signals are often ambiguous, particularly when combined with subsequent government action to undertake new investments themselves, or where governments also signal they will be ‘investor of last resort’. For the private sector, the key criterion is policy certainty.

ERIG believes sending clear and unequivocal signals encouraging private energy investment is crucial.

This contrasts with what seems to be the mixed signals for potential investors in the NSW energy sector. In its Energy Green Paper Energy Directions for NSW, released in 2004, the NSW Government indicated it wished to rely on the private sector for future investment in electricity, but reserved the right to undertake further investment itself if that were necessary (NSW Government 2004, page 3).

ERIG agrees with the comments made to it by potential private investors in the NSW energy sector that such a statement could be ambiguous to private investors and will potentially deter or delay investment.

The Government of Western Australia appears to be following a more effective signalling strategy. A Ministerial directive caps Verve Energy (the dominant government owned generator in the WEM) generating plant at 3000MW. There are further limits on the potential market expansion of government owned market incumbents in other sectors within the Western Australian energy market.

This appears to be sending a clearer message to the private sector about the intentions of the WA Government, and the expectation that the private sector is expected to invest to meet growth in market demand.

Even so, the WA strategy may not be optimal. For example, ERIG understands that government-owned businesses such as Verve Energy cannot sell off some of their capacity to place them below the capacity caps so that they can compete for market growth in future. In the interests of promoting more competition within the WEM, this option might be worth considering.
Retail price caps as barriers to entry

Demand-side issues are part of other work programs being dealt with by the MCE. ERIG does not intend to make other than process recommendations in this area, apart from encouraging the MCE to proceed expeditiously.

The discussion here relates solely to demand side issues relevant to ERIG’s market structures terms of reference.

ERIG has received submissions from users arguing for lower price caps—for example in relation to VoLL, or retail price caps—and other retail regulation, in the context of energy only markets such as the NEM. On the supply side, investors have argued that some retail price caps are binding and that VoLL may not be set high enough to bring forward sufficient investment.

Particularly for energy only electricity markets, suppressing or dampening price signals is risky. It either destroys or diminishes efficient signalling of the need for new supply. Price is the most efficient signalling device of the need for new investment. Suppressing price signals is a barrier to entry, reducing market competitiveness and efficiency.

Allowing some prices to move relatively freely, while capping others, does not solve this problem. For example, capping retail prices while leaving wholesale prices relatively unconstrained can squeeze retailers between price caps for their customers and the costs they pay for wholesale electricity supply.

This distortion (seen to an extreme degree in California some years ago) can induce other distortions, all of which either raise costs and prices, and/or deny reliable supply, either generally, or to some disadvantaged groups.

These distortions may include:

» failure to provide the same services to particular groups in the community;

» an even greater degree of vertical integration between generators and retailers than would otherwise be deemed commercial;

» greater reliance on purchasing financial market risk management instruments than would otherwise be undertaken, adding further to costs;

» cross-subsidisation between electricity market segments (eg, generators’ returns being used to cross-subsidise retailers’ compressed returns); and/or

» limiting the commercial attractiveness of government-owned retail businesses in situations where governments might desire to privatise such businesses; and thereby, at best, reducing sale proceeds for governments.

Allowed retail margins across the jurisdictions are shown in table 7 below, prepared by KPMG. Based on table 7, South Australia, the ACT and Victoria have the highest allowed retail margins. This may have facilitated new retail entry.

Viewed as barriers to entry impeding competitive and efficient electricity markets, ERIG considers that binding price restrictions and caps, as a general rule, should be removed as quickly as possible. The existence of binding retail price caps negates the benefits that would be derived from the introduction of full retail contestability across the NEM.
7 Allowed retail margins across jurisdictions

<table>
<thead>
<tr>
<th>Jurisdiction</th>
<th>Year</th>
<th>Net margin %</th>
</tr>
</thead>
<tbody>
<tr>
<td>South Australia</td>
<td>2005</td>
<td>5</td>
</tr>
<tr>
<td>New South Wales</td>
<td>2004</td>
<td>2</td>
</tr>
<tr>
<td>Victoria</td>
<td>2003</td>
<td>5</td>
</tr>
<tr>
<td>South Australia</td>
<td>2003</td>
<td>5</td>
</tr>
<tr>
<td>Tasmania</td>
<td>2003</td>
<td>3</td>
</tr>
<tr>
<td>Australian Capital Territory</td>
<td>2003</td>
<td>5</td>
</tr>
<tr>
<td>New South Wales</td>
<td>2002</td>
<td>1.5–2.5</td>
</tr>
<tr>
<td>Victoria</td>
<td>2001</td>
<td>2.5–5</td>
</tr>
<tr>
<td>New South Wales</td>
<td>2000</td>
<td>1.5–2.5</td>
</tr>
<tr>
<td>Tasmania</td>
<td>1999</td>
<td>12.5</td>
</tr>
</tbody>
</table>

Source: KPMG

Australian Governments have agreed to a process for removing retail price caps, through the MCE. However, this is conditional upon governments being satisfied there is sufficient competition in electricity markets. In this context, ERIG notes statements made by the South Australian Energy Minister, which include the declaration that removing retail price caps “is just silliness” (Bildstien, 2006, ‘Scrapping price caps ‘silliness’, The Advertiser, 22 August 2006).

ERIG agrees with the decision to remove retail price caps, and the introduction of full retail contestability in accordance with the MCE work program. ERIG encourages the MCE to move as quickly as possible, and seeks to contribute by making recommendations that will improve competition in electricity markets.

That said, ERIG notes there is a potential contradiction inherent in the agreed MCE process. Retail price caps may be either (i) higher than actual market prices, or (ii) binding (that is, actually constraining market prices).

In case (i), price caps are effectively redundant – regulation imposing some ‘red tape’ costs but otherwise not affecting market outcomes.

In case (ii), where price caps are binding, ERIG concludes that governments responsible for such restrictions face a dilemma. In such cases, there are government policy-induced competition problems:

» retail price caps and retail price restrictions are effectively barriers to entry, impeding the bringing-forward of efficient supply;

» such price controls themselves are impediments to competitive and efficient electricity markets; and

» if the emergence of competition is a prerequisite for removal of retail price caps that themselves impede competition, this is a Catch-22 situation.

ERIG encourages COAG and the MCE to revisit this process and to deal with this inherently contradictory situation as soon as possible.
Where retail price caps are intended to assist disadvantaged groups, ERIG concludes that the best way to deliver that assistance should be determined. Delivery of Community Service Obligations (CSOs) is probably best handled through explicit and conditional transfer payments from government budgets to the appropriate recipients, because:

» CSOs should be funded by the community, out of general tax revenue;

» this allows precise targeting of payments to those deemed to be in need; and

» this avoids unintended supply-side effects that impact most on those most in need (eg, it avoids the problem of retail price caps and/or regulation leading to reduced incentives to provide the same extent of competitive service to such groups).

Dealing specifically with the agreed MCE process on retail price caps, ERIG judges there would be benefit in some refinement to that process along the following lines:

» seek to advance the process of improving competition, and gradually lifting retail price caps to levels where they are less binding, as a simultaneous, but phased, approach to improving overall market competition at the retail level. This directly addresses the ‘Catch-22’ problem noted earlier;

» where possible, consider shifting some, or even all, of government CSO delivery objectives to budget transfer payments;

» ideally, specify a transition path for this process, with up-front timelines for its achievement; and

» during the transition process, respond adaptively to adverse market developments as they emerge, maintaining dialogue with market participants, (who will be aware that regulatory powers could be invoked, if needed), and providing broad guidance about what is acceptable, preferably by agreement with them.

ERIG believes that these refinements offer the chance of a minimal-risk market evolution to more competitive outcomes, over a set time-frame, with the capacity to respond to market developments during the transition. ERIG understands that such a process has been implemented in Victoria.

Other barriers to entry

The private sector has claimed that there are other significant barriers to entry into the Australian energy market.

New South Wales is the example most often cited. Private investors have raised the following claims:

» ETEF provides a risk management tool to government entities which is not available to the private sector. The arrangement distorts the financial market and reduces liquidity. The NSW Government has committed to the phasing-out of ETEF. (ETEF is considered in more detail in chapter 7);

» retail prices have been set below cost for many franchise load customers, inhibiting effective competition from private retailers. That retail prices are below cost has been acknowledged by IPART at the last two regulatory resets and in the latest IPART determination. ERIG notes that this issue has been recognised and there is action to address it.
Reducing barriers to entry, whether actual or perceived

ERIG concludes that government ownership of electricity assets is indeed an underlying source either of:

» actual; and/or

» perceived barriers to entry by the private sector.

ERIG concludes there are three broad options for dealing with the problem:

» first, where the problem is one of perceptions, governments as electricity asset owners must comprehensively dispel such misperceptions, by releasing hard evidence refuting the various assertions reviewed above. This is desirable from transparency and competitive neutrality perspectives, anyway. It is essential for market efficiency;

» second, disaggregation (ie, breaking down businesses into a larger number of smaller participants) of government-owned electricity assets, and then privatisation, could be considered. This might be more feasible for some market segments, and for some (larger) jurisdictions, than for others. For the contestable markets (generation and retail) this could help improve competition and reduce costs to consumers. For the regulated markets (transmission and distribution) it might be argued that privatisation is a lower priority. However, that depends on whether such assets, regardless of ownership, can be effectively regulated; and

» third, where privatisation is not considered acceptable, a range of supporting initiatives to improve competitive neutrality should be considered. Seven such initiatives are reviewed below.

Disaggregation and privatisation of government-owned electricity assets has a number of advantages. Reliance on private sector investment reduces the risk profile of the state and this option would immediately release a substantial body of funds that could be used for other social policy priorities which are not always amenable to provision by the private sector. These include health, education, public transport and other infrastructure needs. Governments in the past themselves have acknowledged these advantages.

Privatisation of contestable market assets also has the advantage of separating these from the natural monopoly segments.

The recent decision by the Queensland Government to sell its electricity retail and gas distribution network businesses and the reported consideration being given by the Tasmanian Government to possible sale of its retail assets are good examples of such initiatives.

Some state and territory governments have ruled out privatisation of some or all of their energy assets. Where privatisation is not pursued other actions (see the third option noted above) will be necessary to address current problems.

At its meeting on 10 February 2006 COAG agreed to:

“…enhance the application of competitive neutrality principles to government business enterprises engaged in significant business activities in competition with the private sector…”
ERIG concludes that the following seven initiatives should be implemented for government businesses operating in the energy sector:

1. **All debt to be funded through commercial mechanisms without government guarantees**

   Funding from commercial sources rather than through treasuries would help to establish businesses on a commercial basis.

   This would go some way to removing the imperfections of the current debt guarantee fees. Even so, with government ownership, any implied guarantee arising from that ownership will still confer an advantage relative to privately-owned businesses.

2. **Electricity corporations to be subject to the Corporations Act 2001**

   Although government owned electricity businesses have been corporatised, in some cases they are not subject to the Corporations Act (see ‘regulatory adequacy’ sub-section later in this chapter).

   The Corporations Act requires directors to act in the best interests of the company, facilitating greater independence and commercial decision making. This should be accomplished through the necessary legislative changes.

3. **Electricity corporations should pay all government taxes and charges, including company tax, with arrangements to be entered into between the relevant State Governments and the Australian Government on the rebate of company tax to the latter.**

   This ensures that the commercial incentives faced by the electricity corporation (and its government owner) are aligned with those faced by private sector operators.

4. **Establishment of independent mechanisms for board appointments**

   Existing competitive neutrality arrangements provide that the nominees for board appointments for government owned businesses are selected on the basis of skills required by the board.

   In fact, governments typically choose board members.

   A possible approach would involve the board of the electricity corporation providing a list of candidates to the government shareholder for consideration, rather than having the shareholder choose its own candidates (see ‘governance’ sub-section below).

5. **The level of dividends should be determined independently by the board based on the long term requirements of the corporation.**

   Having autonomy and flexibility in setting dividends enables an organisation more efficiently to manage its financing operations.

   It will reduce criticisms that government dividend policies have prevented government business enterprises from undertaking required capital expenditure in a timely manner.
6. Corporation reporting to governments on activities to reflect ASX listing rules

While board and management should possess operational autonomy in the day-to-day operations of the business, an appropriate accountability framework is also required.

The ASX listing rules require full disclosure of activities which have a bearing on the operations of the business without loss of autonomous decision making. These rules should be applied to government businesses as well.

7. Independent decision making by government owned enterprises

As entities with independent boards, governance arrangements should be such that the Boards are able to make independent decisions about key operational and strategic management directions.

In contrast, as an example, risk management policy currently appears to have been set centrally, at least in NSW, rather than allowing the Board to determine its individual approach. This matter is also addressed under ‘Governance’ below.

The proposals outlined above, if implemented fully, help to reduce some of the concerns raised by private sector operators in the electricity industry. But they are not perfect.

Government businesses do not face the same efficiency constraints that a listed company faces. Poor decisions made by publicly listed private entities impact on the shareholders. In the public sector they are borne by the taxpayer. Publicly listed private companies face continuous scrutiny of their ability to maximise the capital and dividend returns to shareholders, and share prices reflect performance. A poorly performing private sector company faces a greater risk of takeover and management replacement.

Snowy Hydro Limited is a case study to which all of the issues associated with barriers to entry and competitive neutrality apply (see box 3).
Box 3: Government ownership – the case of Snowy Hydro Limited

The governance, competitive neutrality, legislative and regulatory structures under which Snowy Hydro Limited was established were designed to replicate, as far as possible, the arrangements for a listed private sector company. The arrangements largely conform to the seven proposals outlined above. The purpose of the arrangements was to enable Snowy Hydro Limited to pursue commercial opportunities, as identified by its independent board, and to facilitate competition in the national electricity market.

The challenges and limitations faced by a government owned company operating in the competitive electricity market were highlighted during the recent abandoned privatisation of Snowy Hydro Limited. In this regard, the shareholder governments had made it clear that they did not wish to be placed in a position of funding the future growth of the business. This highlights the substantial constraints placed on a public company to fund investments where its government owners are unwilling to inject additional capital. A private sector business does not face the same constraints as it can seek additional funds from shareholders or debt markets.

The recent NSW Legislative Committee Inquiry into the Continued Public Ownership of Snowy Hydro Limited (2006) acknowledged the risk for the company of losing relevance in the market if it is unable to pursue growth.

Constraints on growth are unlikely to be a problem under a stable market structure with few growth opportunities. The Australian electricity sector, however, is a dynamic and growing market, with investment announcements being made on a regular basis. In such an environment, any business which lacks the capacity to fund its capital expansion needs will face, over time, a gradual erosion of its market position and a decline in shareholder value.

ERIG notes that governments have decided that the unique features of the Snowy Mountains Scheme, as a combined electricity generation and water storage system, have justified its continued government ownership at this time. In the longer term, and especially as the budget pressures faced by governments increase, ERIG considers that the limitations inherent in ongoing government ownership can best be resolved through privatisation. In the longer term, ERIG considers that a suitable privatisation model that would enable Snowy Hydro Limited to prosper while protecting water and environmental interests should be developed.

In the interim, the same unique attributes of Snowy Hydro, which have been argued warrant the retention of government ownership, do not justify a more interventionist approach by shareholder governments in the company’s activities. While Snowy Hydro remains in public ownership ERIG is of the view that it is incumbent upon the shareholder governments to affirm its commercial independence and grant the board and management the freedom to pursue commercial opportunities in the market and to conduct all regulatory activities at arms length.

See also comments on Snowy Hydro in chapter 7 below.
ERIG findings on barriers to entry by private investors

ERIG has been struck by the consistent refrain that ‘government’, particularly some state government actions, constitute a barrier to private sector entry into energy markets.

Government policy and government ownership of competing businesses are the two sources of such barriers.

Policy on greenhouse gas abatement is a key source of investment uncertainty.

Government regulation of energy prices (eg, retail price caps) can be a barrier to private entry into energy supply markets.

Use of government-owned assets to drive other government policy objectives is a barrier to entry in some cases.

Government ownership in some jurisdictions causes concerns about competitive neutrality. Perceptions held by private investors that there is no ‘level playing field’ directly threaten full market contestability.

The evidence suggests barriers to private entry can take different forms in different states.

In NSW, the dominance of government-owned energy businesses, plus some evidence suggestive of sustained albeit intermittent market power, plus the failure of new entry despite price signals for it, suggests that investment is being delayed or prevented compared with what would occur in a fully contestable market.

In Queensland, the problem is different. Government investments, if anything, appear to be undertaken too soon, because of official concerns about reliability (and possibly other state development objectives) making private investments uncommercial.

ERIG concludes that privatisation is the most efficient and effective solution to most of these problems. If governments retain ownership of energy assets, then initiatives to improve competitive neutrality should be implemented immediately. Even so, these will only be imperfect solutions.

On retail price caps, ERIG notes the agreed MCE processes. However, ERIG also concludes that there is an inherent contradiction between (i) waiting for the emergence of competition before removing price caps, and (ii) the fact that price caps themselves can be impediments to competition.

ERIG concludes that COAG and the MCE should address this inherent contradiction as soon as possible.
Market Structure Recommendations: dealing with barriers to entry

The following recommendations are designed to improve the efficiency of Australia’s energy markets by removing barriers to entry.

1. Improving market contestability and efficiency

The following recommendations are intended to improve contestability and efficiency in Australian energy markets. The first five are presented in ERIG’s descending order of preference.

1.1 Privatisation of all energy supply assets

ERIG recommends disaggregation and full privatisation of government-owned energy assets throughout Australia, as soon as is feasible given the practicalities of the privatisation process.

This recommendation potentially applies to NSW, Queensland, Western Australia, Tasmania, the Northern Territory, the Australian Capital Territory, and to the government owners of Snowy Hydro Limited.

Given the dominance of NSW (33%), Queensland (28%) and Victoria (26%) in terms of generation output shares within the NEM, the efficiency benefits from this recommendation depend most heavily upon implementation within NSW and Queensland (Victoria having already privatised its energy supply assets).

ERIG acknowledges that the small size of the ACT and Northern Territory markets may militate against significant gains from disaggregation in the Territories, although privatisation plus appropriate regulation may still be desirable over time.

ERIG regards this is a ‘first best’ recommendation. In part at least, it is not consistent with current government policy in NSW, Queensland, Western Australia, Tasmania, the Australian Capital Territory, the Northern Territory and for Snowy Hydro Limited.

1.2 Privatisation of some energy supply assets

Where recommendation 1.1 is not considered feasible at present, ERIG recommends disaggregation and privatisation of some electricity assets, such as those in the contestable market segments (generation and retail), as soon as is feasible given the practicalities of the privatisation process.

ERIG welcomes the decision by the Queensland Government to privatise its retail electricity assets, and notes public statements by the Tasmanian Government about the possibility of a similar initiative.

This recommendation potentially applies to NSW, Queensland, Tasmania, Western Australia, the Northern Territory, the Australian Capital Territory and to the government owners of Snowy Hydro Limited. That said, ERIG acknowledges that the small size of the ACT and Northern Territory markets may militate against significant gains from disaggregation in the Territories, although privatisation plus appropriate regulation may still be desirable over time.
1.3 Encouraging private investment in energy
Where recommendation 1.1 is not considered feasible at present, but where Governments, for budgetary reasons, do not wish to allocate additional public resources to investment in electricity assets, ERIG recommends that the clearest possible signals be given to the private sector that it will be permitted to invest, on a ‘level playing field’ basis, to meet forecast demand.

ERIG considers that Western Australia has given relatively clear signals to date. Enshrining these in legislation, beyond Ministerial Directions, and allowing incumbent government businesses to sell down assets to allow them to compete, may make signals even clearer. Other States, notably New South Wales, could improve the clarity of signals currently presented to the private sector.

ERIG notes that, even when effective, this ‘hybrid’ model, where both public and private sector ownership exist in competition, increases tensions between government- and privately owned businesses. This intensifies the need for effective governance arrangements and genuine competitive neutrality (see below).

This recommendation potentially applies to NSW, Queensland, Tasmania, Western Australia, the Northern Territory, and the Australian Capital Territory. ERIG acknowledges that the small size of the ACT and Northern Territory markets may militate against significant gains from new investment by the private sector in those markets because of the ‘lumpiness’ of investment, at least until there have been significant increases in demand. Contestability for the ACT market entails supply from elsewhere in the NEM, anyway.

1.4 Disaggregation of government electricity assets
Where recommendation 1.1 is not considered feasible at present, ERIG recommends disaggregation of government-owned electricity assets. That said, ERIG is sceptical about whether disaggregation, and continuing government ownership, will provide significant benefits. For it to do so, further reforms enhancing competitive neutrality and improving governance arrangements will be crucial (see below).

This recommendation potentially applies to NSW, Queensland, Western Australia, the Northern Territory, and the Australian Capital Territory. It may be of particular value in NSW, if competitive neutrality arrangements can be improved (see below).

ERIG acknowledges that the small size of the ACT and Northern Territory markets may militate against gains from disaggregation in the Territories.

1.5 Strengthening competitive neutrality safeguards
Where recommendation 1.1 is not considered feasible at present, ERIG recommends strengthening of safeguards for competitive neutrality between government- and privately-owned energy businesses.

These cannot fully deliver competitive neutrality, but they can improve on the status quo.

Specific competitive neutrality recommendations under recommendation 1.5 are set out below (see also recommendation 3.1 below). These recommendations potentially apply to NSW, Queensland, Tasmania, Western Australia, the Northern Territory, the Australian Capital Territory and Snowy Hydro Limited:
1.5.1 All debt to be arranged through commercial mechanisms, eliminating explicit benefits (and minimising implicit benefits) from perceptions of government guarantees.

1.5.2 State-owned Electricity Corporations to be subject to the Corporations Act 2001.

1.5.3 Electricity Corporations to pay all government taxes and charges, including company tax, with state governments to receive no company tax advantages from company income generated by such businesses.

1.5.4 Board appointments to be independently determined, based on appropriate skills for appointment.

1.5.5 Dividend payout policy to be determined by the board based on commercial requirements for the business in question, rather than by government decision.

1.5.6 Corporations to report to governments on their business activities in compliance with ASX listing rules.

1.5.7 Independent decision making on operational and strategic management directions by government owned enterprises.

1.6 Retail price caps as barriers to competition

The MCE has agreed retail price caps should be removed after competition exists in electricity markets. ERIG concludes there is an inherent contradiction between (i) waiting for competition to emerge before removing price caps, and (ii) the fact that binding price caps themselves constitute impediments to competition.

ERIG recommends that this contradiction be reviewed and resolved, either by COAG and/or by the MCE. The Victorian practice of fostering competition and easing price caps simultaneously may be a useful guide to solving this problem Australia-wide.

ERIG also recommends that governments conduct a detailed review of CSO arrangements, directed to delivery via non-distorting, transparent and targeted mechanisms in place of such ‘blunt instruments’ as retail price caps.

These recommendations apply to COAG and most States and Territories.
Market governance

Overview

Good governance principles – ensuring no conflicts of interest, clearly allocating responsibilities, getting incentives ‘right’ – are relatively easy to enunciate and are an important means for securing Australia’s energy future.

Australia’s energy market governance arrangements have been improved as a result of reforms implemented over the ‘90s and into the 21st century.

However, ERIG believes that further refinements can and should be made to support the emergence of a truly national and efficient energy market in Australia.

Ensuring contestable market structures and appropriate regulation of competition (see below) are necessary, but not sufficient, conditions for fostering competitive and efficient market outcomes.

Electricity market governance must be “right” as well. Good governance requires:

» a clear allocation of roles and responsibilities between relevant entities, notably responsible governments, and the organisations charged with planning, operating and regulating the electricity market; and

» making sure that the incentives (rewards and penalties) that operate in practice are designed to encourage efficient market outcomes, where “market” is defined appropriately.

Governments have a responsibility to foster competitive markets to deliver efficient supply of goods and services to their citizens. A core function of governments is to set in place rules and requirements for how markets can operate. These rules must promote competitive markets.

Governments should not do anything that is in conflict with these rules.

ERIG’s governance analysis rests on the following basic principles for good governance arrangements in Australia’s electricity markets.

Basic governance principles

I. Conflicts of interest, whether actual or perceived – especially affecting governments where they are (i) policy makers; (ii) regulators or rule initiators; and (iii) market participants – should be eliminated altogether.

II. Any intra-market jurisdictional biases, favouring jurisdictional decisions over market-wide decisions, should be eliminated.

III. A clear and efficient allocation of responsibilities for policy, market planning, market operation, and regulation across appropriate entities should be put in place.

IV. Given the first three principles, the usual requirements of independence, accountability, and transparency should apply to responsible organisations:
**Independence** – parties with commercial interests in the outcomes of a function are not given responsibility for that function. This also extends to conflicts of interest across functions (for example where responsibilities and accountabilities for one function can be managed through another function);

**Accountability** – parties responsible for functions are accountable for their performance and the outcomes generated; and

**Transparency** – parties responsible for functions and/or holding information (which is not commercial-in-confidence) face obligations which ensure transparency. This supports accountability and a level playing field.

Especially from a NEM-specific perspective, but also, as far as possible, for other markets such as the WEM, these broad principles lead to more specific criteria in the case of Australia’s electricity markets (and energy markets more generally). These include two key market features:

- a fully national, or at least market-wide, focus – governance structures should underpin a national or market-wide approach to the development of the system; and
- technology neutrality – governance structures should ensure that the most economically efficient solution is forthcoming, thereby protecting long term allocative efficiency.

Most of these principles can be summarised in an electricity market context via the illustrative framework in figure 11 presented below.

These market governance arrangements could be applied, in whole or in part, within the NEM, the Western Australian market, or the Northern Territory market. The template presented in figure 11 can be used as a guide to good governance outcomes in Australia’s electricity markets.

### 11 Governance arrangements

<table>
<thead>
<tr>
<th>GOVERNANCE TEMPLATE</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>BROAD ENERGY POLICY FORMULATION LEVEL</strong></td>
</tr>
<tr>
<td>(Efficiency, Reliability, CSOs, etc)</td>
</tr>
<tr>
<td>Responsibility for giving effect to policy is delegated.</td>
</tr>
</tbody>
</table>

| SYSTEM PLANNING, OPERATION & REGULATION LEVEL |
| (Delegated full power to implement government policy) |
| Includes AEMC, NEMMCO, and ACCC (AER) – for the NEM. |
| Split between IMO and ACCC (AER) – for the WEM |
| All these bodies must be genuinely independent authorities. |

| ENERGY MARKET PRODUCT PARTICIPANTS LEVEL |
| CONTESTABLE SUPPLY |
| Seek full contestability. |
| Minimise market power. |
| Disaggregate supply. |
| Minimise or eliminate government ownership. |
| Competition safeguards. |
| REGULATED SUPPLY |
| Any reg. test applies at the planning level. |
| Transmission & distribution investments by competitive tender (both cost and ROI). |
| DEMAND SIDE |
| Allow full price signals to flow to users. |
| Load-shedding incentives driven by market. |
| Incentives for ‘smart metres’ and more energy efficient equipment. |

Signifies functional independence between levels.
Features of good governance not fully observed in Australia

Two key features of good governance set out above are:

- no actual or potential conflicts of interest; and
- clear separation of policy making functions from market operation functions.

Conflicts of interest: government ownership

The first feature does not apply consistently throughout Australia.

For those governments with either partial or substantial government ownership of electricity supply assets, there is either the potential for a conflict of interest, or an actual conflict of interest between their roles as policy makers, regulators and energy asset owners.

At the present time, this conflict of interest exists (by size of market investment) for:

- NSW (including Snowy Hydro);
- Queensland;
- Western Australia;
- Tasmania;
- The Northern Territory;
- The Australian Capital Territory;
- Victoria (Snowy Hydro);
- The Commonwealth Government (Snowy Hydro).

The most effective solution to this problem is removal of the conflict via full privatisation by governments of all energy assets. An imperfect alternative is to make competitive neutrality provisions more effective.

Conflicts of interest: jurisdictional versus market-wide interests

There is also a potential conflict of interest between jurisdictional (state) interests and market wide interests. This is only likely to be a significant issue within the NEM. The Western Australian and Northern Territory electricity markets lie wholly within those jurisdictions, and are therefore appropriately covered by the respective State and Territory Governments.

But for the NEM, five States, one Territory and the Snowy Hydro region (currently owned by three Governments) are involved.

It is possible that governments with jurisdictional responsibilities confined to regions lying within the NEM are more likely to act in ways helpful to their sub-NEM jurisdictions than in the interests of the NEM as a whole.

Were Australia to have a genuinely national electricity market into which all States and Territories were connected, then there would be a case for allocating the government
policy role to the Commonwealth Government, in order to ‘internalise’ the market within the geographic scope of Commonwealth responsibilities.

Short of that—and accepting the state-based genesis of Australia’s electricity markets—there is a strong case for significant Commonwealth Government participation in decision making as a representative of the interests of the market as a whole (for example, to support efficient inter-state trading in electricity where that made sense from a market-wide perspective).

Given that the NEM represents approximately 93 per cent of total Australian electricity supply (ESAA, 2006, page 16-17), ERIG considers that this argument could be applied with almost equal weight to the NEM. By ensuring that the NEM lies within the area of responsibility of one government, the potential jurisdictional conflict noted above could be eliminated or reduced.

At present, the Commonwealth does have a voice on energy market matters through the voting rules for the MCE.

Clarifying the allocation of roles and responsibilities

As to the second key feature of good governance, it is important to allocate responsibilities for the following functions clearly:

» policy making;
» market planning;
» market rule-making;
» market operation; and
» market regulation.

The first of these functions should be a matter for governments. The others—all dealing with the detail of market operation—should not. They should be undertaken by independent and accountable organisations charged with responsibilities to meet clearly-specified government policy objectives.

These functional allocations are considered in more detail in what follows. Suffice it to say here that, in some parts of Australia, government involvement extends well beyond broad policy making, and well into day-to-day market management. It is probably no coincidence that this is most evident in jurisdictions with substantial government ownership of energy supply assets.

Broad policy making function: a matter for governments

Broad energy market policy is a matter for the right level(s) of government. Policy should deal with overall objectives including efficiency, reliability (and, possibly, the efficient delivery of special assistance to those most in need).

For the NEM, ERIG concludes that the logic set out above points to an important—if not dominant—role for the Commonwealth Government in NEM-wide policy formulation. Ideally, the broad policy objectives set for the NEM should be reflected in the objectives set for the Western Australian and Northern Territory markets as well. This is consistent with the broad national market efficiency imperatives summarised in chapter 3 of this report.
Given that the reality of Australia’s energy sector today is that a number of State Governments have maintained ownership of substantial energy assets, then, at the very least, COAG should have a very important role in overseeing national energy policy.

Market planning, rule making, market operation & regulation

Market planning, rule-making, market operation and regulation are functions properly delegated completely to appropriate independent bodies operating under charters that require them to act to deliver market outcomes consistent with broad government policy objectives on a market wide basis.

These bodies should be formally and functionally independent of governments, have their own independently appointed Boards, and be answerable to the appropriate governments only in terms of delivering the broad objectives set by those governments.

In Australia, a good working example of the appropriate relationship, and appropriate assignment of roles and responsibilities, is that between the Commonwealth Government and the Reserve Bank of Australia (RBA) in relation to inflation:

- the Government (with appropriate advice) sets the desired inflation outcome for Australia as a matter of policy (currently a 2-3% inflation ‘comfort zone’);
- it then contracts with the Governor of the RBA for the latter to conduct monetary policy, operating through RBA Board decisions about the official cash rate, to deliver inflation outcomes consistent with its inflation policy objective; and
- the RBA is formally independent of the Commonwealth Government, and, through its Board, independently conducts monetary policy to promote the agreed inflation objective.

How do governance arrangements for existing organisations line up against this ‘template’ for ‘good governance’? This is considered briefly in what follows. Appendix 6 presents a table summarising current arrangements for:

- ACCC
- AER
- AEMC
- NEMMCO
- Western Australia’s IMO

Ministerial Council on Energy

In its report Reform of Energy Markets to COAG on 11 December 2003, the MCE agreed that further reform should be undertaken to “strengthen the quality, timeliness and national character of governance of the energy markets, to improve the climate for investment”. (MCE 2003, page 4).
The MCE is the energy market policy making body. In its 2003 report to COAG, the MCE recognised that governments should not be engaged in the day-to-day operations of energy markets, and should concentrate on a broad policy making role (MCE 2003, page 7).

But there are potential problems with the structure of the MCE as the electricity market policy maker. There are actual or potential conflicts of interest due to (i) government ownership of energy supply assets in some jurisdictions, (ii) the possibility of a jurisdictional bias in decision making, and (iii) a potential lack of independence between market planners, operators, rule makers and regulators, on the one hand, and governments as policy makers, on the other. Some state and territory Ministers involved with the MCE are also the ‘Shareholder Minister’ in relation to energy assets in their respective states. As ‘Shareholder Ministers’, they are, amongst other things, required to ensure the financial health of that state’s or territory’s energy assets.

At present, the Commonwealth has an equal vote in decision making, along with all states and territories, within the MCE.

Should the Commonwealth have a more prominent role? From a good governance perspective, a fully inter-connected, truly national electricity market would suggest that the answer is ‘yes’. This would support decision making in the interests of a genuinely national market. This applies almost equally to the NEM – about 93% of total Australian electricity supply.

ERIG notes that MCE voting arrangements are not publicly released (is this best-practice, from a transparency perspective?), but understands that legislation-related decisions must be unanimous, and other decisions must be supported by at least seven of the nine members. On the face of it, this seems to give all jurisdictions an effective veto over all legislative decisions of the MCE, a condition that hardly seems conducive to ensuring a national approach to Australia’s energy policy.

How much should the MCE get involved in rule-making and rule reviews? At present—see below—it drives a substantial proportion of the AEMC’s work programme. There is a strong case for the MCE making decisions on broad policy which organisations such as the AEMC should take into account when discharging their own responsibilities. Beyond setting such broad policy objectives, is good governance supported by more detailed intervention by governments?

The MCE regularly reports to COAG on progress (including its own) in implementing key reform initiatives. Does this constitute an independent assessment of performance? Is it outcomes-focussed, rather than being process-focussed?

ERIG believes that there may be a case for a regular independent analysis of Australian energy market reform progress, possibly as a part of an ongoing NRA outcomes monitoring arrangement. This analysis should evaluate implementation of energy market reforms against agreed performance criteria. It could also identify priority areas for further reform.
Planning functions

To the extent that these are covered at present, NEM planning functions are reflected in the Annual National Transmission Statement (ANTS) and the Statement of Opportunities (SOO).

The key questions are:

» Do the current ANTS and SOO adequately cover needed planning information and investment requirements?

» Should a separate planning organisation, at least for the NEM, be established, or could this function be handled by one or more of the existing energy market organisations? From a good governance perspective, there is a case for a separate, independent planning body. Against that, proliferation of energy market organisations, and crucial planning information requirements, might point to allocation of this function to an existing organisation. This latter option, however, is likely to require governance-related reforms to such organisations as well.

Planning matters and planning reform options are dealt with in more detail in chapter 6 below.

Rule-making: the AEMC

The AEMC was established in July 2005 under South Australian legislation, with the other states enacting enabling legislation. It is funded by the states. It is accountable to the South Australian Government and the MCE as a whole.

The AEMC largely reacts to rule-making proposals by others. It cannot initiate rule making proposals based on its own independent analysis of what is in the best interests of the NEM. ERIG is advised that the MCE specifically prevented the AEMC from initiating rule change proposals, other than those of a minor administrative nature. This was to avoid a conflict associated with the AEMC being both the proponent and judge of its own rule change proposals.

Industry can initiate rule change proposals, but a significant proportion of the AEMC’s workload has been rule change proposals initiated by the MCE and the senior officers group reporting to it. Its workload is largely outside the AEMC’s control. The AEMC does have the ability to initiate reviews (subject to resourcing constraints) into the operation and effectiveness of the rules, or any matter relating to the rules, after notifying the Minister of its intentions. After completing a review a copy of the report must be provided to the MCE.

In principle, ERIG considers that it would be beneficial for the AEMC to have a greater degree of discretion to process rule changes and to review proposals put before it that it considers have the highest potential benefit for the market, subject to a transparent, accountable process. Aggregation of related rule change proposals before processing might also be helpful.

ERIG notes that, in its 26 October 2006 Communiqué, the MCE indicated its agreement to include amendments to the NEL to assist the AEMC to manage its workload and consolidate like rule change applications. These amendments form part of a suite of other legislative changes which are expected to be introduced into the SA Parliament in May 2007 with the intent that they would enter into force from 1 July 2007.
The Chairman of the AEMC is the only full time commissioner. Given the demands on the AEMC, there may be merit in making all commissioner positions full time.

On AEMC funding, ERIG believes current arrangements are unsatisfactory:

- the States agreed to jointly fund the AEMC. The Commonwealth Government agreed to fund the AER;
- the funding process for the AEMC requires the unanimous agreement of all member states for future funding agreements or budget revisions;
- to the extent that differences exist over certain matters, ERIG understands that states may delay or refuse to ratify future funding arrangements;
- AEMC funding is not publicly released: it is not transparent;
- it is not possible for outsiders to assess whether or not AEMC funding is adequate to allow it efficiently to discharge its responsibilities; and
- the current resource needs of the AEMC are the subject of an independent efficiency review by a consultant on behalf of MCE officials.

ERIG believes that these funding arrangements are potentially detrimental to the efficient operation of the market and to the independence of the AEMC. ERIG concludes good governance warrants reforms to AEMC funding arrangements.

A key element of reform should be transparent funding arrangements and ensuring the independence of the AEMC.

Given its NEM-wide responsibilities, ERIG considers there is a good case for Commonwealth funding of the AEMC, preferably entirely, or at least in part.

**Rule-making: electricity market rules**

Electricity market rules continue to include a large set of derogations for each state which, along with other separate legislation and regulatory instruments, make each state’s market unique. This situation hampers efficient national competition and the emergence of a truly national market. Differing state schemes cut across AEMC efforts to develop efficient national rules.

The amended Australian Energy Market Agreement, dated 2 June 2006, between the Commonwealth and the States and Territories, sets out the basis for aligning distribution and retail regulation and progressively removing some state regulation.

But different state schemes continue to be announced in areas such as greenhouse gas abatement policy, customer protection, and retail settlements.

ERIG considers that the states should:

- commit to align, on a NEM-wide basis (and, preferably, an Australia-wide basis), as many legislative, regulatory and rule-based provisions as possible, in order to support a truly national market; and
- provide for an annual independent stock-take, as part of any NRA outcomes monitoring arrangement, of progress towards national consistency in these areas.
Electricity market operation: NEMMCO and IMO

NEMMCO

NEMMCO provides the electricity market operation function for electricity markets in the NEM and the IMO provides the market operation function for the WEM. (Aspects of gas market operation are the responsibility of three separate entities - VENCorp, GMC and REMCo.)

NEMMCO was established in May 1996 to implement, administer and operate the wholesale NEM, manage the security of the power system and continually improve the efficiency of the NEM. It is a body whose members are the governments of the Australian Capital Territory, New South Wales, Queensland, South Australia, Tasmania and Victoria. These governments are parties to a Members Agreement. This Agreement is not a public document.

NEMMCO’s functions are prescribed in the NEL and are:

» to operate and administer, in accordance with this Law and the Rules, the wholesale exchange;

» to promote the development and improve the effectiveness of the operation and administration of the wholesale exchange;

» to register persons as Registered participants in accordance with this Law and the Rules or otherwise in accordance with the Rules;

» to exempt certain persons from being registered as Registered participants;

» to maintain and improve power system security;

» to undertake the coordination of the planning of augmentations to the national electricity system; and

» any other functions conferred on it under this Law or the Rules.

At present, the majority of the Board of NEMMCO consists of members each of whom have been nominated by an individual (state/territory) jurisdiction. The Chair is appointed jointly by the participating jurisdictions. Board membership by the Australian Government is specifically excluded.

The NEMMCO Board has the power to appoint up to two individual members if they consider it desirable to add to the Board’s experience. ERIG has been advised the Board has used this right to appoint NEMMCO’s chief executive to the Board and one other member.

The role of the board, among other things, is to establish NEMMCO’s general operating policies and the statement of corporate intent (SCI). The finalisation of the SCI is subject to consultation with members.

It is doubtful that board membership influences decision making by NEMMCO in performing its closely prescribed functions. ERIG notes, however, that NEMMCO possesses discretion
in a number of areas including the way it manages constraints, negative settlements and the dispatch of the wholesale market. Such functions require a high level of transparency if market participants are to have confidence in the organisation. ERIG is aware of views from a variety of market participants that NEMMCO could do more to advance the interests of the NEM as a whole relative to jurisdictions within the NEM.

To provide investor confidence and give NEMMCO stronger incentives to provide an impartial and efficient service delivery, ERIG sees value in reforming the governance of NEMMCO. ERIG sought advice from Firecone on NEMMCO’s governance. In its December 2006 report to ERIG, “Planning and Governance Arrangements for the National Transmission Grid”, Firecone advised that:

“The public policy objectives of Australian governments are principally achieved through the appointment of the AEMC, to determine the market Rules, and of the AER to enforce them and to conduct the regulation of natural monopolies. The current governance arrangements for NEMMCO entail a high degree of government control, both in relation to what is needed to meet public policy objectives and in comparison with other markets.” (Firecone, 2006, page v).

As noted by Firecone:

“Governments, market participants and major consumers all have a legitimate concern with ensuring effective discharge of NEMMCO functions”. (Firecone, 2006, page v).

ERIG considers that having industry, and potentially customers, involved in the appointment of NEMMCO’s Board could improve its focus on operating the market efficiently and would certainly directly address perceptions of jurisdictional bias. The NEMMCO Board appointment process should seek to ensure that the board is independent of individual jurisdictional or sectional interests and contains the appropriate range of skills.

Firecone recommended that all Directors should be jointly appointed by a government and industry panel. The appointing panel would consist of two industry representatives, two government representatives and the Governments would also appoint a Chair, with a casting vote. The Government appointments would be made by the MCE and industry appointees would be selected by voting, with one vote for each registered market participant.

Firecone notes that this approach

“leaves government with significant control over NEMMCO’s overall performance.” (Firecone, 2006, page vi).

This has some justification as the jurisdictions jointly own NEMMCO and bear risks from any under-performance, and the inclusion of industry in the Board appointment process would add value to the selection process and to the quality and independence of the Board selected.

Whilst a significant ongoing role for Governments in the appointment of the NEMMCO Board may be appropriate, NEMMCO’s market operations function should have a greater level of industry control. Firecone suggested that this could be achieved by establishing a “Market
Operations Panel’ which would oversee the market operation services. This proposal is further discussed in chapter 7 below.

These changes to NEMMCO’s governance are appropriate at this point in the development of the market to drive performance into the future. They are justified on their own merits but also provide greater scope for future development to implement ERIG’s proposals:

» to create a national transmission planning function (see chapter 6);

» for common settlement of the physical spot market and financial market to avoid credit duplication (see chapter 7); and

» to consider the merits of establishing a single national market operator for both gas and electricity (see below).

In the case of its functions to provide information, including planning analysis to the market, there should be benefits both to having a greater service culture in meeting the market’s needs and through a greater degree of independence which should provide greater impartiality in decision making and analysis.

A number of respondents commented favourably on the potential of a new national planning body being within NEMMCO, subject to suitable governance reforms. This matter is further addressed in the Transmission chapter.

The implementation of the proposed ‘Market Operations Panel’ could provide an appropriate body to manage further financial services, and a second ‘Gas Market Operations Panel’ would be a potential way to integrate national gas market operations into a reformed NEMMCO at an appropriate point of development.

Concerns about NEMMCO’s current governance and hence its ability to move in these areas have been raised by many in the financial markets area and by the Gas Market Leaders’ Group. The proposed reforms to NEMMCO’s governance would have a significant impact on the assessment of NEMMCO’s ability to take on further roles proposed in the planning and broader energy market operation areas.

The Western Australian IMO

The IMO operating in Western Australia has a 3 person board appointed by the WA Minister.

ERIG is advised that the IMO has responsibility for:

» market operation (NEMMCO’s role in the NEM);

» development of the market rules (AEMC’s role in the NEM). (There is a market advisory committee which advises the IMO on the rules. The IMO has the power to appoint and remove members of the committee);

» monitor compliance with the rules;

» initiate enforcement action for breaches (AER’s role in the NEM); and

» operate the reserve capacity mechanism, with the regulator, ERA, approving the maximum and minimum prices for the reserve (capacity largely driven by the market in the NEM).
ERIG acknowledges that:

» the WEM is a smaller market than the NEM; and

» it has only recently commenced operations, and it is too soon to assess how well it is operating.

However, these multiple IMO responsibilities suggest conflicts of interest when assessed against the good governance template outlined above. The Western Australian government should consider whether there would be advantages to appropriately disaggregating those functions and having them undertaken by the relevant national body; ie, the AER, the AEMC or the proposed National Energy Market Operator.

The ‘light on the hill’: a national energy market operator?

GMLG has recently developed a Gas Industry Development Plan recommending a single gas market operator, bringing together the operations of the three separate entities, VENCorp, GMC and REMCo.

On efficiency grounds, this recommendation seems eminently sensible and as noted in chapter 7, ERIG observed widespread support for the recommendations of the GMLG.

However ERIG wonders whether Australia should go further, and introduce a single national energy market operator?

ERIG is not alone in considering this issue. This is also a critical issue currently being considered by the MCE.

In the time available, ERIG has not done as much analysis on this proposal as others have.

VENCorp noted that “the most efficient and effective solution for a national energy market is a national energy market operator. Having two organisations, NEMMCO and the GMO, performing the same function, that of operating their respective markets, would be a sub-optimal outcome for the energy market and would not be consistent with the creation of the new regulatory structure” (VENCorp response to ERIG Discussion Paper, December 2006, page 2).

VENCorp considered the benefits of establishing a national energy market operator would include:

» more efficient outcomes for the energy market arising from information sharing leading to an improved understanding of market operations and interactions between the gas and electricity sectors;

» improved emergency management coordination;

» economies of scale arising from common information technology systems for gas and electricity (for market operation, system monitoring and information gathering);

» the provision of a single interface for energy market participants reducing red tape and duplication of interactions, thereby lowering costs;

» administrative cost savings in corporate support structures; and
a more substantive organisation able to attract and retain a core mass of appropriate expertise.

The GMLG also considered the option of a national energy market operator. (See National Gas Market Development Plan, Gas Market Leaders Group report to MCE, June 2006, page 48)

A key impediment to this group reaching a recommendation for one single market operator was the current governance arrangements of NEMMCO. The GMLG was of the view that a merged gas market operator should be a body, responsive to, and reflective of, the unique characteristics of the gas industry and of the needs and interests of gas market participants. The GMLG concluded that the current jurisdictional-based structure of NEMMCO did not meet these objectives.

Further the GMLG considered the widespread support amongst gas market participants for the Group’s recommendation to create a single gas market operator was a significant and important reform for the gas industry and its establishment would facilitate convergence of gas and electricity markets over the longer term.

ERIG supports both of these perspectives.

Whilst ERIG has not had an opportunity to undertake a detailed cost benefit analysis (and it would be important to do so), ERIG believes that there are significant synergies to be captured by the creation of a single market operator.

This initiative is an important reform which is consistent with supporting a national and efficient Australian energy market and recognises the growing convergence of electricity and gas. It is also important for ensuring there is a level playing field between gas and electricity. A single energy market operator would result in further rationalisation of market institutions, hence reducing the costs of operating in the market.

ERIG considers there are two implementation options available:

» there may be a case for immediately establishing a single national energy market operator rather than accepting a transitional phase of setting up a separate gas market operator. If implemented by COAG, the revised governance arrangements for NEMMCO (see above) are broadly consistent with the board appointment arrangements proposed by the GMLG for the gas market operator; or

» alternatively, the objective of establishing a national energy market operator could be endorsed as a longer-term objective.

On balance ERIG considers that two steps are necessary. Implementing the reforms of the GMLG is an important step and reforming NEMMCO’s governance arrangements is another. This approach does not put at risk the significant momentum for reform in the gas industry and allows time to implement changes to NEMMCO’s governance.

ERIG therefore considers that COAG should endorse the establishment of a national energy market operator as a longer term governance objective for the energy market.

On the assumption that the cost-benefit analysis is favourable, decisions to progress a gas market operator as an intermediate step should sensibly take account of the longer term objective for a national energy market operator.
Market regulation: AER and ACCC

For energy markets, the regulatory function seems to be relatively settled and largely appropriate within Australia. The AER is now, or will become, the Australia-wide regulator of energy markets, both electricity and gas (with the exception of WA for gas and electricity and NT for electricity). In WA the Economic Regulatory Authority is the entity responsible for energy regulation and in the NT the responsible entity is the Utilities Commission, an independent unit within the NT Treasury. The ACCC has Australia-wide responsibility for TPA matters. Both are funded by the Commonwealth Government.

Subject to some TPA ambiguities in relation to government-owned businesses (see ‘regulatory adequacy’ sub-section below), the AER and ACCC seem to have appropriate governance arrangements in place.

The justification for a local regulator with respect to electricity in WA and the NT rests on the argument that these are different markets. It is not apparent to ERIG that a similar argument can be effectively mounted for gas in WA. At the wholesale market level, the AER enforces the market rules in the NEM and there is no reason why it could not do the same in the WEM.

Government involvement in day-to-day business operations

ERIG notes that Ministers can play an active role in the day-to-day operation of their public corporations through, for example, the appointment or termination of board members and executives and their statutory power to issue directions to their corporations.

In some cases, ERIG believes that these activities may be inconsistent with recommendations for good governance of government businesses set out in a review by Richard Humphrey. One of the recommendations in that report stated that:

“… the governance principles embodied in the listing rules for public companies and the Corporations Law should apply to government business enterprises.” (Humphrey 1997, page 7).

Under these principles, directors should act in the best interests of the company.

ERIG appreciates that there are important differences between State Owned Corporations (SOCs) and private companies incorporated under the Corporations Act 2001 (see the ‘carve-outs’ reviewed under the ‘regulatory inadequacies’ sub-section below). These may indeed allow governments greater discretion in decision-making than would apply to private companies.

Good governance requires that these ‘carve-outs’ should be eliminated.
Government participation in the market more generally

ERIG considers that, ideally, governments, and organisations charged with planning, rule making, market operation and regulation, should not be market participants, except in the following cases:

» Governments must, of course, participate in the electricity market on the demand side – as customers. If this is their only market participation role, they have a vested interest in promoting competitive and efficient market outcomes. In contrast, where they participate on the supply side as business owners, they face conflicting incentives, including pressures to charge higher prices and limit competition for profit-raising reasons.

» Organisations charged with planning, rule making, market operation and regulation should not be making profits from supplying electricity. That is a conflict of interest. But they must also ‘participate’ in the market in a variety of ways, including: monitoring market outcomes and trends; forecasting market developments; making sure that the physical market balances in real time, and that the rules make it work as efficiently as possible; regulating participants’ behaviour and merger activity; and obtaining the market information needed to discharge all of these responsibilities effectively.

Good governance is an integrated package

ERIG believes that dealing with all of the governance principles noted above is needed to eliminate or minimise risks of poor market outcomes. ‘Cherry picking’ will not deliver the best results.

For Australian electricity markets:

» privatisation is a relatively clean solution to conflicts of interest in those jurisdictions where governments currently are asset owners, policy makers, rule makers or initiators, and regulators;

» bolstering competitive neutrality is the (imperfect) alternative;

» ensuring genuine independence and accountability for organisations charged with planning, operating and regulating electricity markets is important. The Reserve Bank of Australia model may be a good template;

» adequate resourcing of these independent bodies, (including possibly through Commonwealth Government financial support in the case of the AEMC), is also crucial. Without it, they cannot operate effectively; and

» planning must be both market-wide and cover all supply elements, including co-ordinating efficiently-located generation and transmission. This matter is taken up in more detail in chapter 6 below.
ERIG findings on governance

Notwithstanding reforms fostering better energy market governance in the 1990s and into the 21st century, ERIG concludes that additional governance refinements would support the emergence of a truly national and efficient energy market.

Privatisation of remaining government-owned electricity assets would eliminate potential conflicts of interest and facilitate arrangements removing intra-market jurisdictional biases.

Sharpening the separation between the role of the MCE as the peak policy-making body, and the bodies responsible for planning, operating, rule-making and regulation of Australia’s energy markets, would improve governance, including by ensuring the independence of market operators from governments. Increasing the influence of the Commonwealth Government within the MCE or at the very least an important role for COAG would help as well.

Planning needs some ‘beefing-up’ beyond the SOO/ANTS processes. This is dealt with in more detail in chapter 6.

The AEMC is most in need of substantial governance reforms. It needs to be adequately and transparently funded, preferably by the Commonwealth Government, and to have more control over its own work programme, subject to being required to develop rules that enhance market efficiency. It needs a full time Board.

Australia’s electricity market rules are not uniformly applied across Australia because of numerous state derogations. This is inconsistent with a national, efficient, energy market. Uniform rule application should be applied as soon as possible, with annual independent reviews of progress.

NEMMCO’s governance could be improved by providing for more independence in relation to Board appointments, and industry involvement in those appointments. The introduction of a ‘Market Operations Panel’ representing the industry in the management of the market operations functions of NEMMCO would further improve its service culture. These reforms are crucial pre-requisites for other reforms potentially involving NEMMCO, including in relation to planning; more efficient financial market settlement arrangements; and the feasibility of a single energy market operator.

The IMO’s role in the Western Australian Energy Market (WEM) combines market operation, market rule-making, monitoring rule compliance, enforcement action for breaches, and operating the market reserve capacity mechanism. While the WEM is a relatively small market compared with the NEM, and has only recently commenced operating, ERIG considers this bundling of disparate functions within one body raises numerous conflict of interest concerns. There could be advantages to appropriately disaggregating those functions and having them undertaken by the relevant national body; ie, the AER, the AEMC or the proposed National Energy Market Operator.

A national energy market operator in place of separate operators for gas and electricity has efficiency advantages and should be adopted as a longer term governance objective.

The roles of the AER and ACCC are relatively well settled and their governance seems relatively well sorted. The only refinements relate to extending the responsibilities of the AER to WA and the Northern Territory.

Governments should not become involved in the day-to-day running of energy supply businesses, even if they own them. At present, there is evidence that they do. The fact that they can, highlights the need for governance improvements for government-owned businesses to bring them into line with their private sector counterparts.

As players in energy markets, governments should align their interests with those of energy customers, and avoid the conflicts inevitable when they are also suppliers.
Market Structure Recommendations: governance

The following recommendations are designed to improve the efficiency of Australia’s energy markets by improving governance.

2. Improving market governance

2.1 Ministerial Council on Energy

To support its own 2003 agreement to strengthen the national character of energy market governance, and to sharpen its own broad policy-making function, ERIG recommends that the MCE’s role should be reviewed by COAG. The focus of the review should be (i) to ensure the MCE concentrates solely on broad policy-making for the energy market; (ii) to eliminate more detailed intervention by the MCE and its officials in detailed rule-making; and (iii) to evaluate the merits of an increased role in policy oversight by the Commonwealth Government or COAG to support a more ‘national character of governance of the energy markets’.

This recommendation applies to COAG.

2.2 Planning

ERIG recommends that planning functions be strengthened beyond those embodied in the SOO/ANTS processes, in order to enhance system-wide energy investment efficiency (covering both generation and energy transmission/distribution) on a truly national market basis.

This general recommendation applies to COAG.

More detailed recommendations on planning are presented in chapter 6 below.

2.3 AEMC

Of all the governance recommendations made by ERIG, those relating to the AEMC are amongst the most urgent. ERIG recommends that the AEMC’s funding, autonomy, accountability and board structure be improved as a matter of urgency.

More specifically, in the interests of a national market approach, ERIG recommends that: (i) the AEMC’s funding be made transparent and adequate for its role, and, preferably, be the responsibility of the Commonwealth Government; (ii) the AEMC have more control over its own work programme, subject only to being fully accountable to governments for its performance in delivering against government policy objectives for Australia’s energy markets (eg, efficiency and reliability); and (iii) AEMC’s resources should allow it independently to appoint a full-time Board, comprising members with appropriate experience and, consistent with good governance, free from perceptions of (actual or perceived) conflicts of interest.

These recommendations apply to COAG.
2.4 Electricity market rules and other regulation

ERIG recommends that operating rules and other state-specific legislation and regulatory instruments should be harmonised across Australia’s energy markets to support a more national market framework. As part of this process, the current numerous state derogations from existing rules, and differences in retail regulation and other state regulations, should be greatly reduced.

ERIG also recommends that there be an independent review of the implementation of energy market reform and, as part of this, progress towards national consistency, as part of any NRA outcomes monitoring arrangements.

These recommendations apply to COAG and all states and territories.

2.5 NEMMCO

ERIG recommends that NEMMCO’s governance be reformed for it to operate more autonomously.

In particular, ERIG recommends that industry representatives be involved in the appointment of NEMMCO’s Board. The NEMMCO Board appointment process should seek to ensure that the board is independent of individual jurisdictional or sectional interests and contains the appropriate range of skills.

The reform of NEMMCO’s governance would contribute to NEM-wide efficiency and is justified in its own right. This recommendation also has important implications for other recommendations presented in chapters 6 and 7 below, as well as a possible national energy market operator function. (see recommendation 2.7 below)

These recommendations apply to COAG, and all NEM States and the ACT.

2.6 The Western Australian IMO

While it is too soon to assess the performance of the Western Australian Electricity Market (the WEM), ERIG is concerned about the multiplicity of functions allocated to the IMO. These seem to involve significant potential governance problems (mainly functional conflicts of interest).

ERIG recommends a review by the Western Australian Government of these governance issues in order to identify whether actual problems exist, and to deal with them if they do.

In this context ERIG recommends that Western Australia investigate the merits, at least over time, of using the AER, the AEMC and NEMMCO as the regulator, rule-maker and operator, respectively, of the WEM. (see also recommendations 2.3 above, and 2.7 and 5.6 below)

This recommendation applies to Western Australia.
2.7 A national energy market operator

From a national efficiency perspective, there is much to be said for moving as quickly as possible to a national energy market operator in place of the current electricity market operators (several), and gas market operators (several).

Subject to acceptance of recommendations concerning NEMMCO’s governance presented in this chapter and in chapters 6 and 7, ERIG recommends COAG agree to establish a single energy market operator as a longer term governance improvement for the Australian energy market, rather than having separate gas and electricity market operators. ERIG recommends COAG develop a detailed program timetabling the steps to the establishment of a single energy market operator. (see also recommendation 5.11)

This recommendation applies to COAG.

2.8 AER and ACCC

For Australia’s energy markets, the regulatory function seems to be relatively well settled (subject to resolution of the issues raised under the ‘regulatory adequacy’ recommendations set out below).

From a national market/efficiency perspective, the main issue is the sub-national coverage of the AER. ERIG recommends that the AER should have responsibility for energy market regulation across Australia.

This recommendation applies to Western Australia and the Northern Territory.
Regulatory inadequacies: Australian energy markets

Competition reforms in the 1990s included structural separation of competitive electricity market elements from natural monopoly networks to promote competition in electricity generation and retailing.

Given subsequent market developments, are competitive outcomes being maintained or have they been significantly undermined? ERIG has found very limited evidence of problems.

Background

The Hilmer report (1993) established a broad set of principles and policies underpinning the implementation of competition and related reforms by Australian governments during the 1990s.

In the electricity sector, these principles implied the separation of the natural monopoly networks (transmission and distribution) from the competitive segments (generation and retail) and open access to the grid. This separation was intended to establish generation and retail competition. In the gas sector, competition was enhanced through the introduction of arrangements to enable third party access to the gas pipelines.

Governments in each state have separated the competitive generation sector from regulated network businesses. They have also separated transmission from distribution, although they have only ring-fenced the competitive retail business from regulated distribution services.

In addition, generation and distribution/retail segments were disaggregated into a number of businesses to foster more competitive markets.

In jurisdictions with private ownership of energy assets, retail and distribution businesses have been separated as a result of commercial decisions. In the same jurisdictions, other business segments have been consolidated. This has included a trend mainly towards partial combinations of retail and generation assets.

Is any tendency to reintegrate parts of the Australian electricity industry a threat to competitive outcomes? This sub-section of chapter 5 considers this question under several headings:

» vertical integration;

» horizontal aggregation;

» the adequacy of the TPA;

» the case for special ownership rules in the electricity sector; and

» effectiveness of regulation of asset management arrangements.
Vertical integration

Vertical integration involves complete or partial mergers between suppliers in different markets where those markets are part of a single chain of production. Some have asserted that vertical integration is itself a threat to competitive market outcomes.

Vertical integration in electricity: businesses in competitive markets

In the electricity industry, partial or complete integration between competitive sectors involves mergers between generation and retailing activities to form so-called 'gentailers'.

Commercial incentives for this type of vertical integration include:

» a physical hedging mechanism against pool market price risk;

» providing collateral (generation assets) for financing purposes and to meet prudential requirements of the national electricity market;

» the creation of some economies of scale and scope; and

» a competitive response to vertical integration by competitors.

It has also been suggested that vertical integration could be exacerbated by financial market imperfections. ERIG notes that, if this is the case, it does not suggest vertical integration is a problem per se. Rather, it suggests barriers to entry into financial markets are a problem, and the correct policy response is to deal with these. These matters are dealt with in chapter 7.

ERIG notes the regulators’ views on vertical integration in competitive markets:

“While the ACCC will assess any future integration on a case by case basis, the majority of future proposals that only involve generator-retailer integration are also unlikely to involve a substantial lessening of competition” (AER/ACCC sub. no. 35, page 18).

ERIG considers that vertical integration can only be a problem when there is insufficient competition (and market power exists) horizontally in at least one of the markets in which the merged entity operates.

The evidence from overseas supports this view:

» evidence from the PJM, New England and California markets in the US, as well as the UK market, suggests vertical integration has not had an adverse effect on electricity prices. But in these cases, there appears to have been adequate horizontal disaggregation and competition; and

» in the New Zealand market, vertical integration has led to the concentration of the market into five integrated entities. The nodal pricing design of the New Zealand market, together with vertical integration, has given rise to regionally dominant ‘gentailers’ (i.e. resulting in major horizontal aggregation within regions). Here, the problem appears to be horizontal aggregation within regions, with which vertical integration is associated.

ERIG concludes that, within contestable markets, vertical integration is not likely to be a problem per se. However vertical integration can be associated with market power
problems where at least one of the merging entities possesses market power in the market in which it operates.

This suggests the need to focus on excessive horizontal aggregation as the primary source of market power problems. This is dealt with later in this chapter.

**Vertical integration in gas: businesses in competitive markets**

Historically, the lack of a meshed gas network in Australia allowed for little direct competition between gas suppliers. The absence of such networks might enable the integrated gas supply/retail firm to deny market access to competing retailers. Some argue that the gas market feature of long term bilateral contracts delivers minimal transparency, increases entry barriers to competing retailers, and impedes the development of a functional financial market.

Now, however, competition is increasing between Bass Strait, Cooper and Ottway sources; from coal seam methane (CSM); and potentially from other sources such as Papua and New Guinea and the Timor Sea. At the very least, these raise threats of contestability which itself can be a significant source of competition.

The gas business model has evolved along a different path from electricity supply. Typically, in the past large long term contracts have been required to underwrite the development of the gas resource and associated pipeline investment. These contracts are negotiated between large informed buyers and sellers. They only occur where their terms are satisfactory to both parties.

This model is now changing anyway. As noted above, the available sources of gas supply are increasing. The development of a more highly meshed gas network is encouraging greater levels of competition between competing gas sources as well.

This positive trend might be undermined by high levels of vertical integration in a sector which is already highly concentrated at the horizontal level. But, if so, again, this will be because of excessive horizontal aggregation. This is dealt with later in this chapter.

**Vertical integration between electricity generation and transmission**

At its meeting on 10 February 2006, COAG decided legislatively to enforce the separation of generation and transmission. Separation has been a universal approach to electricity reform adopted by governments around the world in order to facilitate generation competition.

Electricity transmission assets are, by definition, natural monopoly assets. Owners of transmission assets also owning generation assets could have an incentive and ability to restrict access or discriminate against competitors.

ERIG notes that the ACCC has expressed concern about the adequacy of the TPA to protect against the likely anti-competitive outcomes to which these vertical mergers may give rise. As noted by the ACCC/AER, this is because:

> “When the owner of essential infrastructure also participates in a contestable market it typically has the ability and economic incentive to restrict the level of competition in the contestable market in ways that are difficult to prevent or monitor” (ACCC/AER submission no. 35, page 16).
This can be effected in a variety of subtle ways, including, for example, through access arrangements, benefits provided to affiliated companies, the sharing of commercially sensitive information and through more or less beneficial connection agreements or line rating decisions.

ERIG agrees that such mergers are neither desirable nor likely to be effectively regulated through section 50 of the TPA, and that specific ownership restrictions in this case are a low risk alternative strategy.

In the interests of investment certainty, ERIG believes governments should promulgate specific cross-ownership rules in this area as soon as possible.

In relation to such rules—which have not been promulgated at the time this report has been finalised—ERIG also notes the following important questions should be considered:

» how will such rules apply to government-owned electricity assets? If they are applicable to government-owned utilities, but not to the ultimate (government) owners of such utilities, does this give rise to potential problems?

» do similar competition concerns arise when gas transmission pipelines and electricity generation assets are under common ownership?

» more generally, should special cross-ownership rules be applied consistently across competing energy sources? If they are not, could distortions to investment decisions be introduced by such rules?

Vertical integration between electricity distribution and retail

In principle, vertical integration between distribution and retail businesses raises similar competition issues to vertical integration between transmission and generation businesses. Distribution networks are ‘natural monopolies’.

Integration between distribution and retail may raise the following concerns:

» the capacity to ‘smuggle’ retail costs into the regulated business;

» the provision of higher levels of service by the integrated entity to its own retail customers; and

» delays and higher costs imposed on competing retailers through the negotiation of use of service agreements.

However, a number of parties, (including the regulator) suggested to ERIG that distribution and retail integration does not raise the same degree of competition concerns as integration of generation and transmission.

At its meeting on 19 August 1994, COAG decided not to separate retail from distribution, but to allow such activities to operate through ‘stapled’ arrangements in both markets, with separation enforced through ring-fencing of the integrated businesses.

The access code was developed having regard to this arrangement. ERIG understands, however, that ring-fencing is not maintained universally and some exemptions have been granted by the regulator.
The National Generators Forum (NGF) suggested that the use of ring-fencing is suboptimal as it requires regulatory oversight which is inherently inferior to a structural solution and is subject to gaming. As the monopoly elements are potential channels to market power, an owner with an interest in both asset classes could have an incentive to adversely affect a competitor. NGF argued that if ring-fencing is effective why not have full separation?

ERIG agrees with the logic behind these arguments – in principle.

However, for distributor/retailer mergers, no evidence was presented to ERIG to suggest that the current regulatory arrangements themselves have impeded competition in practice. In relation to the gas sector, Energy Australia noted that although the finalisation of access arrangements is resource-intensive, they are becoming more effective with time.

In ERIG’s opinion, there is also a much more important practical reality. This is the evolution of the market in this area. Where distribution and retail assets are owned by the private sector, an overwhelming trend has been the separation of the formerly stapled distribution and retail businesses, and specialisation in either regulated or competitive entities.

The commercial drivers behind this include:

- unlike the case with generator/retailer mergers, there are no ‘natural hedge’ benefits;
- markedly different costs of capital for regulated and competitive assets;
- the different business models required of the distribution and retail sectors;
- the presence of strong retail competition;
- an effective regulatory regime; and
- the capacity of specialist network firms to leverage network businesses as a pure infrastructure investment.

ERIG agrees that the in-principle concern about mergers between entities with market power suggests that full structural separation is a logical arrangement from an efficiency and competition perspective. But should this be implemented via proscription as a policy rule?

ERIG does not consider that a sufficient case has been made for government intervention to enforce such an outcome at this time. The market is doing the job itself. It is moving to separate retail and distribution activities and there are now no integrated retailer/distributors in commercial hands. The only combined distributor/retail businesses are those in government ownership.

This suggests an alternative, market-consistent, policy solution: the privatisation of such assets.

Where governments take action to restructure or privatise their energy retail and distribution activities they should provide for separation as part of the privatisation process. The Queensland Government is a good example of this model. It has decided to sell its retail electricity businesses as stand-alone operations, rather than being stapled with the distribution assets.
Horizontal aggregation

Overview

Whether or not horizontal aggregation has proceeded to the point where there has been a significant lessening of competition, in practice, is a matter for the regulator to determine.

The regulator does not consider that there is excessive horizontal aggregation at present, (or that the TPA is inadequate in relation to dealing with mergers within contestable markets – see below).

“The ACCC has also considered a number of horizontal generation mergers under section 50 of the TPA. To date, the ACCC considers that the TPA has generally been effective in the consideration of competition issues associated with these horizontal electricity generation mergers…. The ACCC/AER notes, however, that the findings of French J have not been tested in the context of a significant generation merger. While the ACCC has recognised French J’s decision in subsequent merger proposals considered since the AGL – Loy Yang case, the ACCC has stated that, in its opinion, a different market was relevant” (AER/ACCC sub. no. 35 in response to the Issues Paper, page 20).

Horizontal aggregation leading to businesses being able to exert significant market power can be a competition problem. Even with high concentration within a market, much will depend on contestability – that is, the capacity of new businesses to enter the market.

Large energy consumers and small consumer representatives asserted that there are increasing levels of ownership concentration in the electricity and natural gas sectors and that this is a problem for competitive market outcomes.

ERIG considered these claims in each key segment of the energy market.

Generator aggregation

Whether a particular merger between two generator businesses gives rise to systemic market power that results in a substantial lessening of competition will depend on the particular circumstances of each case.

A distinction must be made between price spikes needed as the signalling mechanism in an energy only market and the exercise of market power. The latter is a competition problem. The former is not.

ERIG concludes that the ability of generators to raise prices from time to time (representing, in total, a small percentage of total time) does not, by itself, indicate a generator has market power. Energy only markets use price as the signalling device to induce new investment.

Sustained market power requires generators to sustain average pool prices over long periods above their economically efficient level.

ERIG has received no evidence of sustained market power problems across the NEM as a whole.

However, there is evidence of market power problems within the NEM, and in particular within NSW. This evidence has been reviewed in chapter 4 above. Dealing with this problem
means dealing with government ownership of electricity assets within NSW, either by privatisation of by shoring-up competitive neutrality safeguards.

**Retail aggregation**

Electricity and gas retail markets in some jurisdictions within Australia can be very competitive. The evidence for this is the number of entries and exits from the sector, the extension of retail activities by many businesses across more than one jurisdiction, and the proportion of customers changing retail contracts. Table 8 below shows the cumulative number and proportion of customer transfers in Victoria, NSW, Queensland and SA.

In order to show the number of customers actually changing retailers, ERIG notes that the ‘churn’ data should be disaggregated between customers moving to market contracts with the same retailer and those customers changing retailers.

<table>
<thead>
<tr>
<th>State</th>
<th>Cumulative number of small customer transfers to October 2006</th>
<th>Transfers as a percentage of total customers</th>
</tr>
</thead>
<tbody>
<tr>
<td>Victoria</td>
<td>1,618,259</td>
<td>69%</td>
</tr>
<tr>
<td>NSW</td>
<td>793,522</td>
<td>25%</td>
</tr>
<tr>
<td>SA</td>
<td>402,209</td>
<td>53%</td>
</tr>
<tr>
<td>Queensland</td>
<td>5,619</td>
<td>Less than 1%</td>
</tr>
</tbody>
</table>

Source: NEMMCO 2006

Clearly, gross retail customer ‘churn’ rates are much higher in Victoria and South Australia than in NSW and Queensland.

ERIG finds that the retail segment of the energy industry is generally highly contestable in jurisdictions where private ownership is a feature of the market. ERIG concludes that mergers between retailers that have been allowed to date do not raise competition concerns in such markets at the present time.

**Network aggregation: transmission and distribution**

Transmission and distribution functions within electricity and gas markets are ‘natural monopolies’. These assets are regulated as a result of this reality.

Mergers within these energy networks are unlikely to raise competition concerns provided that these assets are effectively regulated.

Integration may unlock efficiencies through common operation of network assets. ETNOF cited increased reliability and efficiency gains from greater integration of network activities through economies of scale and scope. In principle, this argument should also hold true for horizontal mergers of gas transmission pipelines, again, provided they are subject to effective regulation.

Submissions to ERIG generally supported this view. In its submission to the ERIG Issues Paper, Freehills noted that:

“*in theory the network businesses could all aggregate into one without any effect on competition*” (Freehills sub. no. 18, page 6).
However, ERIG notes that significant potential problem of information asymmetries that would need to be assessed in evaluating whether regulation can be fully effective in such cases.

ERIG is of the view that horizontal mergers of network assets, if effectively regulated, may produce efficiency gains while not posing a threat to competitive outcomes.

But there is a big ‘if’ that needs to be addressed.

How effective is regulation in delivering efficient output and price outcomes? This is dealt with in chapter 6.

Is the Trade Practices Act effective?

The TPA provides the legislative safeguard for competition and fair trading laws in Australia.

Part IIIA of the TPA is intended to ensure that there is effective access to energy network assets. Part IV of the TPA prevents participants from acting in an anti-competitive manner. Of particular significance to this report, section 50 of the TPA prevents merger and acquisition activity that would result in a substantial lessening of competition.

Some market participants and consumer groups have expressed concern over the perceived anti-competitive outcomes of recent energy market merger activity. They also assert that the competition provisions contained in the TPA are inadequate in regulating mergers that may be anti-competitive.

Recent merger activity (and de-merger activity, in the case of distribution/retail entities), has been driven by commercial factors. ERIG has received no evidence that permitted mergers have caused a substantial lessening of competition, or that the TPA has been an inadequate safeguard protecting competitive market outcomes.

In relation to horizontal mergers between generators, the Productivity Commission view is as follows:

“Put simply, there does not appear to be anything inherent in mergers between generators that section 50 would not be able to handle. The prospect that some market power currently exists does not preclude a useful role for section 50 in preventing mergers that would exacerbate this situation” (Productivity Commission 2005, page 190).

In its submission to ERIG, the ACCC/AER agreed in relation to horizontal mergers in the retail and generation sectors. The ACCC has considered a number of horizontal retail and generator mergers under section 50 of the TPA and believes that the TPA has been effective in these cases (ACCC/AER submission no. 35, page 20).

The majority of submissions to ERIG noted that section 50 of the TPA is effective. None of the submissions provided a substantive case for specific changes to section 50 or any other part of the TPA.

As the Freehills submission to ERIG concluded:

“In our view, section 50 is adequate to deal with energy mergers. There is no case for industry specific measures and no evidence that section 50 has failed in this industry” (Freehills submission no. 18, page 10).
However, some market participants have suggested that the ACCC v AGL case potentially provides increased scope for mergers between generators.

In this case, French J defined a NEM-wide market for generation and his decision was also based on his view rejecting some specific arguments concerning intermittent market power in the electricity sector and whether 35 per cent ownership constituted effective control. The Court did not agree with the ACCC’s argument that markets for generation were state-based.

ERIG has not received any evidence that the ACCC v AGL case outcome constitutes a precedent for future cases. The findings of French J have yet to be tested in the context of a significant generation merger.

More generally, ERIG believes that the regulator’s responsibility is to examine each merger/acquisition on a case by case basis, and to provide appropriate evidence to the court to support its view on whether the relevant market is in fact national, or regional, and whether or not the proposed merger will lead to a significant lessening of competition.

In addition, ERIG believes that it is appropriate for the regulator to be subject to the scrutiny of the courts. The fact that the courts do not always agree with the regulator per se is not evidence that the law requires amendment.

On the basis of the evidence available to it, ERIG is satisfied that section 50 of the TPA is sufficient to regulate horizontal mergers that may be anti-competitive. In addition, the TPA provides scope for the merger parties to provide enforceable undertakings under section 87B of the TPA to allay any competition concerns the ACCC may have.

ERIG judges that any limitations associated with the TPA may lie more with difficulties faced by the ACCC when trying to build a case that a proposed merger in complex energy markets would result in a substantial lessening in competition, and in its ability to convince a court of the merits of that case. These difficulties reflect the challenges faced in developing evidence-based arguments relating to future actions that are not observable ex ante.

These difficulties are not unique to energy markets.

Government-owned businesses and the TPA

The ACCC has advised ERIG that the merger provisions in the TPA may not always apply to anti-competitive mergers between government owned businesses.

Were this to be true, it would not seem consistent with practical application of competitive neutrality principles. Whatever the facts of the matter, ERIG believes that consistent application of these laws is crucial for competitive neutrality.

On the basis of advice from the Australian Government Solicitor, ERIG understands that the relevant regulatory framework of the TPA would have a consistent application to both government and private businesses presently operating in the energy sector.

ERIG notes that, as part of broader competition reforms in the 1990s, governments extended the reach of the TPA specifically to include government owned businesses. Section 51 of the TPA provides for certain exemptions to be made by State and Territory law but such exemptions cannot extend to mergers or acquisitions that would be contrary to Part IV of the TPA. ERIG is advised that exemptions from the application of the TPA, to date,
have been limited to joint marketing authorisations for upstream gas projects which are likely to be put in place as transitional measures.

On the basis of evidence received as a result of its own legal inquiries, ERIG has found no evidence that the TPA does not apply in a competitively neutral way, covering both government and privately-owned businesses. Indeed, there has been a case where this was tested in the High Court: the case of *NT Power Generation Pty Ltd v Power and Water Authority* and *Gasgo Pty Ltd*, where the High Court ultimately upheld the ability of the regulator to act under the TPA in relation to government-owned businesses.

However, in advice to ERIG, the ACCC pointed to the additional issue of ‘crown immunity’ as follows:

“The TPA may not apply to mergers between government owned generators, retailers or other government owned entities in the energy sector.

If a merger between government owned entities is given effect through legislation it is likely that ‘crown immunity’ will operate to prevent application of the TPA. The doctrine of ‘crown immunity’ provides that a government is not bound by the effect of any legislation (including the TPA) unless the legislation expressly states or infers otherwise.

Whether or not the TPA applies if a merger is given effect by a scheme of arrangement or any other non-legislated means is less clear. Section 2B of the TPA provides that the TPA applies to a state or territory government enterprise to the extent it is carrying on a business, so in principle the TPA applies if the merger is carried out in the normal course of business. A number of factors are relevant in determining whether a government enterprise is carrying on a business and whether a merger occurs in the normal course of the enterprise’s business activity and these would need to be assessed on a case by case basis. In practice the TPA’s application depends on a number of factors which would need to be assessed on a case by case basis”.

Were the application of the TPA able to be avoided by legislating for structural change (on the basis that such change does not occur in the course of carrying on a business) this would not seem consistent with the practical application of competitive neutrality principles.

Whatever the current situation may be, ERIG is strongly of the view that the TPA, as applied in practice, should deal on a consistent basis with government and private businesses. If in fact there is a possible problem in this area, ERIG concludes that governments should eliminate uncertainty by introducing legislation to remove any ambiguity.

**Government-owned businesses and the Corporations Act**

ERIG has been advised that the application of the Corporations Act to government and private businesses is not even-handed.

Section 5F of the Corporations Act provides for a law of a state or territory to declare a matter to be an ‘excluded matter’ such that it is exempt from the operation of the whole or specified provisions of the Corporations legislation, or is only subject to that legislation to a specified extent.
Under this provision, some states and territories have enacted legislation specifically to limit, or, in the case of NSW, largely to exclude, the application of the Corporations Act to government-owned corporations.

The following are examples of state legislation that exclude state owned corporations from the application of the Corporations Act.

**New South Wales**

A relevant Act in NSW is the State Owned Corporations Act 1989 (NSW) (the SOC Act).

Section 20G of the SOC Act provides as follows:

*A statutory SOC is declared to be an excluded matter for the purposes of section 5F of the Corporations Act 2001 of the Commonwealth in relation to the whole of the Corporations legislation other than:*

(a) *section 1101I (Gaming and wagering laws do not affect validity of contracts relating to financial products) of that Act to the extent that it applies to any contract that is a financial product entered into by an energy services corporation within the meaning of the Energy Services Corporations Act 1995; or*

(b) *to the extent specified by the regulations for the purposes of this subsection.*

Regulations are able to be made under the SOC Act to ‘re-apply’ aspects of the Corporations legislation but ERIG is not aware that any have been made. Section 7B of the SOC Act provides that regulations under the Act may specify excluded matters for the purposes of the Corporations legislation, but ERIG is not aware that any have been made. Section 11A(14) of the SOC Act provides that anything done by Minister acting as a ‘voting shareholder’ is an excluded matter for the whole of the Corporations legislation.

**Queensland**

The Queensland Parliament has enacted the *Energy Assets (Restructuring and Disposal) Act 2006* (Qld) (the EA(RD) Act).

The purpose of the EA(RD) Act is to facilitate the disposal of particular gas and electricity businesses of energy entities (principally Energex and Ergon and related companies), including by facilitating the restructure or sale of the entities (see s 2 of that Act).

Section 47 of the EA(RD) Act provides that:

*Anything done by the Minister under this Act is an excluded matter for the Corporations Act, section 5F, in relation to the Corporations Act, chapter 2D.6*

Part 2D.6 of the Corporations Act deals with officers and employees of a corporation, and, therefore, any action by the Minister under the EA(RD) Act. For example, s11 of the EA(RD) Act enables the Minister to give directions to an energy entity or its board. Subsection 5G(5) of the Corporations Act would then mean that the Corporations legislation does not prevent the directors of the energy entity complying with the direction.
Northern Territory
Section 6 of the Government Owned Corporations Act (NT) (the GOC Act) provides that a government owned corporation is an excluded matter for the purposes of the ‘Corporations legislation’. Regulations are able to be made under the GOC Act to ‘re-apply’ aspects of the Corporations legislation but ERIG is not aware that any have been made.

Western Australia
The Gas Corporation (Business Disposal) Act 1999 (WA) (the GC(BD) Act) deals with the disposal of the business assets of the Gas Corporation established under Western Australian law. Section 12A of the GC(BD) Act provides that matters relating to the constitution, resolutions or shares of any corporate vehicle used to dispose of business assets are excluded matters for the purposes of the Corporations legislation.

Victoria, Tasmania, South Australia and the Australian Capital Territory
ERIG has been advised that none of these jurisdictions have made laws for ‘excluded matters’ for state/territory owned corporations in the energy sector.

ERIG considers that the consistent application of legislation across all business types, irrespective of ownership arrangements, is a pre-requisite for maximising competitive neutrality.

In ERIG’s view, those exemptions that states have put in place are inappropriate. Such exemptions discourage the development of nationally consistent rules and are not readily transparent. ERIG concludes that no future exemptions of this kind should be introduced. Further, existing exemptions should be repealed.

Special ownership rules in the electricity sector
User groups and consumer advocates have suggested the need for special ownership rules to limit mergers in the electricity sector. Such rules have been justified on the basis of the following assertions:

- electricity is special;
- because of its physical non-storability, given current technology;
- because of the requirement to balance supply and demand in real time; and
- because of the potential for firms to exercise market power.

ERIG notes these concerns, but has found no evidence to support the assertion that the electricity market is special from an economic or regulatory perspective. Beyond such assertions, the argument for the imposition of special rules is not supported by any evidence (rules relating to generation/transmission mergers aside). The question of market power in an energy-only market has been examined earlier in this chapter and in chapter 4 above (and see also ‘other matters’ in this chapter below).

ERIG notes that special merger rules are a blunt instrument. They should be used with caution. Prescriptive rules would eliminate flexibility and regulatory discretion which could prevent economically efficient mergers from proceeding.
Such rules could themselves threaten efficient investment in the sector. That is, they could themselves become barriers to market entry.

With the exception of generation/transmission rules (covered earlier in this chapter), ERIG is not persuaded of the case for them.

**ERIG findings on regulatory adequacy**

Vertical integration between contestable market businesses is not a source of uncompetitive market outcomes per se.

Vertical integration between generators and transmission businesses is a legitimate cause for concern. ERIG agrees that governments should promulgate cross-ownership rules proscribing such mergers as soon as possible in the interests of investor certainty. These rules should comply with competitive neutrality principles.

ERIG has received no evidence that excessive horizontal aggregation within the Australian energy market is a problem at present, at least for jurisdictions where assets are owned by the private sector.

For privately-owned businesses operating in contestable markets, ERIG has received no evidence that the TPA is inadequate.

There is ambiguous evidence about the applicability of the TPA to government-owned businesses. Given the importance of competitive neutrality for efficient market outcomes, ERIG concludes that any such ambiguity should be eliminated as soon as possible, via state legislation if necessary.

An alternative option that would eliminate this ambiguity is privatisation.

ERIG has received evidence that the Corporations Law does not apply equally to state government and to private businesses, because of ‘carve-outs’ in some states limiting or excluding the application of the Corporations Law to the former. This undermines competitive neutrality and market efficiency. ERIG concludes that such ‘carve outs’ should be removed by appropriate state legislation as soon as possible.

An alternative option that would eliminate this problem is privatisation.

Apart from proscription of generator/transmission mergers, ERIG has received no evidence supporting the case for special ownership rules in the electricity sector.
Market Structure Recommendations: regulatory adequacy

The following recommendations are designed to improve the efficiency of Australia’s energy markets by tightening the application of pro-competition regulations.

3. Improving regulatory adequacy

3.1 Proscription of generator/transmission mergers

ERIG agrees with the 10 February 2006 COAG decision to proscribe generator/transmission mergers. ERIG recommends that this policy – still being developed by the MCE – should be announced as soon as possible to remove avoidable investment uncertainty. ERIG also recommends that this policy should apply equally to government and privately-owned businesses.

These recommendations apply to COAG and all states and territories.

3.2 Removing ambiguities in the coverage of the TPA

ERIG recommends that any ambiguities or uncertainties about the application of the TPA to government-owned businesses – eg, due to ‘crown immunity’ considerations – should be removed as soon as possible through appropriate state legislation.

This recommendation applies to COAG and all states and territories.

3.3 Applying the Corporations Law consistently

Substantial ‘carve-outs’ from full application of the Corporations Law to government businesses currently apply in three states and one Territory. These confer a potential competitive advantage on government businesses relative to private competitors, undermine good governance, and weaken even-handed application of competition regulation.

ERIG recommends that these ‘carve-outs’ should be abolished through appropriate state/territory legislation. (See also recommendation 1.5.2)

This recommendation applies to NSW, Queensland, Western Australia, and the Northern Territory.

Matters on which ERIG makes no recommendations

Vertical integration between generators and retailers is not considered by ERIG to be a problem. Were it to become a problem, this would reflect excessive horizontal aggregation, rather than vertical integration per se.

ERIG has received no evidence that horizontal aggregation in the electricity sector is a problem at the present time. Nor has ERIG received evidence demonstrating that the TPA is inadequate (subject to recommendation 3.2 above).

ERIG has received no evidence demonstrating that special ownership rules are required in the electricity sector, apart from those addressed under recommendation 3.1 above. The case in principle for legislated separation of retail and distribution asset ownership is greatly weakened in practice because privately-owned retail/distribution assets are being separated by the market. The remaining issue in this context is the treatment of government owned retail/distribution assets. Continual monitoring of developments will be needed in future.
The only barrier to entry cited by private investors not addressed in ERIG’s market structure recommendations is that due to uncertainty about government policy on greenhouse gas emissions. (On this, see ERIG’s comments in this chapter under the heading ‘other matters’ below.)

In the time available to it, ERIG has not investigated the adequacy of the TPA in relation to ownership of gas assets, and gas/electricity assets. This matter may require further investigation.

**Other matters**

Market participants have noted there is a debate about whether or not energy-only markets can deliver adequate and competitive energy supply on a sustainable basis. While this debate is inconclusive, this matter needs monitoring in future. ERIG believes freeing-up Australian energy markets will help policy-makers to better judge whether or not this is a practical problem.

Greenhouse gas abatement policy as a source of investment uncertainty has already been noted. This is being considered both within Australia and overseas. ERIG has not comprehensively analysed this matter. ERIG notes that, however it is delivered, a global price signal – a price faced by carbon emitters – is needed to reduce this source of investment uncertainty and to deal effectively with greenhouse gas emissions.

The evidence of intermittent market power suggests that there is a current problem, especially, apparently, in NSW. What is not clear is how best to address this problem. On balance, ERIG concludes that, for now, market reforms that concentrate on structural improvements to the energy market: that is, a combination of disaggregation/privatisation, enhanced competitive neutrality, improved governance, and enhanced regulatory adequacy, should be pursued first.

**Market sustainability**

Some market participants have noted that there is a debate about whether or not energy-only electricity markets can be sustainable – that is, effectively signal and induce adequate investment in the supply growth needed to meet demand growth on a competitive basis.

In the time available to it, ERIG has not investigated this matter in any detail.

However, ERIG notes that:

- the academic literature covering this debate at present is inconclusive;
- in principle, a properly-working energy-only market should see the price-duration curve settle at levels sufficient to induce adequate investment into the market to meet demand on a competitive basis;
in practice, including within Australia, electricity markets do not operate freely at the present time. When demand pushes up hard against capacity, governments may intervene to deal with specific problems. Prices (eg, retail prices) are not always completely free to adjust to market conditions. As noted throughout this chapter, within major NEM jurisdictions, government ownership may also affect investment; and

this matter will require monitoring in future.

That said, ERIG considers that implementation of the recommendations in this report will make Australia’s electricity markets more competitive, responsive and flexible. This will allow a better assessment of the ability of these markets, when allowed to operate properly, to deliver adequate and competitive supply.

Armed with this information, policy-makers should be able to make better-based assessments about the sustainability of properly-working energy-only markets in future.

Greenhouse gas abatement policy

Investor uncertainty about greenhouse gas abatement policies as a barrier to electricity market investment has been noted earlier in this chapter.

In the time available to it, ERIG has not been able to undertake a comprehensive analysis of this problem.

However, ERIG notes that policies to deal comprehensively with this problem are currently being examined both within Australia and overseas. They have also been noted in other reports (eg, The Uranium Mining, Processing and Nuclear Energy Review 2006; and Economic Impact of Climate Change Policy: the role of technology and economic instruments ABARE 2006).

For the purposes of this report, ERIG notes that:

» greenhouse gas emissions and climate change are global problems;

» a globally-inclusive policy response is needed to deal with them;

» unilateral action by Australia is unlikely to contribute significantly to global greenhouse gas abatement per se, even if it has some ‘signalling value’ encouraging others to act as well, because of ‘carbon leakage’ effects;

» whatever the mechanism chosen, effective solutions require a price signal: effectively a price to be paid by those responsible for carbon emissions;

» mechanisms that do not imply a price on carbon emissions are unlikely to deal with greenhouse gas problems, and a zero carbon price is unlikely to deal with investor uncertainty in relation to energy markets; and

» subsidising low-emission energy technology is a risky alternative policy course. It involves governments ‘picking winners’ rather than letting technology deliver the most cost-effective responses. It does not deal effectively with investment uncertainty if such policies are not themselves stable over very long periods of time. Instead, it replaces one type of investment uncertainty (policy response risk) with another (policy durability risk).
Dealing with persistent but intermittent market power

ERIG has found some evidence that is suggestive of non-competitive market outcomes having an adverse impact on the economic performance of the NEM (see chapter 4 above). This appears to be especially the case in NSW.

That said, individual behaviour of generators within the NEM, in compliance with the NEL rules, is not illegal under the TPA.

To the extent that barriers to entry are the underlying causes of such outcomes, these can be dealt with either by disaggregation of businesses (where these are government-owned) and/or by privatisation.

ERIG does not believe that changes to the TPA are an appropriate response at this stage. ERIG notes that, overseas, competition issues (eg, market power mitigation) are explicitly covered within market design and operating rules, rather than through adjustments to competition policy instruments such as the TPA.

With the exception of the requirement that generators bid ‘in good faith’, the NEL currently does not address market power specifically, or even the conditions under which it would be appropriate to do so. This appears to be in contrast with ‘best practice’ considerations for managing unilateral market power in electricity markets (see, for example, Wolak 2006).

That said, ERIG notes that the current design of the NEM has delivered significant benefits. In an energy-only market, it is important not to interfere with the role of the price mechanism in driving the long term sustainability of the industry. Nevertheless, the design of the NEM is also intended to deliver reasonably competitive outcomes.

The available evidence of intermittent market power suggests that there is a current problem, especially, apparently, in NSW. What is not clear is how best to address this problem. On balance, ERIG concludes that, for now, market reforms that concentrate on structural improvements to the energy market: that is, a combination of disaggregation/privatisation, enhanced competitive neutrality, improved governance, and enhanced regulatory adequacy, should be pursued first.

Once these reforms have been implemented, governments will have an opportunity to evaluate the extent to which residual market power problems exist, and, in keeping with the scale of those problems, the need for further reforms.
6 Transmission

Overview

This chapter provides an overview of the current framework under which the transmission network is developed in the NEM today. The transmission system development cannot be separated from the overall power system operation or development and therefore from operation and investment in generation, or from decisions by customers and the broader energy market. The discussion leads to ERIG’s views that:

» the current level of transmission and interconnection investment in the NEM is reasonably appropriate for the current installed generation capacity and peak demand; and

» the key policy question for ERIG is to ensure the regulatory regime, incentives, pricing and approvals processes all work together with the overall planning and governance structures to achieve an economically efficient mix of generation and transmission investment. An efficient mix of investment will provide the lowest sustainable cost of energy delivered to customers, whilst maintaining a reliable and secure power system.

Shortcomings of the current arrangements

The chapter then seeks to identify shortcomings in the current regime finding that:

» whilst the general level of investment is reasonably appropriate and no new major interconnectors appear economical at present, the mechanisms are not in place to ensure the efficient ongoing development of the national transmission system. There is evidence that inefficiencies have been caused by the lack of such mechanisms and efficient investment opportunities have been missed as a result. The greater concern, however, is to ensure that the current arrangements are substantially improved to ensure the future challenges can be efficiently and effectively met.

ERIG has identified shortcomings in three critical elements of achieving an efficient mix of generation and transmission investment across the national grid:

» the need to improve the commercial incentives on generators to locate efficiently;

» the need for improved incentives for both efficient operation of the existing transmission system and efficient investment in a market context; and

» a requirement for coordination of investment in the transmission system on a national basis.

The way forward

The chapter then addresses the shortcomings in the current regime and identifies specific initiatives to address them.

The role and function of the Regulatory Test has a number of critical shortcomings. While the investment decision making criteria within the Regulatory Test are appropriate, the two criteria for investment, currently applied as separate limbs, should be amalgamated. The
Regulatory Test itself, however, does not currently perform the role of a test and its links to the regulatory regime are tenuous at best. ERIG considers that the Regulatory Test should be replaced with a two step process to guide efficient transmission investment as follows:

- a National Transmission Network Development Plan should be developed which aims to deliver an integrated, national plan for the longer term efficient development of the transmission network which is consistent with the efficient development of the overall power system, and;
- the Plan would be designed to inform the setting of the revenue allowance provided for TNSPs for a regulatory period. Within that period, each project would be subject to a Project Assessment and Consultation process prior to being constructed.

ERIG sees efficiency gains from removing current differences in reliability standards and how they are applied across the state jurisdictions.

ERIG considers that the potential benefits from better coordinated development of the national transmission grid are sufficient to warrant the establishment of a national planning function. After reviewing a number of options, ERIG concludes that planning model could be either:

- a National Transmission Planner – involving a strategic national planner to collate, analyse and disseminate information and deliver strong and well informed independent advice on efficient investment across the NEM as a strategic national plan; or
- a National Transmission Service Procurer – involving the establishment of a NEM-wide, not-for-profit corporate entity responsible for undertaking national planning, making augmentation investment decisions and procuring those services either by negotiation or tender.

The National Transmission Planner model as proposed would seek to complement the existing arrangements in most states and maintain current accountabilities. This option is consistent with the proposed incentive based regulatory regime. The National Transmission Planner model is outlined and recommended along with discussion of the processes required to implement the associated regime.

The governance reforms to NEMMCO proposed by ERIG in chapter 5 provide an opportunity for this new national planning function to be incorporated within that body rather than embarking on the creation of a new body. While there will be a need to ensure any conflicts of interest are minimised, the co-location of the planning function with the system operation function would benefit from some synergies and cost savings. However the planning function would need to be established anew with a stronger focus on involving all parties in the development of plans. This option will only work effectively if the governance reforms proposed by ERIG are implemented.

The option of a National Transmission Service Procurer is not ruled out by ERIG and may be a preferred option if states decide to pursue ERIG’s preferred asset ownership changes as suggested in the chapter 5. A review of transmission planning in the future is recommended and if the appropriate incentive regime has not been successfully implemented, the case may be made to move to the National Transmission Service Procurer model at that time.
Western Australia

The analysis and discussion and the initiatives proposed in the majority of this chapter relate to the interconnected states in the NEM. Western Australia’s power system is separate from the NEM and will remain so in the foreseeable future. The market arrangements in Western Australia are different from those in the NEM. The final section in this chapter briefly considers application of ERIG’s thinking to the Western Australian arrangements.

Introduction

In examining the transmission framework of the NEM, ERIG has sought to maximise all four limbs of economic efficiency as defined in chapter 2. This has meant that ERIG has sought to maximise efficiency in the short term and also in terms of long term allocative and dynamic efficiency. ERIG has strived to develop options that will ensure the continued efficient development of the entire electricity system over the longer term.

The NEM has performed well to date. ERIG is of the view that the current level of transmission and interconnection investment is reasonably appropriate for the installed generation capacity and peak demand. However, failure to ensure efficient investment in generation and transmission on a system wide basis into the future puts at risk the efficiency gains achieved as a result of previous energy market reforms.

The timely and efficient delivery of transmission services is crucial to enabling the electricity system to meet the emerging challenges posed by Australia’s future energy demands. It is also important that there is efficient investment in both the level and location of generation to meet customer demand. Estimates suggest that around 1,000 MW of additional generation capacity is required every year for the next ten years to meet demand growth. To maintain and build on the benefits of the reforms to date, this investment and the related transmission investment will need to deliver an efficient overall power system.

Consolidating the existing efficiency benefits of reform and maximising potential future benefits requires the right drivers and incentives to be applied to all sectors of the electricity system. To ensure efficient investment in both generation and transmission, the regulatory regime, planning structures and the National Electricity Rules (the Rules) need to be formed on a fully national and efficient basis and need to be sufficiently flexible to be able to respond to future challenges.

The transmission network provides the physical backbone of the interconnected national electricity market and is essential to the competitive, efficient and reliable performance of the market. In its report to COAG in December 2003 the MCE agreed that further reform should be undertaken, including to:

“Improve the planning and development of electricity transmission networks, to create a stable framework for efficient investment in new (including distributed) generation and transmission capacity.” (MCE 2003)
As part of the November 2005 MCE transmission reform package, it was noted that interaction of the various elements of the transmission work program should seek to enhance investor certainty, consistent with the objective for this sector, as agreed by COAG in 2003.

ERIG does not consider that increases in transmission capacity to avoid short term regional price differences or to support inefficient locational decisions by generators necessarily delivers economically efficient outcomes for the market as a whole. While some static efficiency gains may be available from this approach, ERIG agrees NGF that there are negative implications for long term allocative and dynamic efficiency. ERIG considers that such a policy direction is economically inefficient and detrimental to the market and the long term interests of consumers.

The development of an economically efficient and fully national market is not solely a matter for transmission planning and investment. The development of such a market is also dependent upon competitive markets in each region, open access on a level playing field across the market and well functioning financial markets. These matters are dealt with in the other chapters of this report. ERIG considers that designing an electricity framework on these principles will assist policy makers in developing a national energy market, delivering efficient investment and operation across both electricity and gas markets.

The transmission framework today

Following the competition reforms of the 1990s and more recent energy reforms, transmission services are supplied under the following framework:

- an open access and common carriage regime;
- an economic regulatory framework to determine allowable revenue; and
- a transmission use of service (TUOS) pricing framework that charges customers only for the use of the shared transmission network.

The arrangements are outlined in the following sections and are described in more detail in Appendix 8 Transmission planning and regulatory arrangements.

Current economic regulation framework

The AER regulates the revenue of TNSPs under chapter 6 of the Rules. Under this regime, reliability obligations are set and revenue is regulated to allow the regulated entity to meet a given service standard. It should be noted that the vast majority of the required capital expenditure allowance is driven by state based reliability requirements on TNSPs.

The incentive properties of the regime are based on the transmission provider retaining, during the regulatory period, the difference between its actual expenditure and the forecast costs used to set the revenue determination while continuing to meet standards.

However, Victoria has derogated away from the national regulatory regime contained in the Rules. In Victoria, the majority of transmission assets are owned and operated by the privately owned SPAusnet. SPAusnet has responsibility for the ongoing replacement and refurbishment of assets and some augmentation projects. The responsibility for planning the
development of the network and making decisions on significant new augmentations lies with a not-for-profit entity, VENCorp.

Current Service Standard Arrangements
Transmission providers face statutory reliability obligations. In addition, they can currently also earn (or lose) up to 1 percent of their regulated revenue for exceeding (or under-performing) given performance targets. These standards are currently only related to the physical performance of their assets rather than their market impacts. The capped incentive will increase to a maximum of 5% at the TNSP’s next revenue reset, in line with the new Rules governing revenue regulation.

Transmission pricing to consumers
The current transmission pricing arrangements provide for half of the revenue allowance for each TNSP to be recovered in the relevant state through locational Cost Reflective Network Pricing (CRNP) and the remainder as a general usage charge. In addition, there are currently charges for connection (entry and exit) and a common service charge for overheads.

These fixed annual charges are allocated to connection points based on the annual costs of the network assets deemed to be used to provide the service to that connection point. The costs are then recovered from customers in each jurisdiction. Except for a few large customers who connect directly to the transmission system, customers pay these charges through their distribution prices. In most cases, any locational signal that may have existed in the transmission price, is largely diluted through the use of “postage stamped” distribution charges.

AEMC Review of Economic Regulatory Framework
The economic regulatory framework for transmission was the subject of an AEMC statutory review, finalised in November 2006 and published on 21 December 2006. The final Rule determination contains a prescriptive process and methodology for making a revenue determination. Under this regime, the AER must be satisfied that a TNSP’s estimate of its future revenue requirements reasonably reflects its efficient and prudent costs. The revenue requirement over the regulatory control period includes operating costs and the impact of capital spending over the period.

The Regulatory Test
The current regulatory regime includes a requirement for network service providers to ensure any proposed augmentation passes the “Regulatory Test”. The Regulatory Test is broken into two limbs:

» the reliability limb which is used for considering network augmentations determined to be necessary to meet customer reliability standards. An augmentation satisfies this limb if it represents the least cost option when measured against a range of credible alternatives; and

» the market benefits limb which is applied to other proposed network investment. A new network augmentation satisfies the market benefits limb of the Regulatory Test if it maximises the net present value of the market benefits having regard to alternative options, timing and market development.
Proposals for large network augmentations costing more than $10 million must satisfy one of the two limbs of the Regulatory Test before being constructed. Currently, over ninety percent of network augmentations undertaken by TNSPs are conducted using the reliability limb of the Regulatory Test.

Although the Regulatory Test is often promoted as a key component of the regulatory regime, progressive changes to the overall regulatory regime have eroded its importance. The emerging role of the Regulatory Test is discussed under The Way Forward. The AEMC has recently drafted Regulatory Test principles which largely reflect the approach of the current Regulatory Test, but slightly alter the consideration of options under the test.

Current transmission planning arrangements

Intra-regional planning arrangements and obligations
The Rules contain some high level reliability standards. However these are very broad and each jurisdiction has additional and different requirements. The jurisdictional standards are developed by different bodies in each state and these standards generally leave considerable scope for interpretation and application by the relevant TNSP within each state.

All TNSPs are required to develop an Annual Planning Report (APR). The APR assesses the adequacy of the transmission network to meet load growth forecasts for that jurisdiction. Differing standards, different interpretation of standards and planning by individual TNSPs allows for very different standards of supply across jurisdictions.

TNSPs plan and develop their networks over time to maintain compliance with reliability obligations as demand grows. Different reliability standards apply in each jurisdiction, both in form and in level. In NSW and Queensland, the reliability standards are set in deterministic terms, such as “N-1” style criteria. In Victoria, VENCorp applies a probabilistic approach to network planning. South Australia applies a method similar to the probabilistic approach for each connection point and then translates the results of this analysis into deterministic planning standards for individual connection points.

Inter-regional planning arrangements
Inter-regional planning is coordinated between responsible jurisdictional planning bodies affected by any proposal for an inter-regional transmission augmentation. A jurisdictional planning body has the option to seek technical advice from the IRPC.

The IRPC is established by NEMMCO under the Rules and consists of a NEMMCO representative as convenor and a representative from the nominated planning body in each jurisdiction. Although there is provision for the appointment of additional personnel to the IRPC, NEMMCO has not chosen to do so to date.

The Annual National Transmission Statement
The ANTS was first published in 2004. The ANTS replaced the Annual Interconnector Review, which was originally published by the IRPC.

The ANTS relies heavily on information from the TNSPs’ Annual Planning Reports and from NEMMCO’s Statement of Opportunities and is an attempt at providing a high-level integrated overview of the potential value of further development of the national transmission flow paths over the next ten years.
Delivering a fully national and efficient system

The COAG Communiqué which established ERIG requires an examination of the transmission arrangements to achieve a “fully national transmission grid”. In turn, this requires a determination on what is meant by a “fully national transmission grid” and what characteristics such a grid would display. The character and performance of a transmission grid cannot be assessed in isolation of the location and capacity of generators and of the loads they seek to serve.

The examination begins with an assessment of whether Australia currently has a fully national transmission grid, noting that this section only refers to the transmission system in the NEM. What constitutes a “fully national transmission grid” will always be a moving target as the power system responds to the challenges of meeting Australia’s future needs for energy. ERIG has therefore sought to examine whether Australia has the arrangements in place in both the regulated and competitive sectors of the industry to ensure the ongoing development of an efficient fully national power system.

Defining a fully national and efficient transmission system

ERIG considers that a “fully national transmission grid” should contribute to an outcome where:

» the energy supply framework in all states across both gas and electricity is efficient, supporting competition and open entry;

» the national transmission network is utilised to its fullest by appropriately motivated network service providers;

» appropriate planning functions coordinate efficient network development within and between regions;

» there is a level playing field between alternative investment options including transmission, generation and demand side opportunities and between operational and investment approaches;

» well functioning financial markets support commercial trade across the national market;

» appropriate information functions provide all participants with the information necessary to take economically efficient investment and operational decisions;

» valuations from forward financial markets and the congestion management regime drive efficient market oriented investment within and across regions; and

» energy infrastructure delivers secure and reliable services to all Australians.

Importantly, ERIG considers that a fully national and efficient transmission grid is one that is responsive to the needs of, and supported by, the competitive sectors of the market. This suggests that the transmission grid should be constructed, operated and maintained in such a way as to minimise the overall cost of delivered energy to consumers, both in the short (operational) and long (investment) terms, subject to it providing a given level of reliability.
Adequacy of the current system

It is recognised that the transmission network can often be constrained in its operation and lead to some price separation. The national grid spans a very long geographic distance with major loads and generators spaced along it. As such, at some times, constraints in the network are to be expected and the resultant price signals should indicate to prospective generators (and customers) the most attractive location for any new investment.

Augmentation of the transmission network would be efficient if the difference in the cost of generation at two points was greater than the cost of augmenting the transmission service between those points. Augmentation may also be justified on the basis of the competition benefits arising from the link.

A number of studies have been undertaken to address questions as to whether various interconnector augmentations are, or may be, justified. These include the ANTS published by NEMMCO and verification studies undertaken subsequent to, or as part of, the ANTS in association with the IRPC. They also include specific studies undertaken by consultants or TNSPs and applications of the Regulatory Test to certain proposed projects. ERIG has considered a number of these, including several unpublished studies.

The ANTS seeks to provide “an integrated overview of the current state and potential future development of national transmission flow paths (NTFPs). NTFPs are the main transmission corridors within and between the jurisdictional transmission systems.” The ANTS is developed by NEMMCO using market simulations (spanning 10 years) and produces a series of indicators signalling the potential market benefits for network augmentation.

These scoping studies are then used to prioritise augmentation opportunities. Jurisdictional Planning Bodies propose conceptual augmentations that deal with some, though not all, projected congestion points on those priority flowpaths and these are analysed to gauge their likely value. These verification studies in the 2006 ANTS indicate that the net market benefits from each of the conceptual augmentations were “marginal to insufficient”.

This is consistent with other, more specific studies, considered by ERIG in its analysis. None of these studies indicate that the market is currently being denied a major interconnector upgrade which is otherwise justified on the basis that it provides net benefits to the market. Network investments are generally very long term investments and should not be justified on the basis of short term variations in prices. High prices in a particular area of the NEM should be dealt with in the most efficient manner, either though generation, demand side or network investment.

The verification studies in the 2006 ANTS do indicate however, that the conceptual augmentations examined “only deliver a portion of the potential market benefits identified by the scoping studies. The scoping studies indicate that the present value of total market benefits (excluding competition benefits) of relieving all network congestion in the NEM from 2009/2010 onwards… would be around $2.2 billion.”

The scoping studies in the ANTS are used to identify potential areas of future constraint in the national transmission grid for further examination. They are described by NEMMCO as being a preliminary view which “provides an upper estimate of the value of relieving network congestion (excluding competition benefits)” [2006 ANTS, section 8.3]. The figure
is nevertheless indicative of a significant amount of congestion being forecast to occur in the future without further transmission investment. Importantly the ANTS shows that the majority of these potential benefits lie outside the core interconnector investment projects put forward.

The AER has progressively published a series of reports seeking to quantify the current cost of constraints. The work is not aimed at identifying whether or not any congestion currently experienced is able to be efficiently remedied by action or investment of the TNSPs. It does, however indicate a modest total cost of constraints in the market. This work is further discussed in the section “The commercial risk of inter-regional trade”.

Interaction between regulated and competitive sectors

It is recognised that transmission investment is often a competitor to both local generation and other alternatives, such as demand side options. Power flows on a transmission network reflect differences in the location of the demand from the location of generators seeking to meet that load. Those powerflows must not exceed secure limits and, from time to time this requires constraining powerflows to those limits resulting in congestion. Some congestion is efficient and even inevitable when practical operating arrangements are taken into account.

To seek to completely remove the risk of congestion arising at any time would accept a need to design the power system so that at all times any power station should be able to physically supply any load. Such a power system would require significant amounts of additional capacity to meet short periods of peak demand. The capacity required to meet peak demand would, by definition, be underutilised for most of the time and on that basis would not be efficient.

Congestion on the network does, however, raise costs and therefore steps need to be taken to ensure it is consistent with efficient operation and investment, and that commercial implications can be efficiently managed in the financial market. These matters are discussed further in the chapter 7. In the first instance we need to ensure that the regulatory regime, incentives and prices lead to the most efficient use of the network already in place. This requires appropriate measures on both the TNSPs who supply the network services and the generators who use them.

Congestion can also be caused by the unavailability of transmission plant or where less than the efficient level of service is offered by the assets. The regulatory regime covering TNSPs needs to provide market based incentives to maximise the network services they provide to the market at times the market values them most. In addition, congestion management schemes need to provide incentives for generators to efficiently use the network. In a number of cases in the national network, congestion is arising as a result of poor congestion management and may not represent an efficient or even sensible outcome.

The need for appropriate incentives is even more important in terms of the longer term efficient development of the power system. Here the economic regulatory regime, incentives, pricing and approvals processes need to work together with the overall planning and governance structures to achieve a mix of generation and transmission investment which will provide the lowest delivered cost of energy to consumers.
This directly underpins the high level principles of ensuring there is a level playing field for operational and investment decision making across regions and between technologies. Accordingly, ERIG considers that the questions of how best to ensure a level playing field, identify the most efficient solution to meet rising demand and to ensure that this will continue to deliver a fully national and efficient transmission grid are the key strategic issues that needs to be addressed.

The principle of economic efficiency and the interaction between the competitive and regulated sectors was captured in the NGF submission which stated that:

“The NEM objective applies to both the competitive energy market and regulated network market. Consequently the two investment streams are inextricably linked and can’t be considered in isolation from one another if the total cost of assets required to meet the NEM objective is to be minimised” (NGF 2006).

Further, ERIG considers that the regulatory regime should provide scope and incentives for TNSPs to maximise the network services they make available to the market in a manner that lowers the overall cost whilst maintaining system security. In this regard, the potential use of network control schemes and the provision more generally of Network Control Ancillary Services (NCAS) should be encouraged when economic. There should be incentives in place to reward TNSPs for utilising real time ratings on transmission lines, implementing improved protection schemes and for making strategic investments that deliver market benefits.

The investment drivers on both the regulated and non-regulated sectors should be mutually reinforcing and closely aligned. In terms of the regulated sector, this means that the expenditure drivers delivered through the regulatory regime and the approval processes need to take account of the impact on the competitive market. These drivers should also take account of the benefits to the national market, over and above those derived from meeting reliability requirements.

**Delivering a transparent and robust planning regime**

The national transmission network is large and exhibits complex interactions between elements that can have a significant impact on its capability. Arrangements for transmission planning should provide a genuine national (NEM) focus and seek to identify strategic network investments that maximise the value of the transmission system to the national market. Just as the network cannot be viewed on an area by area or a state by state basis, the planning of the network needs to integrate the need to meet customer reliability standards with the need to maximise the net benefits it delivers to the market.

The competitive sector relies upon the regulated natural monopoly networks to deliver energy to the market. Operational and capital expenditure decisions of the regulated entities have an impact on the operation of the competitive sector and, as a result, on the commercial operation of merchant players. Consequently, the planning processes and the information that is provided to stakeholders through this planning process are crucial to the efficient operation of the system as a whole.

ERIG considers transparent information provision to be a critical element of an efficient national energy market irrespective of whether it relates to the regulated or competitive elements of the market. Transparency in the provision of information is one of the corner-
stones for driving competitive and efficient outcomes and underpins investor confidence. The arrangements for transmission planning need to involve participants in the competitive market in the development of an efficient, national power system and in doing so, improve transparency and investor confidence.

It is therefore the view of ERIG that the framework for transmission planning should, to the greatest extent possible, facilitate the efficient delivery of appropriately located and timed transmission capacity consistent with the needs of the competitive market and the reliability requirements of electricity consumers. Further, given that the electricity transmission network is in fact a single system, transmission planning should at the very least be co-ordinated across that entire system.

Appropriate governance structures

Governance arrangements are fundamental to give effect to the policy intent of any operational framework. Delivering effective operational outcomes requires clear lines of responsibility and accountability for all participants and responsible institutions.

A critical factor in the choice of governance arrangements is the degree to which investors are confident that the key institutions, including the entities responsible for transmission planning and system operation, operate in a transparent and independent manner. Governance is further discussed in the chapter 5 and chapter 7.

Impediments to the delivery of a fully national and efficient system

ERIG has identified a number of gaps that could impede the delivery of a fully national and efficient system. ERIG considers that a narrow focus on the current planning arrangements alone would be unlikely to address ERIG’s objective of delivering a fully national and efficient grid. In arriving at this conclusion, ERIG has considered not only how transmission planning is conducted, but how it interacts with both the investment and operational decisions across both the regulated and competitive sectors of the NEM.

Identified issues are grouped under the following four key headings:

» operational and investment drivers on the contestable sectors;
» network operation and investment;
» national focus and strategic network planning; and
» investor certainty and cross-sector neutrality.
Operational and investment drivers on the contestable sectors

The current transmission common carriage framework gives generators open access to the transmission system, subject only to the cost of connecting to the common network (shallow connection costs). There is currently no exposure to the cost of increased congestion on the common network as a result of generator investment decisions (deep connection charges). Generators do, however, face average marginal losses and a substantial risk of their output being constrained.

Under these arrangements, a key driver (other than fuel source considerations) on the location of new generation investment is the projected extent and commercial impact of transmission congestion. If the balance of the framework is to remain unchanged, the effectiveness of using congestion to drive locational decisions for generators is contingent on the ability to price that congestion and then expose generators to that signal.

Intra-regional congestion

A direct consequence of the NEM regional design is that intra-regional congestion is not currently priced. Many stakeholder submissions indicated that the current regime for providing locational signals for generation investment is flawed. ENA considers that the approach adopted by ERIG should include the introduction of some level of cost reflective, locational pricing for all generators (ENA 2006). This is also discussed in chapter 7.

The lack of coherent arrangements to price and manage intra-regional congestion impacts on the operation of the market on a daily basis and the longer term. It also increases the risks to both existing and proposed new generators. Delta Electricity, in its submission to ERIG’s Issues Paper, noted that if a new entrant generator only caused an increase in network congestion, but did not affect customer reliability, the TNSPs would not have an obligation to mitigate the congestion.

The ability of a generator to influence network congestion can be addressed by increasing network capacity. However, ERIG notes that the costs involved in increasing the network capacity to alleviate all congestion are likely to be prohibitively large. Further, ERIG notes that alleviating all congestion would remove the only current signal for the efficient location of generation thereby risking future inefficiencies.

A regime which guaranteed the removal of congestion in the future, coupled with a transmission pricing regime which does not charge generators for that service, would bias the choice of technology towards remotely located generation, ahead of local generation options or other alternatives such as demand side response.

Such a solution would substantially decrease the long term allocative efficiency potential of the electricity sector. Accordingly, ERIG concludes that this is not an efficient solution and may not align with the NEM objective with respect to serving the long-term interests of consumers.

Whilst the non-firm access to dispatch and the existence of congestion provides some form of regional locational signal for generation, an issue remains with regard to the lack of a congestion price for intra-regional transmission elements. The issue is exacerbated by the interaction of network elements.
Despite commonly referring to intra-regional transmission as different from interconnectors and intra-regional constraints as different from inter-regional constraints, there is no physical distinction in practice. Many constraints within a region have both an intra-regional and inter-regional impact and this recognition led to the debate over several years as to the general form constraints should adopt.

The decision has been made to implement fully co-optimised direct physical representation of constraints in the market to maximise control and system security. The nature of these constraints and their interaction with the regional market design can create inefficient drivers on the bidding behaviour of generators strategically located in the transmission system.

Even more concerning in terms of the longer term efficient development of the market is that unpriced congestion can create perverse locational incentives on investments in new generators. In some circumstances, this can lead to strategically located generators using anomalies between optimised dispatch based on bids and regional settlements to effectively gain preferential access to the transmission system. This preferential access enables participants to shift “volume risk” within a region and “volume and price risk” across regions to other participants. There are examples where investment, or proposed investment, has been influenced in this regard. An outline of the general issue is set out in box 4.

**Box 4: Congestion pricing and efficient generation location**

**12 Generation location and region boundaries**

The illustration above shows a generator G1 in region A located strategically on the network such that it effectively is on the interconnector between Region A and Region B. The actual constraint in this example is between generator G1 and its regional reference node (RRN A) rather than at the regional boundary. In this case, a fully optimised
constraint should be used to ensure the line between G1 and the node does not exceed its secure operating limit. A fully optimised constraint will trade off the bid cost of imports across the regional boundary with the bid cost of generation from G1.

Optimising imports and G1 in this way manages security but does not drive price discovery in the bidding and dispatch process. Generator G1 in this example could bid low, even as low as technically allowed (-$1,000/MWh) knowing the price it will be paid for any output will be the regional reference node price at RRN A. In a region with a number of other generators, there is little risk that the price bid by G1 would set the price at RRN A. Generators G2 and G3 in the adjacent region are not as fortunate. The value of imports is closely related to the clearing price in their region and they would not be competitive with a bid of -$1,000/MWh. In this case, whenever generator G1 wishes to generate it can bid low and effectively block out any competition from generators G2 and G3 on the same transmission line. This situation, and a number of similar but more complex situations, currently exists in a number of locations in the national market. The intensity of the debate on the formulation of constraints highlighted the commercial importance of such situations.

The current arrangements not only affect short term market efficiency and equitable competition between participants but have the potential to incentivise new generation investment to identify and locate within similar network conditions. A number of new generation investments draw commercial advantage from building at such a situation. ERIG is aware of one proposed generation investment where the proposed location would have induced network congestion. The proposed generator would hold a strategic advantage as a result. In this case a relatively small change in the proposed location would have removed the risk of such congestion, but the incentives on the proponent were the opposite.

In its 2005 APR, TransGrid states:

“At times when NSW is a heavy importer of power from the south the line ratings within the Snowy system and immediately north of Snowy may impose a limitation. The development of any generation in the south west of NSW (such as gas turbines in the Wagga area) will impose greater competition for the limited power transfer capability to the north. Such generation does not provide an effective increase to the net NSW generation at times where the transmission system is limiting.”

Despite this, a major new power station is proposed for Wagga.

In the longer term these outcomes are likely to reduce the confidence of investors in the integrity of NEM pricing outcomes and contribute to ill timed or inappropriately located investments, all of which will waste scarce resources and add costs to customers.

ERIG does not argue that the form of the constraints used should be changed. Rather the weakness of locational signals to generators needs to be addressed. Aligning the commercial incentives of generators with the capacity of the existing network removes the generator incentive to use network congestion to extract commercial advantage, and contributes to a more efficient use of network infrastructure. Consequently, it is important
that the regional pricing arrangements do not undermine the creation of incentives for efficient operational and locational investment decision-making.

Failure to improve locational pricing signals for generators will directly undermine any long term allocative efficiency benefits through inefficient investment location and will lock in those inefficiencies for the life of the assets.

The commercial risk of inter-regional trade

ERIG notes that, unlike intra-regional congestion, inter-regional congestion is priced. The cost of this congestion has been the subject of some debate. Estimates of the cost of congestion have ranged from $10 billion since market start (EUAA, 2005) to more modest figures of $36 to $45 million per year published by the AER.

It is noted however that the cost of congestion reported by the Energy Users Association of Australia (EUAA), based on analysis by Marsden Jacob Associates and earlier analysis by Port Jackson Partners for the Business Council of Australia (Port Jackson Partners 2005) are not measures of the economic cost of transmission congestion.

In each case, simple estimates are made of the likely national spot price for electricity had there been no transmission constraints in any period. The implied reduction in price for all electricity sold in higher priced regions is then calculated and reported as the cost of congestion. Putting aside the approximations used in these calculations and the impracticality of a ‘no-constraint’ case, this calculation represents what in economic terms would be called the ‘congestion rents’. It does not represent the underlying cost of congestion to the market as a whole.

The most robust analysis of the cost of congestion conducted to date has been performed by the AER, with the close collaboration of NEMMCO. The AER analysis extracts the Marginal Cost of Congestion (MCC) from actual dispatch and also takes the market dispatch engine and re-runs the dispatch process after relaxing all the constraints to calculate a “Total Cost of Congestion” (TCC).

The MCC measure is the more appropriate measure for identifying the impact of constraints on market outcomes, but is flawed because of the lack of intra-regional congestion pricing. The TCC provides a consistent measure of the indicated total impact of congestion but will be flawed in any case where dispatch on an un-congested basis is significantly different from the actual market dispatch. For 2003-04 and 2004-05, the TCC indicated a total cost of congestion of $36 million and $45 million respectively. This TCC measure represents the savings in supply costs, predominantly fuel costs, if lower priced generators were not constrained.

It is noted that these measures are based on data from the market dispatch mechanism and therefore reflect:

» the current formulation of constraints in the market;

» generator bidding in the current market setting and with the network configuration at the time;

» short term behaviour; and
Box 5: The complexity of inter-regional constraints

The Queensland and New South Wales Interconnector (QNI) was designed with a nominal capability of 1000 MW south from Queensland to New South Wales and 600 MW north. It began operation on 18 February 2001 and the importance of a range of other constraints in northern New South Wales and southern Queensland became apparent soon after. The capacity of the interconnector was limited to less than half these figures for a period and it was not until 2005 that QNI provided southbound capacity of 950MW and northbound capacity of 700MW. Testing and improvements to control systems now give QNI a nominal rating of 1078 MW south provided NEMMCO’s on-line stability monitoring equipment is in service.

The rating remains dependent upon loadings on a number of critical elements in the transmission network even when all plant is in service. The rating also depends upon the commitment and dispatch of certain generating units. NEMMCO’s “Interconnector quarterly performance December 2005 – February 2006” published in Version Number 1.1 March 2006 provides a snapshot of the transfer capability of the link during the critical summer period. This shows how volatile interconnector limits can be. When compared to the actual “interconnector” line limits, this also highlights how a number of factors and the whole surrounding network contribute to setting transfer capabilities. There is further discussion of these issues in chapter 7.

13 MT PASA vs actual limit for QNI

The history of QNI also indicates flaws in the national coordination of planning at the time of its development. Better planning in this case may have led to a better sequence of development and should certainly have provided better information to market participants.

Although the recent ANTS analysis indicates that a proposed upgrade to the QNI itself appears to be of marginal value, it forecasts a significant cost arising from all constraints in aggregate over the plan period. Network planning on a national basis which integrates the development of the total network to deliver both reliability to customers and to maximise the net benefits it brings to the market, is expected to deliver real benefits over time.
impacts and behaviour on the supply side and hence excludes some (small) demand side inefficiencies.

ERIG notes that although this measure of the cost of congestion is imperfect, it is considered that it is the most reliable indication of the annual economic costs of congestion across all transmission constraints within the NEM currently available. Regardless of the overall cost of inter-regional congestion, the fact that it is priced has enabled the risk of reasonably predictable transmission congestion to be hedged in the financial market, including through instruments such as the settlement residue units. Settlement residues are discussed further in chapter 7.

Generators are, however, sensitive to the cost of managing the risk of transmission congestion, particularly where that congestion is unpredictable and impacts on their ability to deliver physical volume and efficiently manage commercial risk across NEM regions. Generators face volume and price risk where they trade against a Regional Reference Node (RRN) outside their region. This issue is not entirely divorced from intra-regional congestion, as intra-regional congestion does impact on the capacity of interconnection.

It is the uncertainty of inter-regional congestion that has the largest impact on commercial and competitive outcomes in the national market. This uncertainty is currently priced as a discount on the value of settlement residue units. TNSP operational and investment decisions have significant short and long-term impacts on the competitive sector.

In the short term, maintenance scheduling and other system operation decisions have the potential to impose significant commercial risks on participants, particularly where the effect of those network decisions change the volume and price risks faced by a market participant. In the medium to longer term, the nature and timing of any investment by TNSPs can also impose significant commercial risks on participants.

The cost of financial risk management for inter-regional trade is discussed further in the financial markets chapter. ERIG notes that firming up settlement residues requires a reduction of the uncertainty in the availability of physical transmission capacity.

**ERIG findings**

ERIG is of the view that the lack of alignment between the drivers on transmission operation and the commercial needs of transmission users has increased the cost of inter-regional trade and has led to an inefficient under-utilisation of transmission assets.
Network operation and investment

Under the current arrangements TNSPs do not have obligations and accountabilities to undertake network augmentations premised on those augmentations delivering net market benefits.

International Power and Loy Yang Marketing Management Company (LYMMCO), in their submissions to the ERIG Issues Paper, argued that a key deficiency in the NEM trading arrangements is that the transmission service providers are essentially isolated from market signals and as a consequence do not have appropriate performance measures which are aligned to market outcomes, leading to inefficiencies in NEM operations and network investment.

Delta Electricity and NEMMCO, amongst others, supported this concern in their own submissions to the ERIG Issues Paper, noting that inadequate performance incentives on TNSPs, to closely align planned outages with market needs, have the potential to limit the effectiveness of the role of transmission.

Whilst ERIG broadly agrees with this concern, ERIG also notes that, as discussed in Operational and investment drivers on the contestable sector, generator bidding behaviour also impacts on the ability of TNSPs to deliver transmission services.

That said, the regulatory regime and the broader reliability and other accountabilities imposed on TNSPs influence network operation and investment decision making. The incentives built into the regulatory regime can impact on the way a transmission business makes existing transmission network capacity available, how it invests at the margin to ensure system security and reliability of the network and on the timing, size and location of investments undertaken more broadly.

Due to the inter-related nature of issues arising from the broad points outlined above, the following section breaks the discussion into three key areas:

» the Regulatory Test;
» transmission planning criteria; and
» incentives imposed through operational and capital expenditure arrangements.

The Regulatory Test

The connection between the Regulatory Test and the economic regulatory framework is widely misunderstood. Firecone’s advice to ERIG suggests that the relationship between the Regulatory Test and the determination of the Regulatory Asset Base (RAB) has been problematic since market start.

Following the Network and Distributed Resources (NDR) Code changes in March 2002, there is no direct link between the Regulatory Test and the economic regulatory regime. Whilst the AEMC changes to the Rules include a provision requiring the TNSP to identify any forecast capital expenditure that is for a reliability augmentation or has passed the Regulatory Test, the decision making criteria to be applied by the AER do not require that projects must have passed the Regulatory Test to be included in the forecast.
This appears sensible as most projects have not been subjected to the Regulatory Test at the time the ex-ante revenue cap is being determined and will therefore form the minority of the overall expenditure forecast. It is further noted that there is provision for a contingent projects allowance, which can only be accessed when a project within the contingent allowance is shown to meet the Regulatory Test during a regulatory period.

The only area in the past where there has been a direct relationship between the outcomes of the Regulatory Test and the calculation of the RAB is in respect of interconnector investments. Prior to the NDR Code changes, interconnector assets could only be added to the RAB if they satisfied the market benefits limb of the test. However, even here it remained unclear whether the amount to be added to the RAB was the amount specified in the Regulatory Test or the actual cost of the project. There has never been a link between the Regulatory Test and the RAB for other network investments i.e. network investment within a region.

The ACCC’s adoption of an ex-ante approach to revenue determination, as part of its Statement of Regulatory Principles (SRP) in December 2004, further weakened any potential relationship between the Regulatory Test and the RAB. Fierce notes that under the AEMC’s draft revenue cap regulation Rules, the depreciated value of all expenditure, regardless of whether it has or has not passed the Regulatory Test (or indeed had the test applied to it), will be added to the RAB at the start of the next regulatory control period.

While ERIG considers that there is only a tenuous link between the regulatory regime and the current Regulatory Test, ETNOF, Powerlink and TransGrid in their responses to ERIG’s Discussion Papers, suggested that the link is anything but tenuous.

Powerlink suggested that the Regulatory Test is “central” to the AER’s decision making. Further, TransGrid argued that the new AEMC Rules:

“expressly require the provision regulatory test assessments as a pre-requisite for specific projects being accepted by the AER as part of the capital expenditure targets for revenue setting purposes.”

Box 6 below analyses these claims with respect to the setting of the ex-ante capital expenditure forecast and the rolling forward of the RAB, as the two key areas of the regulatory framework in which the Regulatory Test may have an impact.
Box 6: The link between the Regulatory Regime and Regulatory Test

Setting the ex-ante capital expenditure forecast

The AEMC Rules require the AER to accept a forecast of required capital expenditure of a TNSP if the AER is satisfied (see below) that the total of the forecast capital expenditure for the regulatory period reasonably reflects:

- the efficient costs of achieving the capital expenditure objectives;
- the costs that a prudent operator in the circumstances of the relevant TNSP would require to achieve the capital expenditure objectives; and
- a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

In determining whether or not the AER is satisfied that the forecast meets the above criteria, the AER must have regard to ten capital expenditure factors. None of these factors refer to the Regulatory Test. There is no requirement that a project must have passed the Regulatory Test to be included (either deterministically or probabilistically) in the ex-ante forecast.¹

It is a requirement on the TNSP that its revenue proposal identify any proposed expenditure that is for either a reliability augmentation or an option that has already satisfied the Regulatory Test. This requirement relates to the information that must be provided to the regulator in a revenue proposal, but is not a criterion for the determination of the capital expenditure forecast.

This requirement makes logical sense as, if there are projects that are to be constructed during the regulatory control period that have passed the Regulatory Test, the regulator and its consultants can readily make the assessment that there is an economic justification for including this project in the overall forecast.

Powerlink will have had to supply the AER with an economic justification for why projects should be included in the calculation of the ex-ante revenue cap and in the future TNSPs will have to do so in accordance with guidelines published by the AER. The process to set the ex-ante price cap is vital to the current regulatory regime but this should not be confused with the Regulatory Test process undertaken immediately prior to project commitment. It is true that a TNSP has to convince the regulator that there is a sound economic justification for the inclusion of projects in the revenue cap, but the Regulatory Test does not, as Powerlink has suggested, have a “central” role in this.

Setting the opening Regulatory Asset Base

Under the previous regulatory arrangements, the regulator undertook a review of capital expenditure in the previous period prior to setting the opening RAB for the next period. The arrangements allowed the AER to deduct any capital expenditure identified in the ex-post review to be inefficient from the closing asset base from the previous regulatory period.

¹ There is another minor reference to the regulatory test in chapter 6A– the regulatory test definition of “committed project” is used for the purposes of transitioning existing transmission assets to the chapter 6A framework.
The more recent Statement of Regulatory Principles removed the ex-post review process and the AEMC’s new transmission revenue rule confirms this. The Rules now make no reference to projects having to pass the Regulatory Test to be included in the rolled-forward RAB of existing TNSPs.

Accordingly, the process of ex-post reviews is not relevant to ERIG’s deliberations. It is true that the roll-forward of Powerlink’s RAB is being conducted with an ex-post review, but this is because its original revenue cap was set under an earlier version of the regulatory framework.

The AEMC’s new transmission revenue rule

The AEMC transmission revenue rule determination re-affirms the ex-ante framework. Under this framework the RAB must be rolled forward by increasing the closing RAB for “all capital expenditure incurred during the previous control period”.

The arguments put forward by the TNSPs, that the new AEMC Rules require the provision of Regulatory Test assessments as part of the determination of capital expenditure targets, are most likely based on the AEMC’s draft revenue Rule which explicitly required the AER to accept the forecast capital expenditure if that expenditure satisfied the regulatory test (Draft 6A.6.7 (b) (iii). It should be understood that this provision was not included in the final revenue Rule.

Conclusion

This analysis has focussed on the two key areas of the regulatory regime where the Regulatory Test may play a role. ERIG remains of the view that there is, at best, a tenuous link between the Regulatory Test and the regulatory regime.

It should be noted that ERIG has not sought to criticise the economic principles embodied in the Test. Rather, ERIG has been concerned to understand the role of the Regulatory Test in the emerging regulatory regime.

Given this tenuous link between the Regulatory Test and regulatory revenue determination arrangements, it is unclear why the Test has continued to be an issue of such contention and focus of development within a regulatory context. ERIG notes the wide range of concerns raised in relation to the Regulatory Test, including the perception that the test is too prescriptive and acts as a barrier to new investment rather than to encourage efficient investments.

Debate over the Regulatory Test has included its objective; the definition of projects, benefits and costs; and its scope. Despite this debate, its usefulness in driving efficient transmission investment outcomes would only appear to extend to its public consultation, information provision and transparency role.
ERIG findings

ERIG suggests that the importance of the Regulatory Test as a public consultation mechanism should not be understated. However even in this role the usefulness of the test is currently limited by the extent to which information is available to analyse its application and the uncertainty created where the test is applied by the proponent of the transmission investment project.

Under the current regulatory environment it is unlikely that the tenuous link between the Regulatory Test and the economic regulatory arrangements can be strengthened.

The two limbs of the Regulatory Test

ERIG notes that over 90 per cent of projects submitted to the Regulatory Test have been submitted as reliability augmentations. ERIG suggests that many of these projects had both market and reliability benefits. However, due to the least cost assessment nature of the reliability limb, alternative options which have broader market benefits would not be deemed to have passed the Test if they are not least cost, regardless of any benefits that may accrue to the national market. In its report prepared for ERIG, CRA argues that:

“The Regulatory test is…structured in such a way as to create essentially arbitrary distinctions between projects yielding “market” versus “reliability benefits”, private versus public benefits, and forces projects to be assessed entirely under one heading or another. In practice projects may yield benefits in more than one category” (CRA 2006).

CRA notes that, as an important example, “the reliability-related benefits of inter-regional proposals are therefore likely to be undervalued or ignored”. This argues for integration of the benefits behind both limbs of the test.

In its submissions to ERIG, TRUenergy cautions, however, that generation is necessarily impacted by many “reliability” augmentations, and therefore the range of non-transparent and unpredictable (transmission) planning criteria create uncertainties and doubt for generator investors. This is particularly the case where the planner is not independent of asset ownership and/or may not be seen as fully independent from other parts of the industry. TRUenergy considers that the non-transparent and difficult to dispute nature of the reliability limb then provides unreasonable protection to such investments from regulatory scrutiny.

ERIG findings

ERIG agrees with concerns that the economic benefits from integrating the two limbs of the Regulatory Test in any future investment decision making process may be eroded by poorly specified and inconsistent reliability standards and planning criteria.

The Energy Retailers Association of Australia (ERAA), in its submission to ERIG’s Discussion Papers, noted that failing to increase the specificity of the planning criteria, and in particular those criteria relating to reliability, would have significant ramifications for any reform to the Regulatory Test.
The ERAA has suggested that the current market benefit limb is a pure economic benefit test. The ERAA notes that, conversely, the reliability limb of the Regulatory Test is a source of distortion, with different planning standards applying in different jurisdictions, all of which drive fundamentally different outcomes. As a result, the ERAA is concerned that if the two limbs of the Regulatory Test were merged, without any remedial action being taken to fix the distortions created by the reliability limb, the pure economic test of the market benefit limb would also become distortionary. ERIG agrees with this concern. The issue is considered further under A Consistent National Framework for Reliability Standards.

Transmission planning criteria

The transmission planning standards included in the Rules are, by design, flexible and allow for compliance of very different standards of supply. This has left them open to different interpretations. Firecone illustrates this by outlining the range of interpretations set out in submissions responding to Powerlink’s proposal to construct a new large network asset to address emerging issues in the Darling Downs area in Queensland (Firecone 2006b).

Many submissions to the ERIG Issues and Discussion Papers raised concerns with jurisdictionally focussed reliability and planning criteria. In particular, the ERAA noted that “there are several jurisdictional planning standards that drive most transmission investment” (ERAA 2006). Gallaugher and Associates noted that “Network planning methodologies and investment criteria vary considerably from state to state” (Gallagher and Associates 2006). International Power and LYMMCO suggested that to maximise economic efficiency, all planners should use identical Regulatory Test and planning criteria.

The ERAA argued that to achieve a genuinely national electricity market, the reliability standards should be harmonised across all jurisdictions and their specificity increased significantly. Both Gallaugher and Associates and ERAA noted that a probabilistic approach is more consistent with the criteria used by private investors in generation.

ERIG agrees with the Gallaugher and Associates view that:

“these differences have the potential to lead to substantially different levels of regulated network service being provided by the respective transmission companies even though they are both ostensibly operating under a common network access regime” (Gallagher and Associates 2006).

ERIG accepts the advice of Firecone in its report to ERIG on transmission, that the interpretation of planning criteria involves consideration of numerous factors that interact in uncertain ways. Considerable judgement is often required to decide whether the network is compliant with criteria, and what type of investment should be made in order to ensure that it will be compliant in the future. With the same criteria, different planners could come to significantly different conclusions. Equally, with different criteria, similar investment decisions are nevertheless possible.

ERIG findings

ERIG is of the view that there are significant efficiency and investor certainty implications associated with the current transmission planning criteria. The lack of specificity in the current criteria and the diversity of approaches across jurisdictions may create uncertainty for investors in generation.
Incentives imposed through operational and capital expenditure arrangements

ERIG has considered two issues with respect to incentives. Firstly, ERIG has explored the balance between operational expenditure and capital expenditure incentives and secondly, the incentive properties themselves and their ability to drive efficient outcomes.

Balance between operating and capital expenditure incentives

Under the current approach a TNSP receives an ex-ante allowance for capital and operational expenditure. The current regime therefore provides, albeit in weak form, an incentive to minimise expenditure within the regulatory period. New network augmentations that may be required throughout this period must be subject to a Regulatory Test, subject to a minimum threshold.

Whilst the Regulatory Test is meant to provide a framework for the consideration of network and non-network options alike, the current regime may not be achieving this objective. ERIG considers that this is primarily due to the fact that TNSPs are granted an allowance for a return on capital in addition to a return of capital (including allowances for depreciation) in the revenue building block calculation. However, operational expenditures are treated on a simple ‘cost back’ basis. This gives the TNSP a prima facie incentive to seek a network solution ahead of an alternative.

This concern has been noted by Energy Response, where it suggests that the current “planning methodologies, economic assessment techniques, and qualitative assessments of the network versus non-network solutions are all inherently biased in favour of investing more in traditional network investments at the expense of non-network solutions” (Energy Response 2006).

ERIG findings

ERIG considers that this raises a need to redress the balance of the incentive regime and to ensure that the power system as a whole is considered without a technology bias.

Operating expenditure incentives

A TNSP receives an ex-ante allowance for operational expenditure and, under proposed changes, can retain a proportion of any savings in subsequent regulatory periods. This provides an incentive to minimise costs but not to maximise the value of services provided by the regulated revenue. The current regulatory regime does not appropriately incentivise TNSPs to institute innovative practices that may increase the capability of their network for short periods of time to the benefit of the competitive market without jeopardising reliability and system security objectives.

Origin Energy notes, in its submission to the ERIG Issues Paper, that the current incentives for transmission companies centre on the availability of a number of different transmission elements and on the duration and frequency of outages. However, Origin Energy is of the view that no real link is made between transmission performance and its impact on spot market outcomes.
ERIG considers that the current service standard incentive regime is an aggregated and simplistic measure of asset availability throughout a financial year. This regime does not have the ability to determine whether the network was available at times when the competitive market valued it most.

However, ERIG notes that the final chapter 6 rule requires that the AER develop a service standard incentive scheme for each TNSP to:

“provide greater reliability of the transmission system that is owned, controlled or operated by it at all times when transmission network users place greatest value on the reliability of that transmission system”; and

“improve and maintain the reliability of those elements of the transmission system that are most important to determining spot prices” (AEMC 2006).

ERIG considers that this is a step forward from the more technical, circuit availability style incentive regime included in the SRP. ERIG also notes the increase of the maximum power of the incentive from +/- 1 per cent of the allowed annual revenue to +/- 5 per cent.

In particular, ERIG is of the view that there is benefit in extending the service standard incentive as required in the Rules to further support the needs of the competitive market. For example, the regime could be extended to include incentives for dynamic line ratings, which would encourage TNSPs to run their network harder in appropriate weather conditions to facilitate the more efficient dispatch of the competitive market. The changes to the NER arising from the AEMC’s transmission pricing review require an initial scheme to be in place by September 2007.

An incentive based regime would be better supported by arrangements that were based on payment for service levels rather than the current bias toward payment for assets.

ERIG findings

ERIG recognises that the continued development of market-based incentives in the regulatory regime for the supply of transmission services is primarily the responsibility of AER.

ERIG considers that an important step in minimising the operational divergence between the competitive and regulated sectors requires linking the AEMC congestion management regime, the AER service standards incentive work and transmission planning arrangements.

Capital expenditure incentives

A TNSP receives an ex-ante allowance for capital expenditure and, under proposed changes, any capital expenditure actually made during the regulatory period is rolled into the opening regulated asset base for subsequent periods. This provides only a weak incentive to minimise capital spending and no incentive to drive efficient investment across the network costs but not to maximise the value of services provided by the regulated revenue.

The principle drivers for investment in transmission, aside from asset replacement, are the jurisdictionally based reliability requirements. TNSPs understand that they will be held
accountable for maintaining reliable supply and can be expected to invest as necessary to meet these standards. TNSPs consistently refer to the importance of these obligations in their investment decision making.

On the other hand, there is no obligation on TNSPs to undertake investment to deliver net market benefits either within their state or nationally. The reliability requirements are set and applied differently from state to state and in some states might be stretched to justify a wider range of options within the state.

These obligations do not apply across state boundaries and hence incentives to drive interstate investment do not exist. The nature of the two limbs of the Regulatory Test can also drive distortions which might lead to inefficient investment outcomes. In addition, as previously noted, the Regulatory Test prohibits consideration of investment options which seek to deliver both reliability and market benefits removing a further option to optimise capital expenditure.

For both inter and intra-regional investment, there is no accountability for a particular project to deliver its design capability, even where that capability has been used in the Regulatory Test. Similarly the incentives to minimise costs and maximise the value delivered are weak as any expenditure becomes part of the regulated asset base in perpetuity.

**ERIG findings**

ERIG considers market-based incentives should allocate accountability for service delivery linked to transmission investment design capability.

Capital efficiency in transmission investment is even more difficult to assess on a standalone basis. Even the best measure of transmission transfer capacity per dollar of investment is meaningless if a more efficient pattern of investment in generation would have removed the need for that capacity. The need to optimise both transmission and generation investment is discussed below.

**National focus and strategic network planning**

The NEM has evolved from a set of state based grids to an interconnected NEM-wide network. The level of interconnection has increased significantly between the state grids over the past five years. Firecone in its advice to ERIG noted that as a proportion of peak demand and installed capacity, the commissioning of QNI, Murraylink, DirectLink, SNOVIC and BassLink has delivered a more deeply interconnected power system.

In an interconnected alternating current AC electricity grid, additions and subtractions of generation or network capacity at any point within the system affect conditions in other parts of the network. As a result, it is not possible to plan and develop subsections of the system in isolation. Efficient system wide development requires planning to be co-ordinated across generation, transmission and load. The increased level of interconnection in the NEM has elevated the need for NEM wide co-ordination for the efficient development of the entire transmission system and energy market.

A number of parties and ERIG’s consultant, CRA, acknowledged the benefits of the ANTS process considering that it has improved the information available to the market. Many noted that further improvements can be made. CRA notes though that the links to the regulatory regime and the planning and development of the national power system is
problematic and they recommend instituting "an annual, nationally focussed consultation/planning cycle over and above the requirement on NEMMCO to produce the ANTS." They also argue for establishing a "clear focus on long-term strategic developments" (CRA 2006).

**Investor certainty**

ERIG considers that an important element of delivering a fully national and efficient grid is ensuring investor certainty in the competitive sector is not adversely affected by arrangements in the regulated sector.

ERIG notes that the current arrangements require the TNSP to apply the Regulatory Test to investment proposals and develop and publish consultation documents on those investment proposals. The primary transmission planning document in the NEM is the Annual Planning Report produced by each TNSP.

As noted in the discussion on the Regulatory Test (above), TRUenergy considers that commercial certainty is undermined when the transmission planner is not independent of asset ownership and/or may not be seen as fully independent (TRUenergy 2006).

Snowy Hydro is of the opinion that separation of the transmission planning function from transmission asset ownership and control would deliver market benefits through increased quality and transparency of the information that forms the basis on which investors make investment decisions. In its submission to ERIG, Snowy Hydro expressed the view that information asymmetry between TNSPs and the rest of the market exacerbates this risk.

ERIG agrees that there is a conflict of interest issue where the proponent of a project is also responsible for project assessment and the application of the Regulatory Test. This is compounded where the planning criteria applied to the project are open to a variety of interpretations, the data to analyse the project is not fully available to the market and there is limited specialist expertise to make an independent assessment.

**ERIG findings**

ERIG considers that this issue is significant given the role the Regulatory Test plays as a consultation and information tool. This is because the consultation process and information provision requirements are an important link between the market and the regulated sector. Any perception that a transmission investment proposal is being made on grounds other than economic efficiency increases the risk faced by investors in the commercial sector.

**Government ownership**

ERIG considers that there are sovereign risk issues where governments are shareholders in both transmission and generation assets. In the NEM, this is the case in New South Wales, Queensland and Tasmania. The extent of cross-ownership is shown in Figure 14.

Firecone, in its advice to ERIG, noted that this cross-ownership brings the risk that transmission investment decisions which could, or could be seen to, favour generation owned by the relevant state government. ERIG agrees with Firecone that, regardless of whether it does so or not, it will result in a perception of a conflict of interest in the TNSP’s decision-making.
ERIG has discussed government ownership in chapter 5. However, several transmission specific points are worth reiterating.

ERIG notes that many submissions identified government ownership of both transmission and generation as a significant sovereign risk issue. These concerns related to the possible pursuit of policy rather than transparent commercial agendas, or the possible conflict arising from transmission and generation having the same owner.

The MCE is currently progressing legislative amendments to structurally separate ownership of generation and transmission at a participant and shareholder level. ERIG understands that while these provisions will apply to government owned entities, they are not proposed to apply to ownership by the crown.

ERIG findings

ERIG agrees with the majority of submissions and the conclusion of Firecone that the significant cross-ownership of generation and transmission creates the perception by private investors of a conflict of interest. Regulatory constraints, either through the imposition of a revenue cap or the application of the Regulatory Test, are not effective in reducing that perception.

Separation of asset ownership and the investment decision

It has been suggested that the current arrangements in jurisdictions where the investment decision is made by the owner of the asset do not provide the appropriate incentives on the owner to invest in a timely and efficient manner.
TRUenergy in its submissions to ERIG notes that the issue of national co-ordination may be further weakened where the transmission planner is not independent of asset ownership and/or may not be seen as fully independent from other parts of the industry.

International Power Australia and LYMMCO in their submissions to ERIG consider it essential that the governance arrangements are such that the transmission planning function is separate and independent from asset ownership to avoid conflicts of interest and to facilitate the competitive provision of services and assets wherever possible.

Conversely, there is an argument that uncoupling of responsibility for making decisions about the timing and nature of transmission development from grid ownership diminishes accountability over investment decisions and will increase the risk and cost to customers of poor investment decisions.

ERIG considers that the case put by network owners has merit but depends upon the extent to which the regulatory regime holds owners accountable for efficient, national investment and the delivery of efficient services. The arguments in favour of independent decision making are strengthened in the absence of such accountability. The governance options for the implementation of a national planning function are discussed below and consider the potential advantages and disadvantages of uncoupling of responsibility, and therefore accountability, for investment decision making from asset ownership.

National focus

ERIG is of the view that transmission planning and decision-making has become more regionalised since the start of the NEM. Whilst collaboration has occurred on individual interconnector projects, comprehensive strategic national planning has not developed.

The NDR code changes of March 2002 removed any formal obligation on any entity to plan and develop interconnectors. Additionally, TNSPs and Jurisdictional Planning Bodies have no obligation to maintain or increase transfer capacity across the transmission system other than to meet local reliability obligations. This lack of a national focus was noted by NEMMCO which suggested that once an interconnector is established there is little obligation on any party to maintain that transfer capability to a level that delivers maximum benefits to the market, or to the level assumed in the Regulatory Test.

Firecone notes that, at the time of the NDR code changes, it was recognised that reliance on completely regionalised planning may fail to deliver efficient expansion of the integrated transmission network across the NEM as a whole. ERIG notes that a fundamental component of the policy shift introduced by the NDR code changes was the introduction of information provision mechanisms to facilitate national co-ordination. Information provision is discussed further below. This regime, which has developed over time, provides no one body with responsibility for national coordination of the network development. In its advice to ERIG, Firecone states:

“*It appears unlikely that the current framework is achieving efficient investment, taking account of costs and benefits across the NEM as a whole. Many investments are likely to have impacts outside the region concerned. However, measures to facilitate co-ordination appear much weaker than measures which promote regional decision making*” (Firecone 2006).
Ergon Energy, in its capacity as a distributor, suggested that the “jurisdiction by jurisdiction planning approach does not result in region centric planning nor limit the national approach”. However it agreed that “joint planning between transmission authorities could achieve inter-regional planning outcomes that are optimal” (Ergon Energy 2006).

Powerlink, ETNOF and Transgrid in submissions to ERIG’s Discussion Papers strenuously argued that hardly any transmission investments have impacts outside the region concerned. The submissions stated that only one in forty proposals over the past three years has had an impact outside the region concerned.

ERIG considers that assessing whether or not there has been an inter-regional or interconnector impact depends on the criteria used in that assessment process. To elaborate, an assessment based on thermal limit implications for inter-regional transmission elements are unlikely to be affected to the same level as transfer stability. The reason for the apparent mis-alignment of views can be understood by examining a recent example of a “within region” investment. TransGrid’s proposed “Development of supply to the Newcastle-Sydney-Wollongong Area” sets out the issue in more detail.

**Box 7: Need for national planning - TransGrid’s proposed development of supply to the Newcastle-Sydney-Wollongong Area**

This project was assessed under the reliability limb of the Regulatory Test and the documentation states that this project “does not have a material inter-network impact”. TransGrid’s view that the project does not have an inter-network impact is based on a technical assessment of the impact of the project on the power transfer capability of the lines connecting the TransGrid network to other networks, or its impact within other networks. The view reflected is one usually taken by TNSPs and arguably reflects the current Rules.

A plan of the national network showing the section from Sydney to central Queensland is provided in figure 15 below. The proposed augmentation arising from this assessment plans to upgrade the existing lines from Bayswater to Marulan to Mt Piper from 330 kV to 500 kV. This is a large project (NPV estimated at $320 M) and involves some other related upgrading and changes to the connection of two generating units at Bayswater.

The view that this has no inter-network impact was questioned in a submission by Snowy Hydro and TransGrid expanded their reasoning for taking such a view. The following illustration highlights that the proposed augmentation of these lines, while it is unlikely to significantly change the transfer limits on the Armidale to Braemar line or lines within another state, does have potentially significant impacts on trading in the national market and the efficient use of the national network. These potential impacts, both positive and negative, warrant broader national consideration if the design of the project is to be optimised.

An ‘interconnector’ as defined in the NEM Rules is the “notional” interconnector between two regional reference nodes each of which seek to represent the location of the major large customer load within a region. The regional reference nodes in this example are as follows:
the Queensland regional reference node is South Pine 275kV bus;

the New South Wales regional reference node is Sydney West 330 kV bus.

These have been highlighted on the following network plan in the simplified expression of the Primary QNI South Constraint, taken from the 2006 ANTS, presented in figure 15.

The interconnector can be seen in this context to be much more complex than the Armidale to Braemar line which is often considered to be ‘QNI’. There are a number of lines which could be seen to directly transfer power between South Pine and Sydney West. Secure power transfer ratings are generally defined by the safe transfer limits following a single credible contingency and hence any lines or transmission plant between these nodes can be expected to have an impact on transfers either all the time or at times with prior outages. The potential for power transfer ratings to be based on transient stability or oscillatory stability widens the range of potential elements involved. In fact, the potential transfer capacity between these two nodes at various times could be set by literally dozens of different factors.

More broadly, market dispatch is seeking to determine the optimum, security constrained mix of generation to meet the load with regard to the capability of the real network rather than the ‘notional interconnector’. In this context, market operations are seeking to dispatch generators (shown as green boxes on the plan) to customer load; for example at the New South Wales reference node. In this context, even more lines over a wide area of Queensland and New South Wales could impinge on trading across the network to the Sydney market and any of these could have a significant impact on market price setting. Regional loads can and do affect the net transfer capability available as does the need to maintain voltages and other power quality parameters within acceptable bounds even following any credible contingency.

In this example, only the transfers from generators in New South Wales and Queensland can be seen competing for supply to the Sydney West node. The same arguments would apply for generators located in the south of New South Wales and the Snowy and southern regions of the market if we reproduced that section of the national grid. This is the reason for Snowy Hydro’s concern, as expressed in its submission, that the proposed augmentation will have broader market impacts.

This single project is an example where the assessment of this project as a Reliability augmentation, with no material impact on other networks, is too narrow and technical an approach. The project can be expected to have a significant impact on national market operation and dispatch, on risks and rewards to traders in the market and on efficient use of the national network. These impacts could even be very significant under certain operating conditions. It is also a clear case where the assessment on a project basis without the context of a long term plan is also of concern.
15 Factors that limit southward flows on QNI$^{a,b,c,d}$

\[
604.69 \\
-0.0954^{*}NSW1 - 0.0378^{*}VIC1 - 0.1235^{*}QLD1 + 0.2573^{*}(CENTRL+NTHQLD) \\
+ 0.1287^{*}(SNWY1) \\
-0.1958^{*}Bayswtr + 24.95^{*}Bayswtr + 103.36^{*}Bayswtr + 68.77^{*}Wallerawng + 103.48^{*}ValesPt \\
+ 60.43^{*}Munnrh + 103.48^{*}(Eraring1+2) + 103.48^{*} (Eraring3+4) -0.1927^{*}Liddell \\
+ 67.52^{*}Liddell + 103.35^{*}MtPiper + 25.21^{*}Redbank + 8.42^{*}SHGen1 + 8.42^{*}SHGen2 \\
+ 16.71^{*}SHGen3 + 16.71^{*}SHGen4 + 10.84^{*}Bhwng + 8.88^{*}HunterVly + 10.42^{*}Sithe1 \\
+ 10.42^{*}Sithe2 + 10.42^{*}Sithe3 + 10.42^{*}Sithe4 \\
+ 3.2^{*}Guthega + 7.61^{*}Tumut1 + 6.44^{*}Tumut2 + 25.68^{*}Tumut3 + 8.64^{*}Murray1 \\
+ 12.53^{*}Murray2 \\
+ 8.79^{*}Roma + 0.1359^{*}Roma + 2.5^{*}Barcaldn + 0.1359^{*}TarongOnly + 0.1359^{*}Oakey \\
+ 16.53^{*}Oakey + 6.20^{*}SwbnkB + 56.70^{*}Swan_E + 0.1359^{*}SwbnkBE \\
+ 32.04^{*}Wivenhoe+0.1359^{*}Wivenhoe + 0.2573^{*}NQ_NEntry + 0.2573^{*}CQ_NEntry \\
+ 0.1359^{*}(SEQ_NEntry) + 0.1359^{*}(SWQ_NEntry) - 0.1958^{*}(NGen_NEntry) + 0.1359^{*}(Mlmrn) \\
+ 0.1359^{*}(Kogan+Wambo) + 20.04^{*}(Mlmrn) \\
- 0.0954^{*}(NSW->QLD) - 0.0378^{*}(VIC->SA) - 0.0283^{*}(VIC->SNWY) - 0.2241^{*}(SNWY->NSW) \\
- 0.0954^{*}(NSW->QLD(DL)) \\
a: This is a simplified expression of Primary QNI South Constraint under the assumption that there are no network outages, b: Positive coefficients reduce flows, negative coefficients increase flows, c: The larger the coefficient, the greater is the impact on southward flows, d: Assumes all network elements are in service and Millmerran is generating
ETNOF, in its submission to the ERIG Issues Paper, outlines the complexity of establishing secure interconnector transfer limits and how "limits depend not on the capability of a single element (eg an interconnector line) but on the interactions of numerous elements in the whole system (eg on which generators are operating, at what output, what the flows are on other interconnectors etc)." It is in this context that the impact of a proposed augmentation within a region will often have an impact on constraints in the market and hence market and pricing outcomes. The preceding box includes just one equation applying to flows on QNI as an example included in ETNOF’s submission.

In its submissions to ERIG, Origin claims transmission companies have substantial informational, knowledge and experiential advantages in relation to where and when transmission investment is needed. They are best placed to have the responsibility for planning investment within their jurisdictions. Origin is also comforted by the extensive information disclosure and consultation obligations in the Rules, including requirements for TNSPs to consider the impact of investments in a national context and to co-operate on interconnector proposals between regions.

On the other hand, the submissions of International Power and LYMMCO suggested that network investment should be allocated NEM-wide according to greatest economic benefit and that all augmentations should be sourced in a contestable manner.

CRA advice to ERIG notes that, with respect to the development of inter-regional links and improving coordination between inter-regional investment decisions and intra-regional networks, jurisdictional obligations place strong incentives on TNSPs to meet reliability provisions within states (and as a result also within regions as region boundaries are still closely aligned with state borders). However, the incentive to pursue inter-regional augmentations is significantly less.

CRA goes further, suggesting that each of the TNSPs maintain their own planning arrangements and although they may decide to cooperate, not all augmentations will be mutually beneficial to adjoining TNSPs, nor will all augmentations that provide market benefits necessarily be the most beneficial to the proponent TNSP. There are examples where, prima facie, there has been a mismatch between inter- and intra-jurisdictional developments. Assessments of the materiality of these impacts depend on the consequential decisions of a presumptive generation investment that becomes economic or not economic because of a different transmission development path.

ERIG also notes that the sequential nature of revenue cap determinations limits the development of nationally co-ordinated investment plans. This is because the regulator and the individual TNSP are conducting determinations in isolation and in the absence of certainty over the investment proposals of other TNSPs, thereby minimising the ability of each to identify mutually supporting projects. Furthermore, the current sequential arrangements limit the regulator’s ability to compare costs and assess a nationally efficient level of expenditure.
ERIG finding

On balance, ERIG concurs with the views of CRA and Firecone that transmission planners with reliability obligations within a defined geographic region do not currently face incentives to appropriately consider market conditions in the broader NEM. This is particularly the case where the planner in one region receives little or no benefit from adopting network solutions with positive benefits for the system as a whole.

ERIG notes that factors contributing to regionalised planning include:

» planning and delivery of transmission services are geographically fragmented and there is a lack of accountability for national grid planning, development and operation;

» state government ownership of TNSPs may dilute a national focus, particularly where governments also own generation assets;

» network pricing arrangements do not recognise and charge interstate beneficiaries of proposed augmentations;

» the specification of different network planning standards by state governments or state institutions across the electricity system;

» the form and application of the Regulatory Test which treats network planning and development to meet customer reliability standards as separate from planning to augment the network to deliver market benefits and which embodies a short term focus on specific assets or projects; and

» the sequential nature of the revenue cap determination process which weakens the regulator’s ability to determine an optimal system wide investment program.

Information provision

As noted above, a key component of the NDR code changes was a policy shift from institutional responsibility for co-ordination (the jurisdictional planning bodies and the IRPC) to the reliance on information provision, consultation and dispute resolution.

The current arrangements for information provision and strategic analysis of projects with national benefits are limited to the ANTS together with the consultation and annual planning reporting obligations on TNSPs.

While most stakeholders supported the development of the ANTS, generators generally considered that further improvements could be made. VENCorp considers that reducing some of the information asymmetries that exist would provide increased certainty for the competitive sector, guaranteeing that existing and prospective market participants have ready access to the data and information they require in order to make informed and timely investment decisions.

Delta electricity states that the ANTS plays an important role in providing network capability information to the market. However, new generators are not given a clear picture of network capability across the NEM. The NGF submission to ERIG’s Issues Paper notes that information provision has improved with the ANTS overview but needs to improve further
with the provision of more detailed transmission information.

The additional information could include, but not be limited to, the power injection capability data at major potential connection points. This data would provide new generators with some idea of potential congestion when deciding on locational options for new plant. If new arrangements are implemented to explicitly price intra-regional congestion or to provide improved access certainty for generators then the additional relevant data could also be included in the ANTS.

Information provided to ERIG on a confidential basis makes the case that it is not possible, from the information presented in new network asset application notices (required under the TNSPs consultation process), to properly assess the impact a proposed new network investment would have. In many cases it was considered that alternative options have not been adequately presented or assessed.

On balance ERIG considers that the current ANTS does not provide optimum arrangements for information transparency particularly in the depth of scrutiny or level of disclosure it gives to the capability of the network.

**ERIG findings**

ERIG considers transparent information provision is a critical element of the national energy market irrespective of whether it relates to regulated or competitive elements of the market. Transparency in the provision of information is one of the corner stones for driving competitive and efficient investment outcomes.

ERIG considers that the current mechanisms for providing information have deficiencies and are unlikely to deliver the depth and quality of co-ordination needed to support efficient NEM-wide transmission, generation and customer investment.

**The way forward**

As noted earlier, Australia’s electricity demand is forecast to increase sharply over the next 10 years. The investment in generation required to meet the rising demand, will require a commensurately large investment in transmission. The previous section outlined the shortcomings ERIG has identified in the ability of the current framework to efficiently deliver the required outcomes for customers. The key challenge for policy makers is to ensure that measures are in place to support efficient investment in each sector and coordinate it to deliver the lowest overall cost of energy to customers.

ERIG is of the view that the arrangements for transmission planning, co-ordination and information provision can be enhanced to, inter alia, to better identify strategic network investments that maximise the national character of the transmission system; improve transparency and investor confidence and deliver technology neutrality across the national energy market.

There are a range of issues that, if addressed, could strengthen the overall planning and co-ordination framework. These issues are germane to all transmission planning and governance models, and include:
» supporting efficient generation investment;
» improving incentives on TNSPs and driving efficient operation of the transmission system; and
» improving coordination and driving the development of an efficient national power system through:
  - providing a consistent national framework for reliability standards and clarity in how the are interpreted and applied;
  - addressing the role and application of the Regulatory Test;
  - changing the form of the Regulatory Test; and
  - enhancing the information provided to stakeholders and ensuring process transparency.

Supporting efficient generation investment
The clear shortcoming identified previously in relation to the lack of signals for generators to locate efficiently requires urgent attention.

While not supporting a nodal pricing approach at this stage, the MCE has directed the AEMC to review the effectiveness of the current congestion management regime in the NEM and to consider improvements in congestion management.

The review is to provide guidance in three key areas:
» identification and development of improved arrangements for managing financial and physical trading risks associated with material network congestion, with the objective of maximising the net economic benefit to all who produce, consume and transport electricity in the market;
» take account of, and articulate, the relationship between a constraint management regime, constraint formulation, regional boundary review criteria and review triggers, the ANTS flow-paths, the last resort planning power, the Regulatory Test and TNSP incentive arrangements; and
» how the constraint management regime should apply as a mechanism for managing material and enduring constraint issues, until addressed through investment or regional boundary change.

ERIG is aware of the work that the AEMC is currently undertaking in this regard. ERIG considers that this has the potential to address some of the shortcomings of the lack of intra-regional pricing. In addition, the work of the AEMC needs to address the impact of the current arrangements on both productive efficiency in the short term and allocative efficiency in the longer term.

To achieve this aim, the Congestion Management Review needs to develop a regime which provides intending generators with an appropriate signal to locate efficiently within the existing network. An efficient regime in a competitive market context must, either explicitly or implicitly, price the cost of material congestion in the grid. In doing so, it will enhance the incentives to generators to invest in favourable locations relative to the grid.
The AEMC is also addressing transmission pricing arrangements under Chapter 6 of the NER. As highlighted in the preceding sections, transmission prices provide a muted signal to customers and no signal to the location of generators.

The AEMC has signalled that it will not be changing the arrangements relating to shallow connection charges for generators, nor is it considering changing the broader pricing arrangements that require all transmission revenue to be recovered directly from customers. However, ERIG notes that this issue is directly linked to the Congestion Management Review and elements of the transmission pricing regime may change as a result of the review.

The matters addressed in this review have been difficult to solve both technically and because of the range of vested interests represented in the market and the jurisdictions. The matter does though need to be addressed to deliver efficient outcomes in the longer term. The current market arrangements not only fail to send efficient investment signals to new generation proponents but in a number of cases raise perverse incentives. The implementation of national planning or other measures cannot, of themselves counter commercial drivers and deliver the most efficient overall power system.

ERIG has reviewed the terms of reference provided to the AEMC for the conduct of the congestion management review. ERIG has outlined some concerns with the AEMC’s scope to ensure its recommendations deliver the highest potential benefits for the market in the Governance section of the Market Structures chapter. This is evident in the terms of reference, particularly at items 3.1 and 3.2. The current terms of reference note the relationship between; inter alia, the regulatory test and TNSP incentive arrangements at item 3.2. However, other than a high level reference to the market objective at 3.1, no reference is made to economic efficiency. ERIG expects that the AEMC congestion review should deliver an appropriate management regime which will both improve the efficiency of operations and dispatch in the short term and meet the dynamic efficiency imperatives in the longer term.

Most solutions arising from this review can be expected to require transitional arrangements to fully implement. Transition measures to manage impacts on existing participants and the need to development of Rules and processes are likely. The outcomes of the review by the AEMC will be reported back to the MCE who should act to implement any recommended regime and the appropriate transition measures in a timely manner.

**ERIG finding**

ERIG considers that it is crucial that signals are put in place for the efficient location of generation investment. The AEMC congestion management review is the appropriate vehicle for delivering an appropriate regime taking into account the dynamic efficiency imperatives but the terms of reference for the review need to be clarified to ensure this outcome.

In addition, the inter-regional arrangements need to be fully examined with efficient and robust arrangements for the payment of inter-regional TUOS put in place. ERIG considers that the changes suggested in this report have the potential to increase the number of strategic investments being undertaken by TNSPs which are justified on the basis of benefits that extend past their own state borders. Accordingly, the transmission pricing arrangements
need to be capable of allowing for the incremental cost of network augmentation, where the project has been enhanced due to the potential for national benefits, to be met by the beneficiary state(s).

**ERIG finding**

The development of an efficient and robust inter-jurisdictional TUOS payment system will be necessary as the development of the transmission grid takes on a more national focus.

**Improving incentives on TNSPs and driving efficient operation of the transmission system**

Following consideration of the best approach to constructing a fully national and efficient transmission grid for the NEM, there needs to be in place a set of incentives on the network owners to operate their network in a manner that supports the efficient operation of the competitive market. This is achieved by ensuring that the network is available at its full capacity when the competitive market values it most.

The shortcomings of the current approach to performance incentives have been outlined previously. ERIG considers that a move towards a more sophisticated set of operational incentives would be beneficial. The AEMC, in its Final Determination relating to economic regulation of transmission services, increased the maximum service standard incentive from 1 per cent to 5 per cent of maximum allowable revenue.

The AER should develop incentives that are capable of encouraging the TNSPs to introduce innovative operational techniques to deliver more value to the market and hence to customers. ERIG notes that this would be consistent with the 2003 MCE report to COAG, in which the MCE flagged the development of market-based incentives for transmission by July 2004.

Information from the planning and the congestion management regimes should be used to enable the AER to better focus its incentive regime on the points of material congestion within the network.

ERIG considers that regulated returns should be based on the delivery of services rather than the provision of assets. The AER should be empowered and required to set specific benchmarks for the service level to be delivered in key areas such as the transfer capability between zones of the TNSP’s networks. The regulated revenue a TNSP earns should be tied to the delivery of those services. As such, penalties should apply to performance below the benchmark levels and rewards should be available for service provision above these levels.

However, ERIG notes that there are a number of circumstances which can contribute to congestion and hence the ability to meet service delivery targets, some of which may not be within the control of the TNSP in the short term. The development of better congestion management arrangements for the competitive sector should remove, or significantly reduce, the circumstances outside the control of the TNSPs. As a result, TNSPs should have greater control over the provision and maintenance of network service levels.
The AER has been developing a reporting system to analyse the market cost of transmission constraints. ERIG is of the view that this work is valuable and should be continued. The work could provide a basis for developing incentives on TNSPs to operate their networks more efficiently and in a manner sensitive to the market value of those services. ERIG notes that the AER and the ACCC before them have been working in this area for a number of years. The NER now requires the AEMC to introduce an incentive scheme by September 2007.

It is expected that the initial scheme will not be as comprehensive as ERIG envisages as necessary to drive efficient outcomes. ERIG considers that a comprehensive scheme cannot be finalised before the development and introduction of the AEMC congestion management work, given the strong relationship between them. The National Transmission Planning regime when developed may also be linked to such a regime.

The Rules provides that any changes to the scheme cannot be applied within 15 months and only then to the next round of five year revenue determinations. As such, even when incentives are developed, they will take some time to implement and embed in revenue determinations on TNSPs. There needs to be a focus on the timely and progressive development and implementation of market based incentives on the behaviour of TNSPs and the MCE should consult with the AER and set a timetable with appropriate milestones.

A Consistent National Framework for Reliability Standards

A clear shortcoming identified by ERIG is the different standards to which networks are built in each NEM jurisdiction. Additionally, schedule 5.1 of the Rules and the majority of jurisdictional reliability obligations lack specificity and require a significant degree of interpretation. This leaves the TNSPs with a large amount of discretion in the application of the reliability obligations to various points on the network.

In addition, in some states, responsibility for either setting the reliability criteria or for interpreting broad criteria contained in licence conditions is delegated to the TNSP. This could give rise to questions of conflict of interest where that TNSP also has responsibility for planning and investment. This conflict is exacerbated where the TNSP’s revenue and profitability is also driven by constructing assets to meet their own reliability requirements.

The lack of clarity and consistency of transmission planning standards leads to uncertainty for existing and potential market participants seeking to understand the basis upon which a TNSP will make an investment. It can also lead to potential asymmetries in the competitive market where different planning criteria are driving different regulated sector investment outcomes between jurisdictions.

Accordingly, ERIG considers that there would be a benefit in using a consistent national approach to specifying reliability standards across the NEM. ERIG has identified three potential candidate approaches to provide a consistent national standard for reliability:

- A probabilistic economic reliability standard;

The use of an economic planning criteria of this nature is consistent with the new International Electrotechnical Commission (IEC) Standards on Dependability Management and Reliability Centred Maintenance and would be preferable if considered solely on efficiency grounds. This level of reliability could therefore be seen as that level which should be delivered by rational planning criteria without the need
for supplementary standards. If this approach was to be adopted, however, a set of guidelines on how it was to be used and interpreted would be of value.

» A probabilistic outcomes based reliability standard; or

There may be value in supplementing the process of economic network development with additional standards which warrant a minimum standard of supply regardless of economics or which make TNSPs reliability obligations more measurable. The minimum standards in this option would set standards reflecting the expected customer experience at the connection point specified, for example, in terms of probable time off supply. ERIG notes that this is consistent with the standard currently used as the target for the competitive market of 0.002% unserved energy. In addition, utilising a probabilistic approach is technologically neutral and would facilitate the assessment of both network and non-network alternatives.

» A deterministic redundancy planning criteria.

A deterministic ‘n-x’ style planning criteria is currently applied in most Australian states and is the traditional approach used internationally. This option uses input standards based on network redundancy measures to infer appropriate minimum levels of reliability to customers. This option is arguably more easily interpreted and applied by TNSPs and conformance to such a standard can potentially be assessed by regulators. This type of standard needs to be carefully and specifically prescribed and modified from time to time to ensure that outcomes from such prescriptive standards remain appropriate. This form of standard is inherently technology specific and it would need to be supplemented to allow appropriate consideration of non-network alternatives. The submission by the Essential Services Commission of South Australia supports the efficacy of the South Australian arrangements of this form stating that “the definitive reliability standards in the ETC have proven to be transparent, easily understood by stakeholders, robust and relatively easy to implement and monitor” (ESCOSA 2006).

In any event, ERIG is of the view that reliability standards should at least be clear and specific as to how they are applied, be set by a body independent of the entity responsible for meeting these obligations and be cast in a technology neutral manner. Any technical standard should be defined as narrowly and clearly as possible. A consistent and clear national framework should be implemented through redrafting schedule 5.1 of the Rules. The Reliability Panel would be an appropriate body to undertake the necessary review and devise such a framework before the actual standards applying to individual connection points are specified by jurisdictions.

ERIG finding

As a component of developing a truly national character to the market, a more consistent, national framework should be developed for the setting of customer reliability standards. There may be long term benefits to making this framework consistent with the IEC standard on reliability centred design of transmission system.
Role and application of the Regulatory Test

The Firecone report prepared for ERIG outlines how the regulatory regime applying to TNSPs has evolved over time. In most states, that model is based on what Firecone refer to as a ‘standard’ regulatory approach described as follows:

“The ‘standard’ model creates efficiency incentives by periodically resetting a cap on the revenue that can be recovered from consumers through regulated charges, combined with a specification of the standards to be met. Typically the regulated entity retains some or all of the difference between the expected expenditure and the actual expenditure, for the period of the regulatory control. This gives it an incentive to minimise costs.

The regulated entity may also be subject to operational incentives to make transmission capacity available at times when it is of greatest value; and/or reliability incentives related to the quantity of unserved energy” (Firecone 2006b).

The important aspects of this form of regulation are:

» the setting of the ex-ante five year revenue cap;

» the clear specification of standards to be achieved and targets for service incentives; and

» the commercial behaviour of the regulated body.

The setting of the revenue allowance to apply for a period involves consideration of the opening RAB, as well as forecast capital and operational expenditure over the five year period. The recent Rule changes adopted following an AEMC review locks in the starting RAB and requires that actual capital expenditure within a period is rolled into the starting RAB for the next regulatory period. Consistent with the ACCC’s previous regulatory regime, there is no provision for the regulator to remove expenditure from the asset base ‘ex-post’.

As has been noted earlier, the role of a ‘test’ on capital expenditure during the five year regulatory period is therefore quite unclear.

The application of the Regulatory Test today is an obligation on TNSPs that has value through its role as a consultative mechanism and which provides some transparency on the TNSP’s decision making particularly in respect to the ranking of various project options. The Regulatory Test may also have specific application to ‘contingent’ projects or those outside the ex-ante revenue cap. ERIG continues to accept the analysis by Firecone that the links between the Regulatory Test and the economic regulatory regime are tenuous at best.

ERIG considers that the role of the Regulatory Test within the Regulatory Period then needs to be reconsidered as the original concept is inconsistent with the current and proposed regulatory regime. ERIG propose that both the form and functioning of the Regulatory Test needs to be completely changed as a result.

ERIG finding

ERIG considers that the original role of the Regulatory Test is inconsistent with the emerging regulatory regime and both its form and function needs to be changed as a result.
Form of the Regulatory Test

ERIG considers that the current form of the Regulatory Test is inappropriate as:

- a project by project assessment cannot be expected to deliver efficient, long term development of the national network; and

- a two limb approach attempts to artificially identify and justify an individual project as either providing reliability or market benefits where in reality any network augmentation is part of a total network which delivers both (i.e. reliable and efficient supply).

ERIG considers that the Regulatory Test should be replaced with a two step process to guide efficient transmission investment as follows:

First Stage

The first stage of the investment decision making process proposed is to establish an overarching longer term plan for the efficient development of the national transmission network. This should be determined on the basis of a set of overall national efficiency objectives. Those objectives should effectively integrate the two limbs of the current Regulatory Test and seek to develop the network in a manner that maximises net market benefits whilst ensuring that customer reliability standards are maintained. The development of a longer term plan under a set of efficiency objectives potentially provides the opportunity to also consider gas pipelines as a potential competitor to transmission projects. The proposed National Transmission Network Development Plan would be developed in full consultation with interested parties.

The current Regulatory Test approach seeks to apply on a project by project basis. Under this approach, the decision making is not applied to an individual project in isolation, but rather from the perspective of the network as a whole. The governance of the process and the involvement of network users in that process would aim to ensure the integrity of the process and the outcomes would inform:

- the planning of individual TNSPs;
- the AER in seeking to determine the ex-ante revenue cap and develop incentives; and
- market participants.

A number of respondents supported the need for longer term, nationally focussed plan for the development of the network. However some respondents also cautioned against too rigid a plan. ERIG fully acknowledges that in a dynamic market context, a network development plan can not be totally prescriptive or set in concrete. The plan and planning process would need to recognise and integrate uncertainties and be updated on an annual basis. On the other hand, planning is essential if the nation is to reap the benefits of efficient development of the network in the medium to longer term.

ERIG finding

A project by project assessment cannot deliver the efficient, longer term development of the network. The introduction of a strategically focussed National Transmission Network Development Plan would assist in the efficient, nationally coordinated development of the network.
Second stage

Within the regulated period, the relevant network service provider should consult on individual projects to ensure that the specific works proposed are the most appropriate and that alternative non-network solutions are fully considered. Here again the two limbs of the Regulatory Test should be integrated as part of a single Project Assessment and Consultation. This process should ensure that options considered:

- are consistent with the long term directions of National Transmission Network Development set out in the plan developed in the first stage;
- will meet the relevant customer reliability standards; and
- minimise net costs or maximise net market benefits against alternative options.

This would allow consideration of alternative options to meet a reliability requirement that also maximise net market benefit, even if in terms of meeting the narrow local reliability requirement they are not strictly least cost. This is consistent with the approach adopted in the long term national plan and addresses concerns raised by stakeholders that there are examples of projects where an incremental addition to the project would have delivered net market benefits, but these options could not be considered as they did not meet the least cost criteria of the Regulatory Test reliability limb.

The Project Assessment and Consultation process would need to be developed recognising the importance of its consultation role and its function to ensure proper consideration of non-network alternatives. ERIG considers that engagement with interested parties and transparency are essential in the development of the longer term plan and should both aid efficiency and enhance investor confidence in the competitive market. The governance over the development of the longer term national plan provides appropriate independence in the application of the Network Development Objectives in the first step. The overall process is summarised in figures 16 and 17.

16 Proposed national network development arrangements
Consideration should be given to the potential benefits of independent conduct or review of the application of the Project Assessment and Consultation process and of formal involvement of network users in the process. These issues are already dealt with in South Australia and Victoria. The submission to ERIG from Firecone on behalf of the Victorian Department of Infrastructure includes results of a survey of major private sector investors demonstrating they have higher confidence as a result.

**ERIG finding**

ERIG recognises the value to the market of project by project consultation. ERIG therefore considers that a Project Assessment and Consultation process be developed and applied prior to final commitment on expenditure on major augmentation projects. This process should also be designed to ensure proper consideration of non-network alternatives.

**Link to consistent national reliability standards**

The potential benefits from pursuing this option could be eroded if the recommendation to develop a consistent national framework for expressing reliability standards is not implemented and that the standards and the way they are to be applied is not clarified and made more specific. ERIG considers that that the new Project Assessment and Consultation process should also be applied on a consistent national basis.

ERIG considers that integrating the two limbs of the test without harmonising and increasing the specificity of reliability and planning criteria will introduce additional risks. The differences in standards and any uncertainties in the way in which reliability requirements are interpreted and applied in each state would be compounded by allowing market benefits to be added to the reliability limb of the test, further increasing its subjectivity.

**Economic basis of the test**

ERIG also considered the issue of the inclusion of so-called ‘customer benefits’ in the Regulatory Test framework. The Regulatory Test framework is intended to approve projects only where economically efficient investments can be identified. Similar to the ‘market benefits’ limb of the current test, an investment is only considered economically efficient where the additional economic gains to market participants, accounted across both consumers and producers, exceeds the economic costs of the investment.

In submissions to ERIG, both the Major Energy Users and the EUAA suggested the use of the so-called ‘customer benefits’ in the Regulatory Test framework instead of the current market benefits test. The design of the ‘customer benefits’ intentionally only counts the economic gains to consumers in the market. However, apart from the cost of the investment itself, a customer benefit test excludes any economic losses to firms involved in supplying energy to the market.

Deliberately excluding economic losses to firms in the industry effectively lowers the hurdle to proposed transmission projects, skewing the investment mix towards transmission investment away from generation investment. However, such a test is fundamentally flawed and is likely to lead to economically deleterious outcomes.
In an electricity market, the economic rents (or profits) accrued by generators are required to pay for the substantial fixed costs associated with building power stations. In a fully competitive market, economic profits to generators are just sufficient to induce both the right level of investment in generation and the right mix of technologies.

Skewing the investment decision making framework in favour of transmission investment, risks crowding out other potentially economically efficient solutions, such as local generation or DSM. This will, over time, lead to an economically inefficient mix of location and generation fuel type and a resultant increase in the total cost of electricity delivered to consumers.

As such, ERIG notes that whilst a project may be said to have passed a ‘customer benefits’ test, it may ultimately be total welfare depleting, and hence cannot be economically efficient. Accordingly, ERIG does not consider a move away from a market benefit test, as is currently utilised in the market limb of the Regulatory Test, is warranted.

### ERIG finding

Although ERIG recommends changes to the form and function of the Regulatory Test, it affirms the economic principles underlying it as the appropriate assessment criteria underpinning network planning and investment. ERIG further considers that the current two alternative approaches to justifying investment should be amalgamated.

### Capital expenditure incentives

The development of effective incentives on efficient transmission investment faces a range of difficulties. As highlighted in other sections, the efficiency of a transmission network investment cannot be judged in isolation from investment in generation and customer demand. This makes it difficult to measure performance in the absence of an established benchmark. The process outlined has the prospect of informing the regulatory regime and assisting the AER to set a benchmark as to the service levels a given 5 year capital investment program would be expected to deliver.

It is also difficult to deliver efficient capital spending incentives where there is a potential for capital spending to be efficiently offset by operating expenditure. ERIG has considered methods of ensuring that non-network options are appropriately considered as part of the consultation process for new network augmentations. Whilst the current arrangements require TNSPs to consider non-network options, this does not address the underlying skewness of the regulatory regime towards capital expenditure over operational expenditure.

A stronger incentive regime premised on better information as to the longer term development of the whole power system is expected to minimise that bias. It is not clear to ERIG, however, that it is possible to ever fully balance the incentive to seek a capital expenditure solution over an operational expenditure solution or an external solution over an in-house investment.
Information Provision and Process Transparency

A key role of any transmission planning and consultation process is to deliver information to the broader market. Efficient investment in generation relies on a range of national market data, including information on the current and potential future capability of the transmission system it relies on to trade in the NEM.

Further, the certainty of investors is enhanced where there is a reasonable expectation that other investors, including investors in transmission infrastructure, will make investments on the basis of commercial considerations only. Information transparency and the predictability of the transmission investment decision making process are important elements of achieving this certainty.

Where investors are considering potential generation investments, understanding the performance of the network and its likely development options are vital to assessing the risks associated with a particular connection location. In order to increase certainty for the competitive sector, investors need confidence in transmission data and the ability of the market arrangements to predictably deliver efficient network investment.

ERIG considers that the current arrangements, that require the publication of an APR in each state and the publication of the SOO and the ANTS by NEMMCO, fall a long way short of a first best solution for a robust information provision regime. ERIG considers that the current information asymmetries between the TNSP and parties seeking to comment on revenue applications needs to be addressed.

The proposed national planning process would provide an independent source of information on the potential and planned network development options. Involvement of network users in the process should ensure a robust process that provides and information at various levels of detail and over various timeframes.

**ERIG finding**

ERIG considers that the National Transmission Network Development Plan should replace the role of ANTS as an information platform which facilitates planning and investment decision making across generation, load and networks. Network users should be formally involved in its development.

The requirement for individual TNSPs to publish information annually through their APR’s and on each project through a new Project Assessment and Consultation process should further address market information needs. The scope exists in several jurisdictions to improve confidence in these processes.

The provision of more detailed information would also assist in further developing the regulatory framework, particularly with regard to the revenue determination process and performance incentive arrangements.
National Transmission Planning and Governance Arrangements

As highlighted above in the Delivering a fully national and efficient system section, the current arrangements for transmission planning in the NEM lack national coordination and are unlikely to deliver a network which meets the markets needs on an efficient national basis. This is despite the establishment of the ANTS in 2004.

ERIG considers that there are substantial gains to be made in establishing effective national planning and co-ordination. Accordingly, ERIG has considered planning and governance options that would add the ability for planning to be undertaken from a NEM wide perspective, over and above that currently conducted. The objective of any option is to support the delivery of efficient investment in the national network and the power system more broadly. Therefore consideration of the integration of any planning function into the regulatory regime for transmission will be an essential part of the assessment of national planning options.

ERIG’s Discussion Papers outlined 3 broad options for national transmission planning. In arriving at those options, ERIG considered a range of measure to achieve national planning and co-ordination of the development of the power system in the light of the key shortcomings identified above. Critically, reliance on completely regionalised planning may fail to deliver efficient expansion of the integrated transmission network across the NEM as a whole. Accordingly, ERIG has considered planning and governance options that would add the ability for planning to be undertaken from a national perspective, over and above that currently conducted.

Each planning model considered below delivers different challenges and opportunities in terms of information provision, investment drivers, regulatory arrangements and operational incentives/sanctions. Each model has costs both in implementation and operation. Those costs need to be commensurate with the scale of the identified problem to ensure the likely benefits exceed costs.

The EUAA submission on ERIGs Issues Paper noted that one option for delivering national co-ordination and the identification of optimal projects to transmission in the NEM would be the establishment of a national grid company. This national grid company would own the entire NEM transmission network. The EUAA notes that either the national grid company or a separate body could be responsible for transmission planning. The EUAA suggests that the national grid company would provide a seamless and nationally consistent approach to the transmission system, operating under a national charter that is consistent with the NEM objective. Local offices could also be established to ensure a local presence and responsiveness. The EUAA goes further, suggesting that local jurisdictional considerations could be included, although these considerations should be consistent with the national focus and national market structure.

The EUAA states that this model has operated successfully in the United Kingdom and several other countries, and is a structure that is also increasingly being adopted in the United States through a movement towards larger Regional Transmission Organisations. ERIG notes that the market model in these cases is a Transmission and System Operator (TSO) model in which the transmission asset owner and system operator are one and the same organisation.
The NEM has adopted a fundamentally different model establishing a system and market operator (NEMMCO) that is independent of transmission asset ownership. This alternate model is used in many leading power markets internationally including the major markets in northeast USA. Implementing an effective TSO model in Australia would require a fundamental redesign of the market architecture and a transfer of NEMMCO’s responsibilities for system security (or system operator) role. This dilutes responsibility to maintain system security and raises issues with the separation of the system operator from the market operator (IMO).

In addition, ERIG concurs with EUAA that transferring all assets to a national grid company may now be impractical because of mixed government and private ownership and in any case would be very expensive. The commercial value of all transmission assets in the NEM based on recent market transactions for similar regulated assets would be in the order of $16 billion.

A further consideration is the potential issues associated with regulating a single monopoly transmission entity. ERIG considers that, given the technical nature of the electricity industry and the existing information asymmetry, the co-ordination benefits gained from such a model may be dissipated through difficulties in regulating it.

Given the significant costs and risks involved in implementing this model when compared to the likely benefits of its adoption, ERIG does not intend to further consider this option. ERIG notes that the potential co-ordination benefits of this option can be achieved through other less costly options, including the three options discussed below. These are:

- modified status quo or National Transmission Planning Coordinator (Option 1 in the ERIG Transmission Discussion Paper);
- strategic national planner or National Transmission Planner (Option 2 in the ERIG Transmission Discussion Paper); and
- National Transmission Service Procurer (Option 3 in the ERIG Transmission Discussion Paper).

Consultation raised questions from several respondents as to the need for any national planning process beyond that already existing. ERIG considers the justification is clear and has provided further evidence to support its recommendation. No respondents proposed alternative models for consideration. ERIG therefore considers that these are the broad models to be considered, recognising that there were a number of comments on the detail of each model.

**National Transmission Planning Coordinator**

The formation of a National Transmission Planning Coordinator or modified status quo model continues reliance on information disclosure and consultation for national co-ordination. The model would improve transparency of information provision to TNSPs, the broader market and the market institutions.

This option gained some support from some parties including SPAusnet. The TransGrid and ETNOF submissions seek to assess each of the three options against their own set of criteria. Accordingly these stakeholders rate the current arrangements highly and accept the value of the proposed refinements inherent in this option.
The Energy Intensive Industries Alliance endorse the view that the transmission network is poorly coordinated and strongly supports the need for a national transmission planner but cautioned against the formation of just another layer of bureaucracy without careful consideration of how the overall arrangements will drive efficient decision making.

ERIG considers that this option does not go far enough and is unlikely to achieve the efficiency gains sought. While better coordination of national information and more involvement of market participants in its development have merit, the process continues to rely upon planning on a region by region basis. As demonstrated above to ignore this fundamental weakness is to ignore important national market efficiency gains from integrated consideration and development of the national grid. The option:

» would be unlikely to deliver the level of co-ordinated, efficient investment in each region required to ensure nationally integrated long term development of the network; and

» would not directly address investment and operational incentives delivered through the economic regulatory regime.

Overall this model is only likely to provide marginal benefits towards a fully national and efficient grid in the absence of a strong link between planning information, congestion management and regulatory incentives. ERIG does not recommend this option.

National Transmission Planner

The National Transmission Planner model proposed would include the improvements set out under the modified status quo model. In addition to the independent and transparent provision of information, the model would strengthen national co-ordination through allocating a broader set of responsibilities and resources to the National Transmission Planner.

The National Transmission Planner would be charged with the development of an independent strategic national plan outlining the broad development of the power system and the national transmission network with a minimum outlook of ten years updated annually. The planner would have statutory responsibility for the development of the National Transmission Network Development Plan (NTNDP) in accordance with given objectives.

The body would be responsible for formally involving both TNSPs and network users in the development of the NTNDP and to consult on the Plan. It would maintain the resources necessary to develop its own independent assessments. Most importantly, the National Transmission Planner would have an obligation to advise the AER in respect of the appropriateness of capital spending proposals in revenue cap submissions by TNSPs. This would ensure that the NTNDP is given greater relevance by strong links with the regulatory regime.

Individual TNSPs would remain responsible for meeting standards and for their investment decisions during the 5 year regulatory period. Importantly, this also means that TNSPs remain accountable for outcomes. The AER would remain responsible for setting revenue caps but would also benefit from additional and more transparent planning information to aid it in setting the ex-ante revenue cap.
The model relies on incentives within the regulatory regime to operate and invest efficiently and minimise the costs of meeting these defined obligations. As a result it also requires links to information generated by a congestion management regime.

Responsibility for conducting the Project Assessments and Consultation process on each major augmentation before implementation would remain with individual TNSPs but the national planner may have a role in reviewing its application. The option for independent review of the conduct of the Project Assessment and Consultation process would be a further mechanism to ensure that non-network options had been appropriately considered by the proponent.

Allocating responsibility for actually undertaking network analysis and planning in the development of the longer term plan will increase the resources required by the National Transmission Planner when compared to the coordination role in the modified status quo discussed above. It will, however, ensure a clear focus on integrating national network development and remove any difference in the assessment of intra- versus inter-regional investment and investment aimed at providing reliability versus market benefits. This body would also have the capability to provide a credible, independent source of advice to the market and the regulatory regime.

This model offers the potential for greatest efficiency gains through effective links between planning and the economic regulatory regime where:

» regulatory revenue resets are simultaneously determined and the regulator gives consideration to each individual TNSPs plan in the context of the NTNDP;

» the regulator imposes a revenue cap which is based on its assessment of efficient NEM-wide investment, informed by the NTNDP; and

» regulatory incentive arrangements are put in place and utilise information on the expected network performance in the NTNDP.

17 Two tier decision making process – coordinated approach
The effectiveness of this option is dependent on the strength of the regulatory regimes and the incentives it provides for efficient operation and investment.

The model is consistent with the broad policy framework set by the MCE for transmission, building on increased information provision and transparency, market based incentive arrangements for TNSPs, work on congestion management, the last resort planning power, streamlined dispute resolution processes for the Regulatory Test and revised regional boundary change arrangements.

This option has been criticised by VENCorp on the basis that:

“VENCorp believes that (option 2, the strategic national planner and co-ordinator) will create conflict between the national planner, asset owner and regulator and lead to a lack of clarity in the responsibilities and accountabilities of each of these organisations” (VENCorp 2006).

The proposed role of the National Transmission Planner in this model is focussed on the longer term development of the network and it is not clear that this role necessarily conflicts with that of the TNSPs. The current arrangements in most states depend fundamentally upon the assessment of an appropriate ex-ante revenue cap for each regulatory period.

The information and directional framework provided by the national planner is expected to significantly improve this process compared to the current arrangements where there is currently a significant information asymmetry.

VENCorp also argue that:

“Further, this proposal will result in duplication of functions between the asset owner who is still responsible for undertaking network planning for reliability investments and the national planner” (VENCorp 2006).

The proposed reforms to the Regulatory Test and the decision making process for new investment integrate consideration of reliability based investment and that driven by net market benefits. Its focus on the longer term national plan is in part new work which is projected to add substantial value. To the extent that some of the work is currently undertaken by NEMMCO the resources would not be all additional. There is the risk in all of these options that interfaces of responsibilities can create overlaps and these need to be minimised by the detailed operating arrangements. SP Ausnet considers that:

“it is possible to develop a practical version of Option 2, which would meet ERIGs objectives, and which would lead to a more consistent, efficient and effective transmission planning regime than other alternatives. SP AusNet presented this option in more detail in our submission into the Review of VENCorp Functions.

In this submission we presented an alternative approach, a planning oversight model and contrasted this with the services procurer model. The planning oversight model was presented as a practical approach that would address the issues that SP AusNet have experienced with the services procurer model, and would provide a consistent and effective transmission planning regime, leading to the development of a highly accountable transmission network services sector. The model aligns with ERIG’s Strategic National Planner and Coordinator model (Option 2)” (SP AusNet 2006).
The effectiveness of the regulatory regime and the commercial incentives it offers is also dependent upon the behaviour of the regulated entities. The success of this model from a governance perspective depends upon the adoption of recommendations discussed in the market structures chapter of this report. Failure to address the issue of government ownership may also result in the model being undermined:

» where the regulator faces political pressure not to reject a government owned TNSP’s capital expenditure proposal; and

» where a TNSP (in the absence of an appropriately powered commercial incentive regime) is driven by government policy objectives, rather than seeking to maximise profits. The result may be to alter the profitability of the TNSP rather than affect investment decisions. This counter incentive can be managed where performance benchmarks are explicit and transparent.

**ERIG finding**

ERIG considers that the National Transmission Planner model will provide significant benefits towards a fully national and efficient grid and is consistent with COAG and MCE transmission policy directions since 2003.

The preferred model also allows the arrangements for transmission to continue to evolve. Whilst the resources required and costs of this option are greater than a simple coordination function, the formation of an independent process to inform both the market and the regulatory regime can be expected to drive efficiencies in excess of its costs. The implementation of this model is also far simpler than the implementation of a National Transmission Service Procurer, the option considered next.

**National Transmission Service Procurer**

The National Transmission Service Procurer model involves the establishment of a national body responsible for planning and procuring transmission services, but which would not own the assets. This model facilitates national co-ordination and strategic planning of the network development as in the option above but goes further into implementation of that plan, deciding the services which ought to be provided (or the investments which ought to be made) and securing those services by a combination of competitive tender and negotiation.

The Service Procurer model requires a line of accountability to be drawn between the investments and services for which the individual transmission owner is responsible and those for which the procurer is responsible. This model then requires a different approach to the regulatory regime and the way in which efficient outcomes are to be delivered.

For those services for which the procurer is responsible, efficient development of the network relies upon good decision making by the independent, not-for-profit body established for the task. The cost of implementing these decisions would then be passed through to customers. Cost effective delivery of the assets or services determined to be efficient is then pursued through the procurement process and efficient operation would be delivered through the implementation of service level agreements with the service procurer.
The implementation of this model would require significant changes to the legal framework and regulatory regime along the lines of the derogations that currently apply to Victoria. It would also require considerable supporting legislation in each state to establish the role and function of the procurer and to provide for physical access to the transmission network to provide for the involvement of other asset owners connecting to the network.

The balance of the network investment not determined by the national service procurer would be left in the hands of the primary asset owners in each state. This would include, as a minimum, all replacement and refurbishment work and a range of smaller projects. The experience in Victoria highlights that the majority of capital expenditure would still be the responsibility of the asset owner ($130 million of contestable works compared to $370 million of capital investment provided for under SP Ausnet’s revenue cap). Efficient use of capital in this area would be driven through the normal 5 year ex-ante revenue regulation process.

A key component of this model is the need for the legal framework to define the services to be provided by the asset owner, allocate accountabilities and deal with the associated allocation of risk inherent in separating the planning from asset ownership. In Victoria this is in part embodied in a complex ‘network agreement’ between VENCorp and SP Ausnet. The Victorian experience demonstrates that implementing this model would require considerable time and resources.

Transparent information provision and consultation arrangements should be delivered through the body’s establishment arrangements. The independent performance of the planning role and the additional level of transparency delivered by this model has been valued by a number of generators in their response to ERIG. If the model was to be applied in the NEM as a whole, then the national body would need to maintain the level of local network knowledge necessary to maintain its effectiveness in regional network planning. This issue could be overcome by the establishment of regional offices and a balance between central and delegated decision-making.

Investment decision-making and asset ownership are separated under this model. The resultant requirement for a strict sequential planning process may have implications for the timeliness of transmission investment, particularly in regions experiencing high demand growth.

The separation of investment decision-making and asset ownership relies on investment efficiency drivers delivered through the governance arrangements of the institution (particularly where it is not-for-profit) rather than the commercial risk associated with a for-profit entity. The governance of this body is then critical to good decision making and the success of this model.

TransGrid and ETNOF, in their submissions on ERIG’s Discussion Papers, consider that:

“The ‘national procurement model’ scores poorly across a wide range of crucial assessment criteria including:

Clarity of accountability for the delivery of service outcomes (including reliability) between the ‘procurer’ and the asset owners;
The ability to use regulatory incentives to drive the performance of the ‘procurer’, including to achieve efficient and timely investment decisions and efficiently ‘trade off’ augmentation with non-network options;

Timeliness of investment delivery due to the inability to readily integrate the environmental approvals (particularly for new line development) with options assessments; and

The efficient interaction between the national ‘procurer and regional network planning involving distribution providers, local generators and major end users’ (Transgrid 2006).

On the other hand, VENCorp believes that “only Option 3, the national transmission service procurer, will meet ERIG’s key objective of maximising economic efficiency and address the impediments identified.” TRIenergy also argues in its submission (page 9) that “whilst (the ‘national transmission service procurer’) has the greatest transitional challenges, it ultimately provides the best model both in terms of market confidence and cost.” The performance analysis undertaken by MMA for ERIG, although qualified, does suggest that the model has delivered relatively high capital productivity growth for Victoria.

The National Transmission Service Procurer model represents a major step away from the current direction of development of the regulatory regime and drew the most polarised of responses. SP Ausnet argues at page 2 in its submission that:

“In reality it must be recognised that option 3, and an approach in which service incentives are provided (for transmission service, and not simply asset availability) are mutually exclusive. Option 3 is intended to replace the need to provide incentives on decision makers by ensuring that the decision maker is independent, and has no commercial interest in the outcomes of decisions” (SP Ausnet 2006).

This model faces considerable costs to implement and would be particularly difficult to introduce into South Australia because of the commercial arrangements there. This option is not discounted and may even be preferred by jurisdictions as a component of larger structural and ownership changes. However the empirical evidence of the scale of the current problems and the scope for improvement does not argue that such a major change is necessary.

Implementation of national planning arrangements

The proposed planning regime would need considerable development before implementation and the appropriate body to lead that work would be the MCE. The model would primarily be implemented in the Rules, with appropriate amendments to the NEL.

Consistent with the market governance arrangement, the MCE should commission a review by the AEMC to detail the planning framework recommended by ERIG and advise on any necessary changes to the NEL and the Rules. The review would need to examine:

- the detailed role and functions of the National Planner to operate under the umbrella of a reformed NEMMCO;
the rules and processes required to develop a National Transmission Network Development Plan on an annual basis, including the responsibilities for market participants and network service providers to provide information to the National Planner and the Role and function of the Panel providing the formal mechanism for the involvement of industry participants and other stakeholders in the development of the Plan;

the links between the National Planner and the NTNDP and the regulatory regime and, in particular, the way in which these should inform the process for setting the ex-ante revenue cap;

the potential for links between the National Planner and the NTNDP and the congestion management regime arising from the AEMC review;

the objectives under which the National Transmission Network Development Plan should be developed (based on integrating the two limbs of the current Regulatory Test);

requirements for network service providers to undertake a Project Assessment and Consultation process on all major augmentations prior to final commitment. This process should ensure transparency around the decision to implement a particular solution including the assessment of non-network alternatives and demonstrate how the project is consistent with longer term development directions in the NTNDP; and

consider the value of other Rule changes consequent to the introduction of the national planning process and the formation of the National Planner such as changes to any Planner of Last Resort role.

This work would also need to address any consequential amendments to the Rules and Law. The National Planner would, for example, replace the role of the IRPC and the NTDP should replace the ANTS. The implementation of the NTNDP and the arrangements for a Project Assessment and Consultation would replace the current Regulatory Test. The MCE should then act to implement the proposed regime. The implementation is contingent upon changes to NEMMCO’s governance discussed elsewhere and individual jurisdictions would need to examine any changes required in their own regime to implement the national model.

Future review of national planning arrangements

The National Transmission Planner model is recommended on the basis that it would complement current reforms and would incur costs commensurate with the identified needs. The model is consistent with ERIG’s view that a framework whereby commercial bodies act under financial incentives is the most appropriate model for the energy industry.

ERIG notes, however, that this model relies upon ongoing reform to the regulatory regime to bring to bear appropriate incentives on TNSPs’ behaviour and thereby drive efficient outcomes. It also relies upon the National Transmission Planner developing an effective role based on informing the market and the regulatory processes without the supplanting the accountabilities of individual parties.
The performance of the proposed national planning regime needs to be reviewed within five years. This review should consider whether the incentive regime on TNSPs together with the coordination and advisory function of the National Transmission Planner have produced efficient outcomes or whether the role of the national planner should be extended to provide it accountability for decision making and procurement of transmission services; that is, whether the move to a National Transmission Service Procurer would be warranted.

**ERIG finding**

ERIG considers that the National Transmission Planner option would complement the existing arrangements in most states and maintain current accountabilities. This model would seek to inform the regulatory process and drive efficient outcomes through commercial incentives on the responsible TNSPs and is the model recommended by ERIG.

The National Transmission Service Procurer option provides an alternative model if COAG considers the addition change is justified on broader grounds.

A review of national planning arrangements should be undertaken in five years to review whether the commercial incentives regime supplemented by the National Transmission Planner have been effective or whether the arrangements should progress to the National Procurer Model.

**Governance options**

ERIG has considered the two potential models for the placement of the national transmission planning and co-ordination function. The options to be considered for the location of the national planning function in the NEM:

- the creation of an independent new entity; and
- placement of the planning function within NEMMCO, subject to acceptable changes to the governance of NEMMCO itself.

ERIG’s Transmission Discussion Paper also raised the alternative of placing the function with the AEMC perhaps along the lines of the Reliability Panel. This option had little support from respondents and does not deliver the synergies of combining the functions with NEMMCO or the independence of a freestanding body. This option is therefore not considered further.

The choice of planning option will, to some extent, dictate the choice of governance model, as each option will give rise to different conflicts within the existing institutions. Governance issues more generally have been addressed in chapter 5 of this report and issues raised there are pertinent to the arrangements for transmission planning.

**The creation of an independent new entity**

ERIG considers that there are some advantages in the establishment of an independent new entity responsible for transmission planning. However, ERIG also recognises that such an option increases the costs of addressing national transmission planning significantly, and may not be justified at this stage.
The creation of a National Transmission Service Procurer would appear to create conflicts with the functions of both the AEMC and NEMMCO that can not be easily managed by any form of operational separation. Accordingly, the nature of the national transmission service procurement model appears to preclude options other than an independent new entity. The governance of such a body is critical to the delivery of efficient outcomes in that model.

The Firecone report analyses governance issues for NEMMCO and proposes a model which seeks to provide a Board with an appropriate range of skills and which is nominated by industry and government but which maintains independence and avoids the perception that any Board member is ‘representing’ either a specific government, or a section of industry. This type of model would be appropriate for the governance of the National Transmission Service Procurer albeit a completely separate body requiring a somewhat different mix of skills.

**ERIG finding**

ERIG does not consider that the additional cost of creating a separate national planning body is warranted at this time unless COAG agrees to proceed with a National Transmission Service Procurer model.

**Establishment as part of NEMMCO**

ERIG considers that the governance of NEMMCO requires close examination prior to any consideration of situating an enhanced planning role within NEMMCO. This matter has been addressed in chapter 5 of this report.

ERIG sees significant benefits in reforming the governance of NEMMCO on fundamental grounds regardless of the placement of any national planning function. In addition, the reform of NEMMCO’s governance would make it a far more suitable body in which to place a national planning function.

If NEMMCO was to be governed by a Board with more independence, greater industry involvement and one which was seen to have a more national character, there are some benefits to be gained from placing the national transmission planning function with that organisation. The case for the co-location of responsibility for network planning and system operation is bolstered by the potential synergies in information required to perform each respective role.

NEMMCO currently has a planning function and convenes the IRPC. NEMMCO also has offices in three states which potentially provide a basis for a broadly based planning function with local expertise. The proposed National Planner is a significantly different and larger planning role, however, and would need a new approach. The new Board would need guidance on its objectives and obligations in performing these new functions. Firecone notes that there is currently a lack of objectives to guide NEMMCO’s Board more generally, viz:

“The Code previously included objectives for NEMMCO which could guide Board decisions. It would be desirable to establish transparent objectives in the Rules or in legislation. These could establish that the Board is responsible for ensuring that NEMMCO undertakes its functions in the way which best meets the NEM objective, or alternatively set out more specific NEMMCO objectives, as previously done” (Firecone 2006b).
The expansion of NEMMCO’s role would indicate a need for specific objectives to be established. These should address the planning function objectives as distinct from objectives in other areas and assist in managing any potential internal conflicts.

**ERIG finding**

ERIG recommends that the governance of NEMMCO be reformed and that the National Transmission Planner be placed within that organisation.

The placement of this much expanded function in NEMMCO would require significant change in NEMMCO. The operation of NEMMCO more generally, and particularly in taking on a much expanded planning role, would benefit from a set of specific objectives to guide its Board and management.

**Industry and stakeholder involvement in the development of the National Transmission Network Development Plan**

ERIG considers that the development of a ‘National Transmission Network Development Plan’ is not possible without understanding and analysing potential developments in the competitive sectors, the nature and location of likely generation investments and the location and growth of customer load.

The planning would necessarily need to take account of a range of likely scenarios for the development of the overall power system in developing any network plans. The planning implicitly trades off the costs and benefits of increased transmission transfer capability between points in the network against the costs and benefits of various generation locations. The availability of fuels and potential costs of fuel transport including gas pipelines is a critical component of these considerations.

To develop such a plan requires a range of inputs and advice and oversight from a range of industry participants and stakeholders is essential to the plan’s quality. The knowledge and insights of TNSPs and distributors in respect to their networks would be an essential input to the development of the plan as would the insight of participants in the competitive sectors of the industry. As such, the formal involvement of industry representatives and stakeholders in the development of the plan should be provided for in the Rules.

The formation of a Panel to assist in the development of the National Transmission Network Development Plan would also improve the transparency of the process and ensure that the information provided was appropriate to the needs of all stakeholders.

**ERIG finding**

ERIG considers that the implementation arrangements for the National Transmission Planner and the process for the development of the National Transmission Network Development Plan should provide a formal mechanism for the involvement of industry participants and other stakeholders.
Potential issues for Western Australia

The discussion and analysis in this chapter and the proposed arrangements described above relate specifically to the NEM; i.e. the interconnected transmission grid covering Tasmania and the eastern states from South Australia to Queensland.

The market arrangements in Western Australia are different to those in the NEM and have only been established for a relatively short period of time. The Western Australian power system is not connected to the NEM and will remain so in the foreseeable future. An electricity market began in Western Australia on 21 September 2006. Given the limited experience with the arrangements to date, ERIG has not made a range of specific recommendations for change in Western Australia at this time as it has for the NEM.

However, Western Australia operates a transmission network over a wide area and in a competitive market context. ERIG’s examination of how a competitive markets for energy, generation and customer retailing operate and invest along side regulated markets for the supply of transmission and distribution services and deliver an efficient outcome overall should be of value to Western Australian policy makers.

The key principles for the efficient development of the Western Australian power system should be similar to those applying in the NEM and ERIG has recommended exploring the potential to use national institutions for its development, operation and regulation. The use of national institutions would not only contribute to a nationally consistent framework but would also allow a number of potentially conflicting roles currently performed by the IMO to be separated.

The Western Australian network access arrangements provide a locational signal to new entrants by requiring generators seeking to connect to the system to partially fund any augmentation required of the shared network. The shared system is to be augmented with each new entrant to maintain low levels of network congestion.

The regime has some benefits but appears to be in early stage of development. It is not clear whether it can be consistently applied or whether it will ensure overall efficient power system development. The effectiveness of these arrangements should be reviewed over time. The nature of the network and the access arrangements minimise the congestion that occurs in dispatch. Dispatch in the short term forward market is not security constrained and therefore not prices. Any congestion which does occur appears to be pragmatically deal with in the power system operations area. The clarity and efficiency of this regime and its effectiveness as the market develops will again need to be watched.

There are potential advantages in applying the general principles recommended for transmission in the NEM to Western Australia in terms of:

- an appropriate congestion management regime in the short term forward market to provide clarity and drive dynamic efficiency in the operation of the power system;
- market based incentives for efficient service delivery by network service providers; and
- the importance of power system and network planning information to inform the competitive market and network regulation.

ERIG considers that the Western Australian government should examine the potential benefits from introducing arrangements for the efficient development of the South West Interconnected System (SWIS) based on the general principles recommended for the NEM.
ERIG Transmission Recommendations

ERIG considers that to develop an efficient, national transmission grid the following inter-related elements are required:

- improved locational signals to generators;
- stronger incentive framework for TNSP’s to better support outcomes in the electricity market; and
- an appropriate national mechanism for coordinating and integrating the national development of the power system.

These are the critical elements of a total reform package which can be expected, over time, to lead to significant benefits for Australia.

The proposed regime would not aim to remove all transmission constraints but would seek to drive the most efficient mix of well located generators and transmission investment to meet Australia’s future electricity needs. It would also seek to deliver at all times the most effective use of the existing transmission infrastructure and support trading in the competitive market.

Specific recommendations follow in each area as do a number of related supporting recommendations.

Locational signals to generators

The AEMC is currently conducting a review of congestion management in the NEM “to consider the requirement for and scope of enhanced trading arrangements in relation to constraint management and pricing”. The scope of that review needs to be widened to ensure the review addresses the need for efficiency of operations and dispatch in the short term and to drive efficient investment in the longer term.

An efficient regime in a competitive market context must, either explicitly or implicitly, price the cost of material congestion in the grid. In doing so, it will enhance the incentives to generators to invest in favourable locations relative to the grid.

The need for appropriate locational signals for generators is a pressing matter given the scope of new generation investment required to meet Australia’s growing needs.

**ERIG recommends that the AEMC congestion review should deliver a management regime which will both improve the efficiency of operations and dispatch in the short term and meet the allocative efficiency imperatives in the longer term.**

**ERIG recommends that the MCE review the terms of reference for the AEMC’s congestion management review to ensure consistency with the broader recommendations of ERIG and economic efficiency principles to ensure they have the scope to recommend such arrangements.**

**ERIG recommends that the MCE implement the recommended regime (and the appropriate transition measures) if it meets the criteria set out in the amended terms of reference by end 2008. The MCE should report to COAG on the review of the terms of reference and the outcomes of AEMC’s review within 6 months of the completion of the review.**
Improved incentives on TNSPs

The ACCC and now the AER have been developing performance measures and an incentive regime to apply to TNSPs for a number of years. The work has led to the publication during 2006 of valuable market impact measures but has fallen short of any improvements to the incentives applying.

ERIG supports the implementation of an initial incentive scheme as set out in the revised Rules (para 6A.7.4). Within that timeframe, the AER will not be able to develop as comprehensive a scheme as necessary to drive efficient outcomes and the new congestion management scheme and national planning arrangements will not be in place.

**ERIG recommends that the MCE require the AER to commit to a timetable for the development and implementation of a comprehensive incentive regime for TNSPs by end 2007.**

Improved national planning arrangements

ERIG believes that Australia must develop a more national approach in relation to energy network planning and investment, particularly in regard to transmission planning and investment. While our energy system needs to be enhanced to ensure a national approach is adopted where this enhances efficiency, its design needs to integrate ‘local’ requirements for reliability.

**ERIG recommends that a new national planning function be implemented to undertake transmission planning, to inform the market and the regulatory processes and to coordinate the efficient development of the national transmission network.**

**ERIG further recommends that the new national planning function be developed consistent with decision making, performance and investment accountability remaining with individual TNSPs in a manner which complements and informs the Regulatory Regime.**

The MCE should commission a review by the AEMC to detail the planning framework recommended by ERIG and to rewrite relevant sections of the law and the Rules including:

- detail the role and functions of the National Planner;
- implement rules requiring the National Planner to develop a National Transmission Network Development Plan (NTNDP) on an annual basis in accordance with network development objectives;
- develop Rules setting out the network development objectives under which the NTDP is developed based on integrating the two limbs of the current Regulatory Test;
- establish responsibilities for market participants and network service providers to provide information to the National Planner;
- put in place a formal mechanism for the involvement of industry participants and other stakeholders in the development of the NTNDP;
» link the role of the National Planner and the NTNDP to the regulatory regime and, in particular, to provide for these to inform the process for setting the ex-ante revenue cap;

» consider the development of any links between the congestion management regime and the national planner;

» introduce requirements for network service providers to undertake a Project Assessment and Consultation process on all major augmentations prior to final commitment. This process should ensure transparency around the decision to implement a particular solution including the assessment of non-network alternatives and demonstrate how the project is consistent with longer term development directions in the NTNDP; and

» consider the value of other Rule changes consequent to the introduction of the national planning process and the formation of the National Planner such as changes to any Planner of Last Resort role.

There would need to be consequential changes to the law and the Rules to integrate the new planning arrangements with existing requirements and to replace current provisions where appropriate.

The National Planner would replace the role of the IRPC, the NTDP should replace the ANTS and the new provisions would replace the current Regulatory Test arrangements.

National consistency of reliability standards

Chapter 3 of this report highlights the need for a consistent national approach to the national energy market. Where possible, the current plethora of different state government arrangements should be progressively examined and abolished in favour of consistent national measures.

This is a particular issue in the efficient development of the national transmission network where different reliability standards exist in each state. The differences exist in terms of form, function and interpretation.

**ERIG recommends that the Reliability Panel, which is formed under the AEMC, coordinate a national review to rewrite schedule 5.1 in the NER to provide a consistent national framework for Reliability Standards by end 2008. As part of this process, each state should review its requirements for individual connection points and publish them in that format.**

Formation of the National Planner under a reformed NEMMCO

The Market Structures chapter of this report recommends changes to NEMMCO’s governance. The proposed changes along with the inherent synergies make the reformed NEMMCO the appropriate body to undertake the new national planning function. The placement of this much expanded function in NEMMCO would require significant change in NEMMCO and would benefit from a set of specific objectives to guide its Board and management.
ERIG considers that the development of a ‘National Transmission Network Development Plan’ is not possible without understanding and analysing potential developments in the competitive sectors, the nature and location of likely generation investments and the location and growth of customer load. The planning requires a range of inputs and oversight from a range of industry participants and stakeholders is seen as essential to the plan’s quality.

ERIG recommends that the National Planner be formed under the umbrella of a reformed NEMMCO and that NEMMCO be provided with a clear set of objectives for the carriage of this function. ERIG also recommends provision be made for the formal involvement of industry representatives and stakeholders in the development of the National Transmission Network Development Plan.

Future review of national planning arrangements

The arrangements for the introduction of the new national planning regime depend upon the development and implementation of effective commercial incentives on generators and TNSPs.

The success of the regime needs to be reviewed within five years. This review should consider whether the incentive regime on TNSPs together with the coordination and advisory function of the National Planner have produced efficient outcomes or whether the role of the National Planner should be extended to provide it accountability for decision making and procurement of transmission services.

ERIG recommends that COAG review the arrangements for the introduction of the new national planning regime including the success of the regime. This review is to be completed within five years.

Recommendations for Western Australia

The arrangements described above relate specifically to the interconnected transmission grid covering Tasmania and the eastern states from South Australia to Queensland. Arrangements in Western Australia are different and have only been established for a relatively short period of time. However Western Australia operates a transmission network over a wide area and in a competitive market context. As such, the key principles for the efficient development of the Western Australian power system should be similar and ERIG has recommended exploring the potential to use national institutions for its development, operation and regulation. There are also potential advantages in applying the general principles recommended for the NEM in Western Australia in terms of:

» an appropriate congestion management regime in the short term forward market which is predictable and delivers productive efficiency;

» market based incentives for efficient service delivery by network service providers; and

» the importance of power system and network planning information to inform the competitive market and network regulation.

ERIG recommends that COAG request the Western Australian government examine the potential benefits from introducing arrangements for the efficient development of the SWIS based on the general principles recommended for the NEM.
7 Energy financial markets

ERIG’s findings and the way forward

Capital Markets and Investment
Key issues identified in a survey of investment respondents were:

Government ownership – investors see this as a significant impediment to efficient investment in the electricity sector in some states.

Retail competition – investors regard the implementation of full retail contestability in those states which have not already done so as being important to the development of an efficient financial market for energy. They see as particularly important the progressive removal of retail price caps or the progressive raising of price caps which in their view would stimulate competition and capital markets thereby lowering prices for end consumers.

Greenhouse and renewable energy – investors have indicated that they are factoring in a carbon pricing signal to their investment planning and decisions but are uncertain about its nature and timing. Investors view the existing range of government schemes and policies as fragmented and inefficient. This is argued to lead to a lack of liquidity and competition. This is brought to the attention of Governments.

Contract Trading in the NEM
Traded financial markets in energy are evolving in a generally positive way. There seems to be limited (if any) role for governments in traded financial markets per se other than ensuring expeditious improvements as required in the underlying spot market including as detailed herein.

Market liquidity has strengthened in the more visible markets (SFE and brokered OTC), partly at the expense of OTC bilateral trades. Because of the improvement in volumes of trade on the SFE, the aggregate volume of trading has trended up to about 1.3 times system demand. This healthy trend should be supported wherever possible when rule changes are considered. However, the liquidity and depth of the financial market varies across regions, across time and over products. There are specific gaps in the liquidity and depth of products in South Australia (and Tasmania), gaps in products to manage varying customer demand, and according to some participants, in short term products.

ERIG specifically notes the lack of depth apparent in trading in South Australia and Tasmanian energy financial markets. To enhance financial market trade and to deal with evolving trends in the market, such as vertical integration, it would be attractive to develop a mechanism in relation to South Australia and Tasmania to facilitate trading of these regions (without compromising existing arrangements and the basic NEM design integrity). ERIG has not had time to address this area in any detail, however, it is believed that such mechanisms may be practical. Similarly, the industry is encouraged to expedite the development of simplified tradable products to manage varying customer demand.
Vertical Integration

Financial market trading activity has increased in the face of the limited vertical integration which has occurred to date.

There is a need for a watching brief to monitor market developments over time to assess this impact.

The key strategic consideration is whether the market design and rules should evolve to better manage the evolution of the market to a lesser number of vertically integrated players. Strategic work to address this is proposed.

Institutional Arrangements and Market Design

There is a weakness in the development and implementation of key strategic policy in the energy market. Specific proposals are provided in this regard.

Industry should have a greater role in the oversight of NEMMCO’s market operations’ functions. In addition to reforming NEMMCO’s governance as proposed in Chapter 5, this could be achieved through the formation of a market operations panel to advise NEMMCO’s Board.

The energy-only design for the NEM has served the market well and should be retained. Furthermore, the material progress represented by the WEM is acknowledged and supported however some improvements are proposed for the mechanisms of the capacity market.

Inter and Intra Regional Trade

There is a need for refinement of intra-regional location signals to enhance efficiency. However, full nodal pricing should not be pursued as a solution in part because of the adverse effects this would have on energy financial markets.

Signals are also required for embedded generation (and firm demand side) within the distribution system or generators connected to transmission to receive the benefit of avoided transmission investment and, where relevant, credit for supporting transmission operations.

Some form of transmission pricing to signal the locations where generation is able to best support transmission should be considered.

The mechanisms supporting inter-regional trade are not working efficiently and adding to risk premiums in the market. The rationalisation of the Snowy Region is a key priority and will also enhance the effectiveness of financial markets.

There is also a need to improve the design of the instrument supporting interregional trade, particularly, the Settlement Residue Auction process by creating firmer transmission rights. The benefits of this measure, based on recent history, would be around $100 million per year for NEM customers.
Settlement of Spot and Contract Markets and Credit

Under the current NEM design, spot and contract markets are largely settled separately. This results in the duplication of credit requirements in the spot and contract markets. This situation increases systemic risk, creates timing differences, increases barriers to entry and is increasingly important with the privatisation of retail in Queensland.

Proposals are presented for advancing the integration of contract and spot electricity markets.

The removal of barriers to the increased use of SFE settlement to offset spot market settlement is also proposed.

Demand Response

While some progress has been made, the demand side in the NEM is relatively inactive compared with its potential. Achieving its potential would drive major benefits in the NEM.

To achieve these benefits, further work is required to develop a framework whereby customers, market participants and intermediaries can benefit from demand side activity.

In the large customer segment, while progress has been only fair, there seems to be little basis for a policy response.

The commitments made by state and territory governments to remove retail price controls will be helpful when implemented in supporting cost reflective prices and demand response.

The work program of the MCE on demand side response and the progressive rollout of electricity smart meters from 2007 provides a further building block and is to be encouraged. However, smart meters alone would not be sufficient to create a demand side response.

The development of automated DSM for small and medium customers is probably required to further encourage DSM but may not develop without initial sponsorship by governments and supportive changes in the institutional arrangements to ensure that market signals can work in practice.

Government and Regulatory Issues

There are a number of areas where the Commonwealth, through ASIC, could consider action to better support and remove barriers to the development of more efficient financial markets in electricity and gas, thereby fostering reduced risk premiums.

The removal of ETEF in NSW in accordance with the published timetable, as well as the removal of LEP in Queensland would enhance financial market trade.
Gas Financial Markets

The Gas Market Leaders Group recommendations offer worthwhile progress and are generally supported.

The establishment of a gas spot market and a National Gas Market Operator (with ultimately a National Energy Market Operator) is strongly supported.

Greater standardisation of market structures, market processes, pipeline access and supply points for pricing across the market is required to enhance gas financial trade. This is becoming more important given the increasing trend towards gas fired generation and gas retail competition in the NEM.

Further work is required to assess the upstream areas of acreage management and joint marketing.

Introduction

ERIG has been asked to examine

“any measures that may be necessary to ensuring there are transparent and effective financial markets to support energy markets”.

Transparent and effective energy financial markets act to support the underlying energy market by providing instruments for market participants to manage risks and by providing signals for investment. Parer (2002) noted:

“Financial markets are integral to the ongoing viability of the gross pool model adopted for the NEM and to the overall success of the electricity reform program”.

Australia’s energy financial markets comprise:

» capital markets – which provide equity and debt to support investment and drive the efficient structuring of business;

» spot markets – which support efficient dispatch; and

» contract markets – which provide tools for price certainty and risk management.

ERIG has focused on electricity and to a lesser extent, gas markets.

In terms of electricity, the primary focus has been the NEM (the interconnected states of Queensland, NSW, Victoria, SA and Tasmania). However limited commentary is also provided in regard to the newly created electricity market in WA.

This chapter outlines the key findings and considerations in this area of ERIG’s terms of reference. To analyse some of these issues in more detail, KPMG was engaged to assist ERIG in its deliberations.
The issues identified

Overall the evaluation of the NEM is positive in relation to financial markets, notwithstanding that there are areas where useful reform should proceed. Gas financial markets by contrast are immature, lacking effective spot markets (except in Victoria) and generally lacking financial markets. In addition there are material impediments to the development of trading in gas.

Key strategic issues affecting energy financial markets

A number of key strategic issues have been identified by ERIG as follows:

- capital markets and the investment environment;
- contract trading in the NEM and vertical integration;
- institutional arrangements, particularly regarding the strategic development of the market;
- design of the market, particularly the single energy market with no separate capacity market;
- inter and Intra-regional trade:
  - Intra-regional location signals affecting investment in generation within a region;
  - Inter-regional trade. There are material inefficiencies in the operation of financial markets in relation to interstate trade, with additional unique issues surrounding the Snowy region;
- settlement of the spot and contract markets and credit;
- short term forward market;
- the participation of the demand side in the market which faces significant barriers;
- the role of Governments as owners and regulators; and
- The development of the gas market to support contemporary policy objectives including retail competition and gas fired generation in a competitive electricity market.

These issues are addressed in detail below.

Capital markets and investment

Capital markets play a central role in the energy sector. They provide investment capital to support the development of assets and impose a discipline which rewards operating efficiency and efficient investment, and conversely provide penalties for poor investments and inefficiency.
Stakeholder views on investment impediments

To better understand if capital markets are performing their role in investment in the energy sector, and in particular in the upstream and downstream electricity and gas markets, ERIG engaged KPMG to survey potential market investors. KPMG interviewed twenty existing and potential investors including the major integrated players, independent generators/producers and retailers and a number of major commercial and investment banks. The key focus of this survey was to identify any impediments to capital investment in the energy sector.

Based on KPMG’s work, ERIG has concluded that energy capital markets are generally working well, but could operate more efficiently if certain impediments to efficient investment are removed. In general, when considering both electricity and gas, and taking a national view, considerable investment is occurring and more is proposed. However, KPMG notes that there is a basis for some concern, particularly as new base-load electricity capacity becomes necessary.

KPMG notes investor concerns about impediments to efficient investment in the energy sector, and in the electricity sector in particular. Investors believe that the three key impediments to more efficient investment are:

- government ownership of energy businesses;
- residual electricity price regulation at the wholesale and retail levels; and
- government policy in regard to greenhouse gas emissions and renewable energy.

Investors reported to KPMG that they do not see major impediments to investment in the areas of market rules, market access and market performance, although improvements could be instituted.

The widespread view across the KPMG study (and supported by submission comments and industry consultation undertaken by ERIG) is that the energy market works ‘pretty well’, and better than similar markets overseas. However, submissions and industry consultations consistently noted that the removal of impediments relating to Government ownership and Government price regulation should be priorities. In relation to greenhouse and renewable energy, investors were virtually unanimous in their contention that a nationally consistent approach including a national carbon pricing signal is required. KPMG notes that available evidence supports investors’ views identified in their study sample on the impediments to more efficient investment.

Findings on capital markets and investment

As noted previously, three key impediments were identified by KPMG and reinforced through industry consultation: Government ownership, price regulation and government greenhouse and renewable policies. The common theme of the three key impediments identified is the role of regulatory uncertainty created by government policy.

As detailed in the KPMG study, investors believe that this regulatory uncertainty distorts investment decisions by:

- increasing uncertainty;
- making it more difficult to value project risks; and
reinforcing the strengths of those in the strongest position to manage the associated uncertainties (i.e. larger, vertically integrated players).

Noting this common theme, the three key impediments identified in the KPMG study are discussed below.

Government ownership

Government investment in the energy market is a crucial impediment to the efficiency of capital markets. Government owned businesses in the energy sector are generally not subject to the full disciplines of capital markets.

As detailed in the KPMG study, investors consider that government ownership impedes investment decisions by:

- producing premature investment; and, as a result,
- deferring or crowding out investment the private sector otherwise would undertake;
- increasing asymmetric risks (e.g. asset stranding);
- distorting price signals in the market through investment and operating decisions; and
- generally discouraging new entry because investors typically have an aversion to ‘competing’ with government owned businesses and will often allocate capital accordingly.

In particular, the KPMG survey contends that investors believe government ownership is most likely to impede efficient investment if:

- governments are proposing new investment;
- government owned businesses are making inefficient operating and pricing decisions; or
- there is a risk that governments might propose new investment at a later date.

Further discussion on ERIG’s concerns regarding government ownership is contained in Chapter 5.

Government regulation of pricing

Government regulation of pricing is a significant impediment to the efficiency of capital markets. As evidenced through the KPMG study, investors maintain that retail price regulation:

- Distorts wholesale and retail markets;
- Discourages new entry; and
- Impedes retail competition, thus undermining its ‘effectiveness’ (e.g. making prices less cost reflective and thus undermining demand side response).

This message is best articulated in the ERAA response to the ERIG discussion paper which notes:
“Ongoing price regulation in retail energy markets prevents effective competition. Tariffs set below cost-reflective levels, act as a barrier to new entrants and the introduction of innovative pricing structures. Price regulation, with its inherent cross subsidies, distorts efficient market outcomes and prevents appropriate price signals reaching customers which would otherwise influence their behaviour and consumption”.

Further discussion on ERIG’s concerns regarding government price regulation is contained in Chapter 5.

Greenhouse gas emissions and renewable energy government policies

Investors view the proliferation of existing government greenhouse and renewable policies and schemes as fragmented and inefficient. To demonstrate this policy fragmentation, KPMG notes that as at March 2006, the Federal Government claimed to have over eighty policy measures in place to combat climate change. In addition, the KPMG study notes the multitude of state and territory policies that overlap with other jurisdictional schemes. For those schemes amenable to trading, this is argued to lead to a lack of liquidity.

ERIG notes industry views that the current policy uncertainty in relation to greenhouse gas emissions is a major impediment to new investment. Investors are factoring in a future carbon pricing signal, but approaches differ between investors in terms of the nature and timing of carbon pricing. As a result of these risks, investment decisions are being distorted in terms of the location chosen (e.g. a scheme may attract an investment to a sub-optimal location) and the technology utilised in the investment (e.g. a particular technology or fuel is advantaged).

Investors argue that ‘investing in electricity generation at the moment is akin to gambling on the political environment which is no basis upon which to make investment decisions.’ Critically, the KPMG study notes that the single largest impediment to investment in new base-load plant is the current uncertainty regarding greenhouse gas emissions policy. Impacts recognised by KPMG as a result of the current policy environment are that:

- new base load capacity is likely to come on line later than it otherwise would and/or be built by governments;
- incumbency advantages of the major players in the industry will be exacerbated; and
- parties may be more likely to invest offshore in the absence of greater certainty in regard to greenhouse gas policy in Australia.

To address this situation, KPMG suggests federal and state governments need to work together to develop a long term carbon price signal and coordination of renewable energy programs. The recently announced carbon trading enquiry by the Prime Minister may draw upon, and investigate, some of these issues in more depth.
ERIG finding and recommendation

Capital Markets and Investment

» Government ownership – investors see this as a significant impediment to efficient investment in the electricity sector in some states.

» Retail competition – investors regard the implementation of full retail contestability in those states which have not already done so as being important to the development of an efficient financial market for energy. They see as particularly important the progressive removal of retail price caps or the progressive raising of price caps which in their view would stimulate competition and capital markets thereby lowering prices for end consumers.

» Greenhouse and renewable energy – investors have indicated that they are factoring in a carbon pricing signal to their investment planning and decisions but are uncertain about its nature and timing. Investors view the existing fragmented government schemes and policies as fragmented and inefficient. This is argued to lead to a lack of liquidity and competition. This is brought to the attention of Governments.

ERIG recommends that COAG note that many existing participants in the market and a range of potential investors raised concerns with both the uncertainty about government policy on greenhouse gas emissions and the lack of a carbon pricing signal. The disparate range of State and Commonwealth greenhouse schemes also impose costs on participants and cause inefficiencies in the choice of fuels, plant and location and timing of investment and increased risk premiums. Development of greenhouse policy is outside ERIG’s terms of reference, however the issue has been unavoidable in our work and consultation and is brought to COAG’s attention for its consideration because of its adverse effects on market efficiency (noting also the comments under greenhouse gas abatement policy in chapter 5).

Contract trading in the NEM

The traded market for electricity includes the spot market and the forward market. This section analyses the forward market where contract trading occurs either direct over the counter (Direct OTC), brokered over the counter (Brokered OTC) and on the listed products trading on the Sydney Futures Exchange (SFE).

A transparent, effective and efficient contract traded market provides instruments for participants to manage their exposure to market risks and also provides price signals for new entry and investment.
Westpac states that:

“Spot and financial markets need to be considered as a single entity. The spot market exists primarily to provide a reference price to settle financial contracts against and as such is a secondary market. The primary market is in forward and futures contracts … it not only provides the ability to hedge pool exposure, it also gives a reference price without which end-use customers and regulators have no indication of the potential wholesale cost of electricity”.

ERIG has been asked to examine measures necessary to ensuring there are transparent and effective financial markets to support energy markets.

Stakeholder views on liquidity and depth in contract trading

The general view from submissions is that trading in energy financial markets is evolving satisfactorily. Evidence to support this proposition relates to the increasing levels of trade that are occurring in the over the counter and exchange traded market on the Sydney Futures Exchange (SFE). Westpac, Origin, Snowy Hydro, Stanwell, NGF and AGL maintain that liquidity and depth has increased significantly and sufficiently since Parer (2002), providing effective support to a competitive and efficient spot market. Furthermore, the increasing involvement of financial intermediaries provides positive evidence of an evolving market.

Contrary to this view, Gallaugher believes that the financial market lacks sufficient liquidity and transparency to be described as the well functioning market that would help deliver economically efficient outcomes overall in the electricity sector. Other participants point to the absence of liquidity in some regions and particularly peaking products, and express serious concern about the impact of the trend towards vertical integration. According to the Australian Stock Exchange (ASX), the regionalised design of the NEM implies there are periods of illiquidity when there is a concentration of ownership.

The importance of the price discovery process offered by the SFE is raised by the EUAA and Origin. The ERAA points to the Price Waterhouse Coopers analysis of liquidity in the NEM to show that liquidity is sufficient and the ASX provides further analysis of the liquidity in the NEM.

Analysis

The majority of contract trading in the NEM occurs in the Direct OTC and Brokered OTC markets. Figure 16 provides a comparison of the OTC instruments traded in the NEM provided by the Australian Financial Markets Association (AFMA) annual survey:
18 Traded OTC instruments in the NEM

Figure 18 shows that swaps are by far the most traded instruments in the NEM. Figure 19 shows the annual turnover of OTC products by region using AFMA’s annual survey:

19 Turnover of OTC instruments by region, 2000 – 2005

The level of trade in the OTC market has not varied significantly over the past five years. South Australia has relatively low levels of trade in the OTC market. Figure 20 shows the turnover of OTC trade compared to NEM system load:
Trade in the OTC market tracks spot market trade closely and this has been a consistent trend for several years.

In contrast to the constant level of trade over time in the OTC market, trade in electricity related instruments listed on the SFE has increased substantially since Parer (2002). Figure 21 shows the annual volumes of trade on the SFE in each region 1997 - 2006:

21 Annual traded volumes on SFE, 1997 – 2006
There are several reasons for the increase in trade on the SFE. In 2002, the SFE reconfigured its product offering, increasing its attractiveness. There is also now an increased number of financial intermediaries present in the market compared to the number present when Parer (2002) analysed the market. Credit concerns have also driven the development of futures. This is because the margining associated with futures limits potential losses in the event of insolvency.

Taken together, these figures suggest that combined OTC and SFE trade turnover is about one and a third times spot market turnover.

Figure 22 shows the tenor of trade on the SFE. This shows that trading is focused on the first 2 to 3 years with limited longer term liquidity.

22 Base futures curve

Figure 23 shows a comparison of traded volumes in exchange traded instruments across several commodities and different electricity markets.

23 Comparison of trade in exchange traded commodities
This shows that electricity trade on the SFE is well below best practice liquidity as represented by Nordpool in the energy sector and other well established commodity markets. Furthermore, when available OTC data is included, the traded volumes are still well below those exhibited by Nordpool. However, it needs to be noted that these markets are significantly different from the NEM.

**ERIG findings and recommendation**

**Contract Trading in the NEM**

Traded financial markets in energy are evolving in a generally positive way.

- There seems to be limited (if any) role for governments in traded financial markets per se other than ensuring expeditious improvements as required in the underlying spot market including as detailed below.

- Market liquidity has strengthened in the more visible markets (SFE and brokered OTC), partly at the expense of OTC bilateral trades. Because of the improvement in volumes of trade on the SFE, the aggregate volume of trading has trended up to about 1.3 times system demand. This healthy trend should be supported wherever possible when rule changes are considered. However, the liquidity and depth of the financial market varies across regions, across time and over products. There are specific gaps in the liquidity and depth of products in South Australia (and Tasmania), gaps in products to manage varying customer demand, and according to some participants, in short term products.

- ERIG specifically notes the lack of depth apparent in trading in South Australia and Tasmanian energy financial markets. To enhance financial market trade and to deal with evolving trends in the market, such as vertical integration, it would be attractive to develop a mechanism in relation to South Australia and Tasmania to facilitate trading of these regions (without compromising existing arrangements and the basic NEM design integrity). ERIG has not had time to address this area in any detail, however, it is believed that such mechanisms may be practical. A possible mechanism might be for generators (e.g. in SA) to forward sell transmission rights, but the details would have to be formulated and there may be other options. Similarly, the industry is encouraged to expedite the development of simplified tradable products to manage varying customer demand.

**ERIG recommends that the MCE sponsor a strategic study on the potential for simplifying key aspects of trading across the NEM (without compromising the basic NEM design). Such work would include additional mechanisms to support interstate trade and the simplification of trading into SA and Tasmania.**
Vertical integration

Vertical integration in the energy sector involves the combination of retailing and generation for electricity or retailing and production for gas. The issue of vertical integration is discussed in depth in Chapter 5 of this report. This section is focused specifically on the effect of vertical integration on the liquidity and depth of traded markets.

Stakeholder views on the impact of vertical integration on financial market liquidity

Energy Australia, Elia, MEU, Westpac, AER and the ASX assert that vertical integration lowers liquidity in the financial market, reduces available hedge cover and restricts forward price discovery. Conversely, AGL and Snowy Hydro point out that the volume of contracts traded has significantly increased in a period where vertical integration across the market has increased. TRUenergy agrees that vertical integration has not impacted on financial market liquidity to date.

A number of stakeholders contend that a key motivation for vertical integration in the energy sector is the lack of short term financial market liquidity available e.g. 1-2 days out. As such, it is argued that the ultimate hedge is the dispatch rights for effective control of a peaking generator e.g. physical option availability. Vertical integration is therefore argued to be both a cause and response to the lack of liquidity in certain financial markets.

Stakeholders also note that trading volumes are driven by factors outside of the number of participants e.g. participant strategy, credit, and the degree of imbalance in positions. The interplay of these factors further impacts on market consolidation.

Finally, the ASX suggests that it is difficult to determine the impact of vertical integration but notes that the high levels of vertical integration experienced in New Zealand and the United Kingdom are aligned with low liquidity. Furthermore, there has been a reduction in the liquidity for caps in Victoria since AGL’s acquisition of Southern Hydro.

The impact of vertical integration on financial market liquidity

The key factors driving vertical integration are:

» cost of capital – integrated players have a lower cost of capital as risks are more readily managed;

» trading risks and trading strategies offer more opportunities for adding profitability when the party owns both generation and retail; and

» accounting standards – option related peaking derivatives are marked to market and movements appear as non cash items in the P&L, while physical peaking generation is not marked to market.

ERIG notes that it is difficult to isolate the specific impact of vertical integration on financial market liquidity. The fact that NEM financial market volumes have remained constant or increased, rather than declined in the face of increased vertical integration could simply be a reflection of the maturing of financial markets in Australia. This market maturity could be masking negative impacts on financial flows arising from physical market hedges.
It is considered that if the market were to evolve, as expected by many participants, to 4-6 major players owning both generation and retail, financial market liquidity would be reduced. The formation of this view has been assisted by observations of the UK market where the market has consolidated to six vertically integrated players and financial market liquidity has declined. Figure 24 shows the proportion of energy generated by vertically integrated entities in the NEM:

![Figure 24 Proportion of generation by retailers](image)

Figure 24 shows that across the NEM, vertical integration is still only modest. Arguably however ETEF could be regarded as de facto vertical integration. If the effect of ETEF were included, the level of effective ‘vertical integration’ would be higher. Although figure 22 uses energy generated to determine the extent of vertical integration, the extent of vertical integration would still be modest if capacity is used as the measure, albeit the extent would be higher.

The business drivers for vertical integration are strong and likely to continue. The key issue is not the trend towards national vertically integrated players, rather it is whether the market design should develop and change and become more national to better deal with these trends and facilitate the persistence of financial markets in the face of the possible challenge of vertical integration.

Vertical integration is further discussed in chapter 5.

**ERIG findings**

**Vertical Integration**

- Financial market trading activity has increased in the face of the limited vertical integration which has occurred to date.
- There is a need for a watching brief to monitor market developments over time to assess this impact.
- The key strategic consideration is whether the market design and rules should evolve to better manage the evolution of the market to a lesser number of vertically integrated players, and this has been addressed above.
Institutional arrangements and market design

Institutional arrangements

Chapter 5 details the key institutional arrangements in the gas and electricity markets. It also details the principles surrounding the allocation of roles and governance. This section addresses the specific issues in relation to financial markets.

The key areas of interest to gas and electricity financial markets are:

- strategic market development and policy,
- NEMMCO and its role in settlement, and
- market design.

These are addressed below.

Strategic market development and policy

The current responsibility for this function lies with the MCE (and COAG). MCE’s approach has been to identify strategic issues and to commission ad hoc analysis using consultants, and groups like the GMLG and other expert groups. This approach has had some successes. The weaknesses seem to be:

- a somewhat ad hoc approach to the identification of key issues. However some excellent and important issues have been addressed (e.g. DSM, gas market);
- implementation—execution of agreed plans or policies lacks a well defined process; and
- MCE is a rather unwieldy group leading to unclear accountability and delays.

ERIG sees the key strategic issues to be addressed, as detailed elsewhere in this Chapter, are:

- development of policy and market design to deal with the evolving consolidation of ownership and vertical integration;
- development of the policy framework surrounding DSM;
- development of the gas market, eventually into a market much more like electricity;
- development of the instruments supporting inter-regional trade and intra-regional location signals;
- development of a net settlement system; and
- resolution of policy in relation to greenhouse and renewable energy.

The alternative ways in which policy could be developed more reliably include:

- expanding the role of the AEMC (See also Chapter 5);
- having a new small strategic group responsible for managing policy development and driving implementation;
- greater use of expert groups like ERIG and GMLG (perhaps in addition to the two alternatives above); and
using the Productivity Commission to undertake independent reviews of the energy industry.

**NEMMCO – its role in settlement**

A range of issues relevant to the governance of NEMMCO are discussed in chapter 5. The recommendation of ERIG outlined there is that NEMMCO’s governance should be improved by providing for more independence in relation to Board appointments, and industry involvement in those appointments. The reform of NEMMCO’s governance would provide investors with greater confidence and give NEMMCO stronger incentives to provide efficient service delivery.

The reforms proposed give governments a significant role in the appointment of NEMMCO’s Board and control of its performance. This is justified as the jurisdictions jointly own NEMMCO and bear risks from any under-performance. Whilst a significant ongoing role for governments in the appointment of the NEMMCO Board is appropriate, ERIG considers that NEMMCO’s market operations function should have a greater level of industry control because:

> "market participants have a substantial exposure to the effective delivery of market operations, and a common interest in ensuring effective and efficient conduct of the market operation role" (Firecone report to ERIG, "NEMMCO: Governance Arrangements page vi).

In its report to ERIG, Firecone suggested that this could be achieved by establishing a ‘Market Operations Panel’ which would oversee the market operation services. This Panel would be drawn from industry, on a representative basis, and be chaired by a representative of NEMMCO’s main Board. The Panel would consider how best to procure NEMMCO’s market operation services on an efficient and effective basis whether from NEMMCO, other service providers, or some combination of the two.

The Panel could be formed on a representative basis by grouping participants into categories such as generators, retailers and customers. Participants in each group could nominate a representative to be on the Panel by voting where necessary. Selection could be on the basis of one vote for each registered participant in the relevant group. Firecone’s advice suggests that the development of these voting rules is likely to be complex, and would require time and consultation with industry.

The introduction of a ‘Market Operations Panel’ representing the industry in the management of the market operations functions of NEMMCO would further improve its service culture. As outlined by Firecone:

> "The costs of NEMMCO’s market operations role are recovered through participant fees, and are sensitive for market participants. However, it would not be worth implementing a change such as this simply for reasons of cost minimisation. Rather, the focus would be to ensure a responsive, participant-driven service. The quality of service, and the potential for dynamism and innovation, would be the key rationale."

The Market Operations Panel therefore needs to have some level of control over areas prescribed for its oversight rather than simply acting as an advisory panel. ERIG considers though that the NEMMCO Board should still retain ultimate responsibility and, in particular, be responsible for ensuring that NEMMCO met its obligations under the NEL and that no action of the Panel impeded market entry without good reason. This might be achieved by requiring
the NEMMCO Board to fully consider recommendations of the Panel and either accept or reject those recommendations and with NEMMCO able to over-ride the Panel, but only by direction. Where a recommendation was rejected, the Board would be obliged to provide its reasoning back to the Panel and the existing arrangements would continue in place.

Implementing the proposed governance reforms to NEMMCO and the formation of a Market Operations Panel would require further work on:

- the appointment processes for the Panel;
- the identification of role and functions of the Panel;
- the relationship between the Panel and the main NEMMCO Board; and
- the legal and other arrangements to establish the Panel and its roles and functions.

As highlighted by Firecone, any changes to the governance arrangements for NEMMCO are likely to be sensitive, given the strong interest by both governments and market participants in ensuring that the functions established for NEMMCO under the NEL are undertaken effectively and efficiently. Work therefore needs to be commissioned and consultation undertaken to detail these changes to the governance arrangements proposed by ERIG.

In addition to the immediate benefits available to the electricity market, these proposals could also facilitate future arrangements in gas, perhaps through the formation of a separate Gas Market Operations Panel in the future.

Market Design

The NEM design has been a successful reform, which has driven substantial efficiencies. Key issues discussed by participants in this area were:

- the introduction of a capacity market;
- the capacity market in WA;
- inefficiency in inter-regional trade (discussed in a later section);
- intra-regional location signals (discussed in a later section); and
- settlement of the spot and contract markets (discussed in a later section).

Capacity versus energy markets

Some participants have argued that introducing a capacity market would support market efficiency and investment.

User groups and some generator representatives have suggested that the observed wholesale spot price volatility within the NEM should lead ERIG to consider alternative market design models to reduce that volatility. Several market participants pointed to the need for major reform, such as the introduction of a capacity market, but most commentary focused on refinements to the basic NEM design.

Electricity markets of different designs operate in all restructured markets around the world. Many of these designs have common elements. However, all markets coalesce around one of two distinct design choices:
‘energy only markets’ – where payment is made only for electricity actually supplied; versus
‘capacity markets’ – where payment is made for both electricity supplied and for capacity that is available when needed.

In Australia, both of these market designs are in use. The NEM is an energy only market, whilst the WEM is a capacity market.

At the centre of the debate over both market designs is the requirement for regulatory intervention in defining and pursuing a target level of installed capacity sufficient to meet demand, with each design differing in the payment mechanism for meeting the fixed costs of the required capacity.

In an energy only market, the target level of installed capacity is implicit in the regulatory settings of the ‘Unserved Energy’ reliability standard and VoLL. Under this design, the risk associated with extremely high prices supports the development of insurance contracts and physical capacity.

In a capacity market, capacity obligations are administered by the market operator and the payment mechanism includes a ‘pay for performance’ measure to ensure availability at the time it is most needed. In the associated energy market, prices are capped at a level lower than that of any ‘energy only’ market because some of the recovery of fixed costs occurs through the capacity market.

In principle, when designed appropriately, efficiently operating ‘energy only’ or capacity markets should deliver similar outcomes in terms of overall economic efficiency, installed capacity levels, and the mix of installed technologies. Under both market designs, where competition is effective, the result should be prices being close to their efficient level.

Whilst there is an increasing amount of literature assessing both energy only and capacity markets worldwide and their efficiency and effectiveness in bringing forward investment, there is limited empirical evidence that favours one design over the other.

Relating the debate back to ERIG’s terms of reference, and focussing on practical considerations, it seems that the most useful contribution that ERIG can make to this debate at this stage is to concentrate on practical recommendations that would make both the NEM and the WEM operate more efficiently. Implementation of any such recommendations may reduce if not eliminate real-world differences in market outcomes between the two market design models. That may obviate the need to change models after considerable resources have been invested in putting them in place in different regions of Australia.

The NEM has been operating for some time as an energy only market. There is a widely held view that the NEM—so far—has operated reasonably well, delivering new capacity as required. Generally this view is supported by ERIG.

At this time no evidence has been put forward to ERIG to establish that the NEM—the energy only market—is materially deficient. The concern that investment will not come forward in the energy only market has not been substantiated (though there is still debate, see also Chapter 5) and therefore ERIG can see no reason to further investigate the merits of an alternative market design at this stage. ERIG also notes that this issue alone, even were it to warrant further investigation at this stage, would need to be the subject of an
intensive and detailed investigation which is well beyond the time available for ERIG’s deliberations. Further, any consideration of a change in the design of the market would have a material impact on investment decisions, and the uncertainty created may adversely impact investment until the matter had been finalised.

Western Australia - WEM

The Wholesale Energy Market (WEM)—a capacity market—has only commenced operating relatively recently. The capacity trading component of the WEM has been operating for two years, whilst the energy trading component commenced operations on 21 September 2006. The IMO operates both the capacity and energy markets. Time will be required to evaluate how effectively it operates.

In the WEM the required reserve margin is set by the IMO. The IMO sets the price for capacity for each year (with a lead time of 2 years) for any capacity which is not traded bilaterally and if there is a surplus of capacity offered to the market. If the capacity offered is less than that required by the IMO, the price for capacity is set by the market tendering process.

ERIG nonetheless notes, even at this early stage, that a concern is emerging regarding the effectiveness of a key element of the design – the capacity deficiency signal.

As noted earlier, for a capacity market to operate effectively, the design elements require a ‘pay for performance’ measure to ensure availability at the time it is most needed.

The capacity deficiency signal in this market is weak – there is a seasonal profile, but the driver for generation (or demand side) to perform at critical times is low, orders of magnitude less than in the NEM.

The key issues are:

» the design of the capacity market;

» the setting of the reserve margin administratively rather than by the use of market forces;

» the relatively weak price signal or penalty associated with plant not being available at critical times;

» structural issues where there is essentially a single generator and a single retailer; and

» the many functions undertaken by the IMO. (See Chapter 5).

It is understood that in WA, with a smaller market and concerns over the market power of Verve Energy, that a different market formulation is not unreasonable. It is also acknowledged that the WEM represents a major reform which clearly provides a basis for new entry. By constraining Verve Energy from investment, the signal is clear for the private sector to invest. However, as the private sector invests capital under the existing rules, it will become more difficult to refine the market design in material ways.

Despite the separation of WA and the different market design, there seems little reason to duplicate institutions in WA and the NEM. Cost savings and efficiencies should be available by combining functions. In addition harmonisation should be pursued where practical.
ERIG findings and recommendations

Institutional Arrangements and Market Design

There is a weakness in the development and implementation of key strategic policy which has been elaborated in some detail.

ERIG recommends that the MCE develop a greater strategic and implementation capability, initially to address the issues identified in this Report. (See also recommendations 2.1 and 2.3.)

This might include:

» Empowering the AEMC to take a more pro-active role in the development of market rules, but perhaps take a lesser role in more strategic market reviews,

» Establishing a new strategic group (reporting to MCE) to manage the development of strategic policy, and

» Increasing the use of expert groups where specific expertise, knowledge or industry involvement is required.

ERIG recommends that the Industry should have a greater role in the oversight of a reformed NEMMCO’s market operations functions through the formation of a Market Operations Panel, to oversee the specification and procurement of market operations functions. The MCE should commission further work to detail and implement reforms to NEMMCO in consultation with stakeholders. (See also recommendation 3.5)

ERIG recommends that the ‘energy only’ design of the NEM be retained.

The material progress represented by the WEM is acknowledged and supported.

ERIG recommends that

» COAG negotiate with the WA Government with a view to the AEMC taking responsibility for the market rules of the WEM before the end of 2008, and

» COAG request the WA Government to instruct the IMO to improve the workings of the capacity mechanism by strengthening significantly the capacity signal in the WEM and making it more market orientated. ERIG sees no reason why this could not be achieved within 12 months. (See also recommendations 3.6 and 5.7).
Inter and intra-regional trade

Inter-regional trade across the NEM is an important feature of the market. It provides: competition; inter-regional shared security; load diversification; power transfers from low cost to high cost regions; and, where signals emerge, investment incentives for generation across the regions.

Congestion arises when parts of the network become fully loaded and limit the volume of generation that can be dispatched in certain locations on the network. Congestion, or volume risk, is a major source of trading risk. In the NEM regional design, congestion is priced only at the regional boundary leading to price separation across regional boundaries with electricity generally flowing from low to high priced regions. Intra-regional congestion, however, is not priced in the regional design of the NEM.

Both inter-regional and intra-regional congestion can influence both inter and intra-regional flows across the NEM. This has implications for inter-regional trade as the volume risk associated with intra-regional congestion can manifest itself with the price risk of inter-regional congestion. This relationship is discussed in chapter 6 which discusses the role that transmission incentives and location pricing play in increasing trade across the NEM.

This section addresses the risk of trading across the NEM from a financial markets perspective. It analyses:

» Intra-regional trade and location signals.

» Inter-regional trade including:

  – Analysing the performance of inter-connector flows and the impact of this performance on the instruments used to support inter-regional trade,

  – Analysing the potential sources of volume risk across inter-connectors particularly generator bidding behaviour, the Snowy region, transmission constraints, transmission operation, and

  – Investigating the potential to improve the instruments used in the management of trading risk, including managing generator behaviour, the Snowy region design, and the design of the settlement residue auctions.

Intra-regional trade and location signals

In addition to the risks of inter-regional trade, generators also face intra-regional trade risks from trading across intra-regional constraints. There are also weak signals driving investment in areas which would support the grid.

Intra-regional trading issues are:

» access of generators to the transmission network. This is an important issue, but has not been considered in sufficient depth for conclusions to be drawn; and

» pricing signals which encourage generation (and where applicable, customers) to locate efficiently and operate to support the network.
These issues are canvassed also in Chapter 6. This section focuses on the effect of intra-regional location signals on financial markets (capital, contract and spot).

**Stakeholder views on intra-regional trade and location signals**

Network congestion is noted by Ergon and Verve as a key concern for generators as it increases trading risk. This has the potential to provide network owners and operators with clearer market signals to support more efficient risk mitigation.

Energy Australia and the ERAA note that the AEMC Congestion Management Review has the potential to provide some useful improvements to the market design which should be allowed to run its course. A clear view across submissions is that rather than introducing full nodal pricing signals or firm transmission rights, there should be improved integration between the transmission network services and the electricity market.

TRUenergy supports improved intra-regional pricing signals to enhance generator location decisions, as well as aligning generator incentives with maximising inter-connector flows when the market values these most. Along with consumer groups, TRUenergy is also supportive of improved incentives for regulated entities to contract with embedded generators to capture the benefits of avoided TUOS, or avoided transmission investment.

**Analysis of intra-regional trade and location signals**

Within a region, generators locate for a variety of reasons including the cost of accessing the distribution and transmission system and the loss factor at the relevant part of the network. The broader transmission system benefits or costs of a choice of location are not reflected to the generator.

In addition to the initial location of a generator, there may also be a role for the generator (or demand side) in supporting the operation of the transmission network, either supporting capacity or supporting flows. Generation (and in theory demand side) could contract to operate to support the transmission network. For example, generators could contract to operate at peak times in summer. In practice there are examples of such network support contracts, but so far they have had limited application.

There is a case for a pricing regime which rewards generators for locating and operating to support the transmission network.

An alternative which has been suggested is full, or more finely grained nodal pricing than currently exists. Another alternative would be simplified transmission pricing arrangement whereby generators would be paid (or perhaps be penalised) for locating within particular zones. These alternatives are discussed further below.

Nodal pricing involves establishing fined grained prices by location, thereby providing an energy market signal for generation to locate. In practice it is not so simple:

- nodal pricing creates many prices which can separate if constraints occur making the market much more complex;
- it can only be introduced sensibly if firm transmission rights are simultaneously introduced;
it changes the price to every player in the market, and disrupts existing contracts, creating an element of sovereign risk;

it impedes competition as there would many local monopolies or oligopolies; and

it seriously disrupts financial markets which thrive on volume and liquidity – such markets work better with simplification rather than more complexity.

The signals which nodal pricing would create, help little in driving the location of generation – the mere establishment of generation in response to high nodal price may remove that high nodal price. A longer term signal which can be captured by the generator at least for a period is needed to reflect the capital cost saving in transmission investment (where this applies).

With a transmission pricing regime (or with the use of constraint support contracts), the problems of nodal pricing can be avoided. Insufficient analysis has been done to reach firm recommendations, however these approaches are suggested for consideration:

- for embedded generation and demand side: these participants could be offered a distribution payment for the service they provide in replacing the need for transmission at peak times. For example: the payment might be (say) 80-90% of TUOS charges with a penalty which might reduce the payment to zero depending on performance at peak times;

- for generation connecting to the transmission system: a zonal price (or penalty) could be applied for a fixed period reflecting the system cost or benefit of locating in that zone; and

- there is also a case for greater use of network support contracts where a generator can operate to support the transmission system.

ERIG notes the current absence of intra-regional location signals and the difficulties faced by generation generally, and generation and demand side in the distribution system in receiving credit for avoiding investment in transmission. There are also changes to transmission arrangements outlined in Chapter 6 which may assist in providing appropriate locational signals for generation. The Congestion Management Review before the AEMC is focusing on this issue.

Inter-regional trade

As detailed above, inter-regional trade across the NEM is an important feature of the market. It supports competition; provides inter-regional shared security; load diversification; power transfers from low cost to high cost regions; and, where signals emerge, investment incentives for generation across the regions.

The regional structure of the NEM allows prices to be different in different regions. When inter-regional links are un-constrained, prices should differ by loss factors only. When inter-regional links are constrained, prices separate with electricity flowing generally from the low priced to the high priced region. Generators in the low priced region receive the price in their region, and the exports to the high priced region are accrued by NEMMCO as a form of inter-connector rent, called settlement residues.
Settlement residue auctions

Under the current NEM rules, settlement residue cash-flows are auctioned by unit in quarterly tranches 1 year in advance. This is known as the settlement residue auction (SRA). NEMMCO is responsible for administering the SRA process.

The cash-flow proceeds from the SRAs (the auction premium) are deducted from the Transmission Use of System (TUOS) charges which customers pay in each region, so customers receive the benefits of the auction proceeds in addition to the benefits of competition from inter-regional trading. The rights to the cash-flows for the settlement residue (spot) go to the successful bidder at each quarterly SRA. The successful bidder receives the cash-flow proceeds of the settlement residues.

The rights to the settlement residue cash-flows are the property of TUOS customers until they are auctioned. From this perspective, the cash-flows from the settlement residues are an asset of the customers who are levied TUOS charges.

It was envisaged that the cash-flows from spot settlement residues would provide a hedge for trading across inter-regional links and therefore enhance inter-regional trade. This has occurred.

Table 9 shows the results of settlement residue auctions and the premium collected versus the settlement residues over time.

### Table 9: Inter-regional hedging: Premium collected versus spot

<table>
<thead>
<tr>
<th>Year</th>
<th>Premium (Auction proceeds) $m</th>
<th>Spot (Settlement residue) $m</th>
<th>Excess of spot over premium $m</th>
<th>Excess of spot over premium %</th>
</tr>
</thead>
<tbody>
<tr>
<td>1999/2000</td>
<td>41</td>
<td>60</td>
<td>19</td>
<td>46</td>
</tr>
<tr>
<td>2000/2001</td>
<td>64</td>
<td>105</td>
<td>41</td>
<td>64</td>
</tr>
<tr>
<td>2001/2002</td>
<td>87</td>
<td>98</td>
<td>11</td>
<td>13</td>
</tr>
<tr>
<td>2002/2003</td>
<td>62</td>
<td>120</td>
<td>58</td>
<td>94</td>
</tr>
<tr>
<td>2003/2004</td>
<td>81</td>
<td>141</td>
<td>60</td>
<td>74</td>
</tr>
<tr>
<td>2004/2005</td>
<td>105</td>
<td>230</td>
<td>125</td>
<td>119</td>
</tr>
<tr>
<td>2005/2006</td>
<td>118</td>
<td>220</td>
<td>102</td>
<td>86</td>
</tr>
<tr>
<td>Total</td>
<td>558</td>
<td>974</td>
<td>417</td>
<td>75</td>
</tr>
</tbody>
</table>

This shows that the settlement residues have exceeded the premium collected by around 75% on average since 1999/00. Some $417 million has been paid out more than has been received. Essentially this sum represents a risk premium.

Table 10 analyses this by inter-connector. The links surrounding Snowy have been grouped.

### Table 10: SRA premium and settlement residues (Annual average for all interconnectors, financial years 2000/01-2005/06)

<table>
<thead>
<tr>
<th>Link</th>
<th>Premium (Auction Proceeds) $M</th>
<th>Spot (Settlement Residue) $M</th>
<th>Excess of Spot over Premium $M</th>
<th>Excess of Spot over Premium %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Snowy Region Links</td>
<td>58.7</td>
<td>97.2</td>
<td>38.5</td>
<td>66</td>
</tr>
<tr>
<td>Vic-SA</td>
<td>14.9</td>
<td>18.3</td>
<td>3.4</td>
<td>23</td>
</tr>
<tr>
<td>QLD-NSW</td>
<td>15.0</td>
<td>38.0</td>
<td>23.0</td>
<td>153</td>
</tr>
</tbody>
</table>
This shows that:

- the Snowy region comprises 63 per cent of the settlement residues and 60 per cent of the risk premium. The risk premium for the Snowy region averaged $38.5 million per year since 2001–02 or a return of 66 per cent;
- the link between Queensland and New South Wales had the second highest (dollar) risk premium. The risk premium averaged $23 million per year since 2001–02 or a return of 153 per cent; and
- the link between Victoria and South Australia had the lowest (dollar) risk premium. The risk premium averaged $3.4 million per year since 2001–02 or a return of 23 per cent.

Sources of Volume Risk

Total SRA risk premiums since 2000/01 across all inter-connectors, and the potential sources of the volume risk associated with these risk premiums, is analysed in detail in Appendix 9. From this analysis it can be shown that:

- since 2000–01 when Queensland was connected to New South Wales, a total of $128 million has been accrued and the risk premium on the QLD-NSW inter-connector can be mainly explained by transmission constraints in northern New South Wales;
- since market start the significant $251 million risk premium on the Snowy-NSW inter-connector is less related to transmission factors and more explained by the incentives the Snowy regional design creates for Snowy bidding behaviour. The $47 million SRA risk premium on the VIC-Snowy inter-connector is related to these incentives; and
- the $30 million risk premium on the VIC-SA inter-connector can be largely explained by transmission factors across the inter-connector and intra-regional congestion.

These SRA risk premiums are borne by customers of the NEM. In addition, competition in interstate trade is less than it would be if these risk premiums were lower.

A more detailed analysis of the sources of these risk premiums between regions is found in Appendix 9. However a brief overview is provided here.

South Australia

The link between South Australia and Victoria is addressed first as it is the simplest. The link flows from Victoria to South Australia are shown in Figure 25 when there is price separation between VIC-SA greater than $100/MWh. The link flows occur on Murraylink and the transmission line through Heywood.
The VIC-SA inter-connector has superior consistency of performance compared with the other links. However, its performance is still short of its rated capacity of 620 MW. There are some occurrences where flows are significantly below the normal capacity of the link when significant price separation occurs.

The primary sources of volume risk are:

» significant de-rating of the Heywood line; e.g. to half its normal capacity when lightning occurs;

» line outages (in this period, particularly Murraylink); and

» contingencies surrounding the operation of the Northern Power Station which transfer volume risk onto the VIC-SA inter-connector.

Queensland
The volume of electricity flowing across the QLD-NSW inter-connectors (QNI and DirectLink) when there is price separation between QLD-NSW greater than $100/MWh is shown in figure 26.
This shows that flows from Queensland to New South Wales are limited significantly below the rated capacity of 1300 MW at times when there is significant separation between the regions.

As detailed in Appendix 9, the primary source of loss of capacity on this link is the existence of transmission constraints in NSW. The behaviour of Millmerran generator also plays a part.

Snowy

Similarly, the volume of electricity flowing across the Snowy-VIC inter-connector when there is price separation between Snowy-VIC greater than $100/MWh is shown in figure 27.
This shows similar outcomes for flows against the rated capacity of the inter-connector of around 1600 MW when there is significant price separation between the regions.

The volume of electricity flowing across the Snowy–NSW inter-connector when there is price separation between Snowy-NSW greater than $100/MWh is shown in figure 28.

28 Snowy-NSW flow when price separation greater than $100/MWh

This shows that the link from Snowy to NSW is generally firm.

Similarly, the volume of electricity flowing across the VIC-Snowy inter-connector when there is price separation between Snowy-VIC greater than $100/MWh is shown in figure 29.

29 Vic-Snowy flow when price separation greater than $100/MWh
This shows that flows were well below the link capacity of around 1600 MW.

The dominant factor determining flows in the Snowy region is the bidding behaviour of Snowy Hydro. This is detailed in Appendix 9 where it is shown that a significant intra-regional constraint in the Snowy Region, in concert with Snowy Hydro's bidding behaviour around this constraint, is the source of significant volume risk across Snowy-NSW and VIC-Snowy. This volume risk is related to the SRA risk premiums across both inter-connectors.

The purpose of these illustrations and commentary is to show the material volume risk associated with inter-regional capacity and its key causes. It can be seen that link performance from QLD to NSW and Snowy to VIC is poor, causing volatility in settlement residues. However, the main reasons are different. The performance of the links surrounding Snowy are dominated by the bidding behaviour of Snowy. For Queensland, there are constraints in northern NSW. For SA, the primary factor is de-rating of inter-connectors such as when lightning occurs.

**Stakeholder views on inter-regional trading**

According to Ergon and Verve, network congestion is a key concern for generators as it increases the risk of trading. Submissions also note that inter-regional transmission capacity and generator bidding behaviour increase volatility in spot prices and decrease liquidity.

Gallaagher and Snowy Hydro see the lack of accountability from TNSPs and NEMMCO for the performance of the network as a serious impediment to efficient trading in the NEM. A more commercially focused and market-oriented transmission access regime that provides real market signals for the value of transmission services is required. See also the discussion in Chapter 6.

**Managing trading risk across the NEM**

The value of settlement residues depends on price differences between regions, and the volume of electricity that flows across inter-regional links when there are price differences. Financial markets are very effective at managing price risk but less effective in managing volume risk. There are also significant competition and market design issues when participants in the settlement residue auction are bidding against parties who can influence or control the underlying settlement residues.

Participants are discounting the value of settlement residues. The risks underlying the discounting arise primarily from volume risk, specifically:

- transmission outages;
- transmission assets do not have a firm capacity, but instead operate at different capacity levels depending on the electrical conditions and other constraints;
- generators can exert a material influence on the dynamic capacity of a link by their offers to the market. As discussed in the above example, this is particularly relevant in the case of Snowy Hydro which can influence inter-connector flows between NSW and Victoria by bidding strategically at times of high prices in NSW. This effect is somewhat contrary to the intent of the market that transmission be a common carrier; and
there can also be ‘negative settlement residues’ when electricity flows from high to low priced regions. Although this effect is small, it is another risk factor which has been addressed to some extent by the AEMC.

This suggests:

- there should be scope to better manage the risks in these inter-regional instruments. If so, this should result in much of this risk premium being captured for customer benefit;
- benefits will accrue if transmission solutions can be justified which firm up the flows, however the results are uncertain and the time frame likely to be extended. Transmission upgrading should take account of the high value that the market places on firmness;
- the Snowy region design could be reconfigured to better manage this risk and improve dispatch efficiency;
- generators could be contracted and rewarded for supporting inter-connector flows (and then be penalised for adversely affecting inter-connector flows). The mechanism to implement this measure is available (through NEMMCO and TNSPs) but there may be insufficient incentives for this to occur without further changes and improved clarity in responsibility as between NEMMCO and TNSPs;
- the SRA process could be redesigned to capture more of the risk premium for customers and better support inter-regional hedging as detailed below; however
- negative settlement residues which result from least cost dispatch across the network should remain.

Snowy

The most easily identifiable example of the contribution that intra-regional congestion and generator bidding behaviour has on influencing inter-connector flows occurs in the Snowy Region. There is a material constraint in the middle of the Snowy Region which has a limit of about 1350 MW. Snowy has, at times, the potential to strategically operate generation on each side of this constraint. At the same time, Snowy must trade both intra-regionally and inter-regionally given there is no material demand within the Snowy Region itself and it must participate in the SRA auctions to manage its business even though it has the major influence on settlement residues and the flows at crucial times.

Snowy’s bidding behaviour in combination with the impact of intra-regional congestion potentially contributes to the volume risk across inter-regional links identified in the preceding analysis.

In addition, the Snowy region is unusual in the NEM. It is the only region which does not contain a material load. The most material constraint lies in the middle of the region at about 1350 MW. Snowy Hydro can only trade by taking inter-regional risk and yet Snowy bidding behaviour can affect inter-connector flows, potentially creating inefficient outcomes. Snowy can, and does, influence the value of the settlement residues and participates in the settlement residue auctions – indeed it must in order to operate its business. The workings of the Snowy Region seem to act to impede trade and competition between the two most interconnected states of NSW and Victoria and also impact on the efficiency of dispatch of Snowy generation.
There have already been changes in this area with Snowy being contracted under a constraint support contract and two rule changes are currently before the AEMC.

Potential solutions to the Snowy Region issue have been suggested and these include removing the region altogether. However, removing the regional boundary alone is unlikely to be sufficient to deliver efficient outcomes and support trade between NSW and VIC. Snowy would still be able to control flows on the link. A more comprehensive package of solutions may be required probably including contracting Snowy to support flows when prices separate between VIC and NSW, but perhaps be limited in its participation in the SRA auctions. This is not an unreasonable expectation given that it is understood that Snowy Hydro would benefit materially from the removal of the Snowy region and a regional boundary change would be limited in its benefits without such an arrangement.

(Note that NEMMCO already contracts a Network Control Ancillary Service from Snowy to support inter-connectors flows, but the suggested arrangement outlined above would be in addition. It is noted that NEMMCO has a Rule obligation to review the acquisition of NCAS including those which could support inter-connector flows to the benefit of the market. NEMMCO has advised that it has deferred this review until the AEMC review into congestion is complete in order not to cut across the outcomes of that review).

It appears that the AEMC is limited in its ability to develop a solution which goes beyond a rule change. This raises questions as to whether AEMC has sufficient powers in this regard or whether its powers in concert with those of NEMMCO might be sufficient. Governance issues surrounding the AEMC are discussed at length in Chapter 5.

**Generator bidding behaviour**

Where generators control or materially influence flows on inter-connectors, there is a case for contracting generators to support flows on the network if the benefits outweigh the costs.

**SRA design**

Settlement residues are the property of the customers in the NEM. However they are being discounted heavily for the volume risks within them such that customers are not receiving the full benefit of the settlement residues. This is not to suggest that customers receive no benefit. Customers receive the premium collected and benefit from the competition between regions which the SRA auction supports.

There seems to be a substantial opportunity to extract more value from the settlement residues, to the benefit of customers and at the same time making the market more efficient. The objective would be to capture more of the current risk premium for customers while simultaneously increasing competition between regions by providing a firmer instrument thereby encouraging more parties to participate.

As discussed above, the settlement residues are considered to be an asset owned and managed on behalf of TUOS customers with spot earnings of around $200 million per year. At a multiple of 15 times, this asset has an indicative present value of $3 billion. Settlement residues constitute a business, and need to be managed in a more business-like way which delivers more value to customers and better supports the inter-regional trading market. This would be beneficial even if there were improvements in transmission performance and generator support for inter-connectors.
In 2003 and 2004 NEMMCO did substantial work on this topic. It engaged MMA to prepare a proposal for providing ‘firm transmission rights’ to the market using inter-regional settlement surpluses. Essentially this proposal is similar to the concept proposed here. However the ERIG proposal was developed separately because ERIG was unaware of the MMA work until the ERIG process was almost complete. Parer also recommended the implementation of similar but different firm transmission rights to facilitate inter-regional trade.

Stakeholder views on SRA design

NEMMCO and Snowy Hydro note that settlement residues are not perfectly correlated with the risk of trading inter-regionally. Some participants have said that this makes the SRA a speculative instrument in participants’ trade books rather than a hedging instrument.

AGL supports an examination of the SRA process to see if it can be improved. The ERAA also supports improvements to the SRA process to improve firmness but this must not be done by artificial means as this would lead to inefficiencies. Rather the problem should be addressed at its source which is the reliability of inter-connector transfer capability with greater incentives on TNSPs to maintain transfer capacity. Powerlink concurs with this.

Energy Australia, EIIA, ERAA, MEU and Ergon believe that the lack of a reliable inter-regional hedging instrument creates risks for participants trading across regional boundaries.

Energy Australia, Origin Energy and the ERAA propose that SRAs should have a longer contract term as this has significant risk management benefits. However, Westpac contends they should also be sold on very short term notice to promote a short term market rather than all in quarters.

Snowy and the NGF argue that ERIG’s analysis of volume risk across inter-connectors does not fully recognise the root cause of this risk and that any redesign of the instrument would be inefficient if this root cause is not recognised. Furthermore, it has been noted that ERIG’s analysis of customer benefits does not include the benefits to customers of inter-regional trade and enhanced competition that SRAs provide.

Eraring does not support changes to SRA design. NEMMCO, in comments on ERIG’s discussion paper, argued that ERIG’s analysis was lacking and that a full analysis of the market implications of any emerging proposals should be carried out, with stakeholder input, prior to reaching any conclusion to consolidate them. Ultimately there needs to be a net benefit from any change.

Macquarie Generation points to the option whereby NEMMCO uses auction proceeds to support SRA payments when there are insufficient funds to pay the full SRA value, and agrees that this option could deliver a range of benefits.

Origin is not convinced that the proposed SRA redesign proposals would assist in managing inter-regional risk. Origin agrees that the use of collected auction premiums to support spot payments would be beneficial to participants, but presumably this would reduce the residual funds for TUOS reductions. Further analysis is required.

TRUenergy is of the view that firming up settlement residue instruments by artificial techniques has the risk of distorting the contract and, as a result, the investment market...
for generation. This can occur as the contract market for inter-regional trading becomes more ‘firm’ than the underlying physical flow. This means that a customer can with impunity contract across an asset that is not performing—the result being a shortfall of physical supply. The ESAA argues that the measures proposed to firm-up SRAs are still sub-optimal and there is a real risk they will only serve to further distort the market.

Finally, in relation to Snowy, Country Energy argues that any proposed changes to the regional boundary should only proceed if it can be proven that it will enhance certainty in the market and improve efficient financial trading arrangements for market participants.

Analysis of SRA design

There seems to be a case for the SRA product to be redesigned with a view to more fully capturing its underlying value by better managing the risks within SRAs. This could, if successful:

- result in customers receiving the full value (or very close to the full value) of the settlement residues, and
- provide an instrument which better supports inter-regional trade (thereby supporting competition).

A redesign of the SRAs might be expected to involve some or all of the following features:

- setting a nominal capacity for each link, e.g. the average (or weighted average) capacity at the times when prices separate materially;
- possibly only triggering the SRA when the price difference exceeds a threshold. This could separate price differences arising from losses from those arising from congestion;
- use of the collected auction premium to support spot settlement residue payments if required;
- auction premiums across the inter-regional links could be pooled to support spot payments if required to diversify risks across links; and
- longer dating of SRAs to diversify volume risk over a longer period.

The reconfiguration of SRAs needs to be driven commercially as a business (though with a public policy objective) and it is clear that this is not an appropriate role for NEMMCO in its current form.

As shown in Table 9 the risk premium associated with the SRA product was over $100 million in each of the last 2 financial years, and the trend is for this to increase. By re-designing the SRA instrument, ERIG considers that it is possible to capture most, if not all, of this risk premium for customers, while at the same time increasing interstate competition.
ERIG findings and recommendations

Inter and Intra Regional Trade
There is a need for refinement of intra-regional location signals.
However, full nodal pricing should not be pursued as a solution.

- Embedded generation (and firm demand side) should receive the benefit of avoiding the need for or supporting the operation of transmission assets.
- Generators which support the operation of transmission or obviate the need for upgrading and are reliable be paid for these services.
- Consider some form of transmission pricing to signal the locations where generation is able to best support transmission.
- The mechanisms supporting inter-regional trade are not working efficiently and adding to risk premiums in the market.
- The rationalisation of the Snowy Region is indicated.
- There is room to improve the design of the SRA product, particularly, the SRA auction process to create firmer transmission rights. The benefits of this measure, based on recent history, would be around $100 million per year for NEM customers.

ERIG recommends that:

- AEMC clarify the roles of Network Service Providers and NEMMCO in contracting generation to support transmission capacity and flows.
- AER with the AEMC, develop the framework for encouraging NSPs to enter into network support contracts where generators or demand side contribute to avoiding or deferring transmission investment. These should be simple and standardised arrangements for DSM or generation embedded in the distribution system.
- NEMMCO develop market support contracts where generators or demand side are able to support flows on transmission assets which improve energy market outcomes and where the costs exceed the benefits.
- The inefficiencies created by the operation of the Snowy Region be resolved as a matter of urgency. AEMC should be provided with a broad brief by MCE to resolve this matter by December 2007, including an interim solution if the Snowy Region is abolished, to cover the 3 years notice before a regional change can be implemented.
- To ensure the settlement residue instrument delivers the most efficient outcome, the MCE commission an independent feasibility study designed to improve the management of settlement residues as detailed herein.
Settlement of the spot and contract markets and credit

Under the NEM Rules, NEMMCO has responsibility for spot market settlement arrangements. NEMMCO manages the spot market prudential position of all NEM participants to guard against the market ramifications of default.

NEM participants must provide NEMMCO with credit support in the form of bank guarantees to ensure participants meet their financial obligations on purchases from the NEM pool. The Maximum Credit Limit (MCL) arrangements are a key component of the prudential arrangements in the NEM. Essentially, the MCL is a mechanism to assist in managing NEMMCO’s settlement risk in the NEM.

Under section 3.3 of the Rules, NEMMCO must determine an MCL for each market participant and review that MCL at least once every year. The amount of credit support required is based on each market participants’ prescribed MCL. This limit is determined through a prescribed methodology employed by NEMMCO. NEMMCO can call upon the guarantees in the event of a NEM participant defaulting on their physical settlement obligations.

NEM participants manage the financial risks associated with spot price volatility through secondary market financial instruments. These instruments also involve credit risk and prudential arrangements that are separate from those used by NEMMCO in the spot market. The interaction between spot and forward settlement is depicted in Figure 30 below.

30 Relationship between spot and forward market settlement

It has been argued that the duplication of prudential requirements across settlements in the spot and forward markets create inefficiencies which impact on new entrants and investment through higher than necessary operational costs, risks and capital requirements. These concerns were also raised by Parer (2002).
To better understand these issues, the ERIG Financial Markets Discussion Paper specifically asked industry how perceived settlement and credit inefficiencies in the NEM could be better addressed. Two potential options to improve the integration of spot and financial settlements for electricity were proposed:

Continuation of the current separation of settlement responsibilities and addressing the subsequent inefficiencies associated with this approach as they arose, including through:

- shortening the credit cycle with a view to reducing spot market prudential requirements progressively over time;
- developing a practical way in which SFE contracts can offset MCL credit requirements; and
- supporting an industry-led voluntary clearing house in which OTC contracts would be netted against spot market settlements.

The implementation of a national settlements and clearing (NSC) facility.

Stakeholder views on settlement of the spot and contract markets and credit

Many discussion paper submissions received were opposed to changes to the existing settlement and credit arrangements in the NEM. Those submissions that were not opposed to change, proposed that further analysis would be required before any changes were made to existing arrangements and that participation in any mechanism put in place by policy makers to improve credit should be voluntary.

Others argued that the importance attached to credit inefficiencies by ERIG and others has far exceeded its actual impact on the efficiency of the market and that no compelling case had been made to change from the existing arrangements. Further, some submissions suggested that the main consideration of policy makers with respect to credit in the NEM should be to ensure that the credit quality of the mandatory spot market does not experience any reduction in quality.

Submissions also noted that the current reallocation proposals before the AEMC were examples of the market working to resolve inefficiencies and that these initiatives should be given a chance to be considered by the AEMC and tested in the market.

There was little specific comment related to the first option set out in the discussion paper, viz maintain current separation of spot and financial settlements and address inefficiencies as they arise.

The second option proposed in the discussion paper, implementation of a NSC facility, was supported by NEMMCO and the ASX in their discussion paper responses. Both parties contended that the establishment of a NSC could provide material benefits to the NEM, particularly in view of the inherent volatility of NEM spot prices. The ASX submission notes that:

“Implementation of a national settlements and clearing facility would be the most effective option to resolve credit duplication and more importantly, reduce the systemic risk of default in the NEM.”
Availability of credit support for market participants

Credit capital to mitigate credit default risk in the NEM is held in the form of financial guarantees. There is no indication at this stage that credit financiers are unable or unwilling to provide financial guarantees to market participants.

Table 11 summarises the extent and source of credit support provided to NEMMCO by market participants.

**11 Credit Support Provided to NEMMCO – September 2006**

<table>
<thead>
<tr>
<th>Form of credit support</th>
<th>$m</th>
<th>%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bank guarantees</td>
<td>572</td>
<td>36</td>
</tr>
<tr>
<td>State Treasury Corporations</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Queensland</td>
<td>347</td>
<td>22</td>
</tr>
<tr>
<td>Other</td>
<td>660</td>
<td>42</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$1,579</td>
<td></td>
</tr>
<tr>
<td>Estimated annual cost using a range of 25-100bp</td>
<td>4-16</td>
<td></td>
</tr>
<tr>
<td>Aggregate reported segment results for retailing businesses for major retailers</td>
<td>1,800</td>
<td></td>
</tr>
<tr>
<td>Estimated costs as a share of operating profits</td>
<td>less than 0.5%</td>
<td></td>
</tr>
</tbody>
</table>

Source: KPMG

Meeting credit support requirements

At initial analysis, the overall financial cost of meeting credit requirements is small in the scheme of the profitability of the industry (estimated at less than 0.5% of the aggregate reported segment results for major NEM retailers). However, some stakeholders have observed that access to financial guarantee facilities and the higher cost due to lower credit standing will remain an issue for capital constrained new entrants (where the equity cost can be in the range of 15-20%). This disparity is a natural consequence of the credit market pricing for risk.

In addition the credit support provided to NEMMCO (as detailed in table 11) does not accurately reflect the extent of credit support required by NEM participants. This is because participants are required to top up their credit to NEMMCO to stay under their Trading Limit to avoid receiving a Call Notice. As such, participants need to have credit support accessible in addition to their existing arrangements should the market cap price of $10,000/MWh be reached for an extended period and a call notice received. Theoretically, the maximum possible increase in exposure in a day would be about VoLL x NEM max energy in 7.5 hours = $10,000 x 7.5 x 32,000MW = $2.4 billion. This is limited to about 7.5 hours of VoLL due to the operation of the Cumulative Price Threshold (CPT). As the CPT is a seven day assessment, over four weeks this could conceivably rise to nearly $10 billion until a party were able to collect on its contract payments to offset the NEMMCO call. While NEMMCO has not issued a call notice since December 2001, parties need to be prepared to manage a call notice, or a requirement to maintain trading amounts under trading limits...
within a very short time frame. This demonstrates the reduction of systemic risk which could be achieved by addressing this issue.

To explain this, each morning at 8.00am, NEMMCO assesses parties trading amounts against their trading limits. Parties have until 10.00am to rectify their position - in most cases by making an immediate security deposit or increased credit support. The largest daily shortfall that has been required was approximately $240 million. As such, noting this short time frame and the potentially large increase in exposure in a day, readily accessible credit support arrangements need to be in place to minimise risk.

**Pricing of credit support**

The financial strength of energy retailers in the NEM varies from highly rated state government owned corporations to unrated new entrants in energy retailing. Relative creditworthiness is typically measured in terms of long-term senior-unsecured issuer ratings as assigned by Moody’s or Standard & Poor’s. Agency ratings are a qualitative and ordinal measure of creditworthiness, which is defined in quite general terms.

Table 12 compares the indicative long term ratings of market participants with the estimated cost of financial guarantees using industry standard credit pricing methodology.²

### 12 Cost of Credit Support by Long Term Issuer Credit Rating

<table>
<thead>
<tr>
<th>Market participation</th>
<th>Long Term Credit Rating</th>
<th>Sub-investment Grade (BB-B)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Government owned corporations</td>
<td>AAA</td>
<td>25</td>
</tr>
<tr>
<td>Major integrated energy groups</td>
<td>AA</td>
<td>25</td>
</tr>
<tr>
<td>Other participants and new entrant retailers</td>
<td>A</td>
<td>50</td>
</tr>
<tr>
<td></td>
<td>BBB</td>
<td>100</td>
</tr>
<tr>
<td></td>
<td></td>
<td>400–1700</td>
</tr>
</tbody>
</table>

Source: NEMMCO submission, KPMG analysis

The analysis highlights the broad distribution of creditworthiness of market participants across the NEM. KPMG also notes that the cost of credit support increases significantly below investment grade - most of the vertically integrated energy businesses have investment grade (BBB or higher).

² The credit pricing methodology takes account of cumulative default probabilities (DF) and loss given default (LGD) analysis.
Increasing efficiency in credit support requirements

Settlement re-allocations

NEM participants are able to offset their spot market obligations against future cash flows via NEMMCO. Referred to as settlement re-allocations, this mechanism is designed to reduce the amount and cost of credit support required by market participants. The existing settlement reallocation mechanism has not been used extensively to date. Historically, re-allocations account for less than 2 per cent of wholesale market settlements and do not appear to represent an efficient mechanism to manage credit risk except in the case of vertically integrated energy groups and smaller retailers.

A study of the settlement re-allocation process commissioned by NEMMCO in 2005 attributed the low utilisation to:

- confidentiality concerns over centralisation of financial information (with NEMMCO);
- lack of a financial incentive for generators to participate, as they would suffer a loss of credit standing of their receivables;
- ready or implied access to state treasury arrangements for some government owned retailers;
- lack of comprehension of the significant consequences of a participant default with its possible cascading effect; and
- the operation of government equalisation funds (e.g. ETEF).

Shortening the settlement cycle

It has been brought to the attention of ERIG that market operators and clearing houses in other markets, including Nordpool, have reduced prudential risks by reducing the length of their settlement cycles and introducing central counterparty clearing services. KPMG analysis advises that a mandated reduction in the NEM settlement cycle over time is a desirable policy response to addressing further concentration of credit risk in the NEM. ERIG supports this conclusion but notes it only partially addresses prudential requirement by NEMMCO.

Rule change proposals before the AEMC

Table 13 summarise details of proposals submitted to the AEMC on the proposed rule changes to the settlement re-allocation process. It is understood that both the ASX/SFE and NEMMCO proposals would lead to the establishment of a voluntary clearing house.

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3 NEMMCO Prudential Processes in the National Electricity Market, Deloitte, July 2005
### 13 Summary of Proposals to AEMC on Amendment to Settlement Re-Allocation Process

<table>
<thead>
<tr>
<th>Features</th>
<th>Current</th>
<th>NEMMCO Proposal</th>
<th>ASX/SFE Proposal</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Benefits for NEM participants</strong></td>
<td>• Participants can offset cash flows associated with spot market obligations*</td>
<td>• Participants are able to offset cash flows associated with derivatives &amp; spot market obligations</td>
<td>• Futures contracts can be offset against a participant’s financial contracts &amp; spot market obligations</td>
</tr>
<tr>
<td></td>
<td>• Ex ante reallocations reduces credit support requirements</td>
<td>• Ability to offset derivative positions against spot market transactions</td>
<td>• Exposure is limited to only one business day</td>
</tr>
<tr>
<td></td>
<td>• Takes into account all pricing periods over the life of the contract</td>
<td>• Participants can further reduce credit requirements</td>
<td>• Futures contract is guaranteed by the exchange i.e. is much firmer compared to reallocations</td>
</tr>
<tr>
<td></td>
<td>• Reduces liquidity risk for participants during peak periods i.e. avoid cash settlement</td>
<td></td>
<td>• Easy to enter and exit futures contracts</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>• Has no credit risk weighting under Basel 2</td>
</tr>
<tr>
<td><strong>Risks of participation &amp; issues to be addressed</strong></td>
<td>• Non firmness of reallocations, NEMMCO can terminate reallocation if one party defaults</td>
<td>• NEMMCO is solely responsible for determining what is an acceptable reallocation</td>
<td>• Requirement for margins which can require top up on a daily basis</td>
</tr>
<tr>
<td></td>
<td>• Concentration risk, scheme limited to generators &amp; retailers</td>
<td>• Credit support may be unable to cover default events during peak pricing periods</td>
<td>• Futures prices does not include spot prices that occurs between 5:10pm and the next business day</td>
</tr>
<tr>
<td></td>
<td>• Difficulty in closing out reallocation contracts, has to be with participant in same region</td>
<td>• Doesn’t cover compensation aspects for losses suffered if a party to a reallocation defaults</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Derivative position of parties to a reallocation are not recognised</td>
<td>• Reallocations attracts credit risk weightings under Basel 2</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Ex-ante reallocations are outside NEMMCO’s prudential process</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Source: KPMG
While the rule change proposals detailed above are appropriately for consideration by the AEMC, from a strategic perspective, ERIG would endorse arrangements that maximise settlement flexibility while still providing credit assurance to NEM participants. In principle, ERIG supports both proposals, subject to detailed analysis by AEMC. ERIG also notes the view of KPMG that the ASX/SFE proposal is a positive initiative providing participants with an efficient mechanism to reduce the cost and systemic risk of credit support.

**Integrating spot and forward markets in the NEM**

Combining like processes increases economies of scale and improves efficiency through specialisation. It is recognised that while some market incumbents are opposed to changes to the existing settlement and credit arrangements in the NEM, there are arguments for combining these separate processes for spot and contract settlements in the NEM.

ERIG considers that the establishment of a settlements and clearing exchange for spot and financial contracts which are settled simultaneously with the lag time eventually minimised, would facilitate the removal of duplicated prudential requirements by enabling an overall exposure to be assessed and managed. Further, it would reduce credit entry barriers for new entrants, lower credit requirements through shorter settlement cycles, mitigate potential concentration risk concerns of credit suppliers and minimise credit risks under the untested retailer of last resort provisions. Perhaps most significantly, systemic risk would be materially reduced. Finally, it would reduce or remove the free rider credit enhancement provided to generators by the pool.

Significant central counterparty settlement and clearing facilities are already commercially provided to the ASX, SFE and other markets around the world. Accordingly, clearing and settlement services could be leveraged off an existing service provider e.g. the ASX/SFE. ERIG notes the position of the ASX that if it were provided greater clarity from the MCE, it would progress a design study to achieve the integration of its existing CCP clearing and settlement infrastructure for the NEM spot market. Alternatively, NEMMCO’s functions could be expanded to take on the national settlements and clearing role provided NEMMCO could satisfy participants in relation to governance and confidentiality. Either clearing house would be established for use on a voluntary basis and in any event more complex contracts would need to be settled bilaterally.

Rigorously examining the feasibility of establishing a settlement and clearing facility and a strategy for its implementation is not achievable in the time ERIG has available to it. Further, determining who should run such a service should there be a net benefit is not a decision for ERIG. As such ERIG proposes that the MCE commission an expert group with industry representation to develop a plan for, and evaluation of, the integration of spot and forward markets in the NEM.

This additional analysis by an expert group may assist in overcoming the reluctance of incumbents to change. This is because modifications to existing arrangements would not occur absent the identification of net benefits from the integration of spot and forward markets in the NEM. Further, the time required to complete the review will allow existing proposals for improvement to the AEMC to be considered and potentially tested in the market.
ERIG findings and recommendations

Settlement of Spot and Contract Markets and Credit

Under the current NEM design, spot and contract markets are largely settled separately. This results in duplication of credit requirements in the spot and contract markets. This situation increases systemic risk, creates timing differences and increases barriers to entry and is increasingly important with the privatisation of retail in Queensland.

While ERIG would expect that a restructured NEMMCO would deal with all operations related to the market, it is recommended in the interim that:

» The MCE commission an expert group with industry representation to develop a plan for the integration of spot and forward markets in the NEM. This investigation should explicitly examine the feasibility of establishing a voluntary national settlements and clearing facility and a strategy for implementation should the benefits outweigh the costs. This group should report back to the MCE by December 2007 with options and solutions.

» AEMC and NEMMCO, in the interim period, develop a plan for integrating SFE contracts into the NEMMCO settlement process, to be implemented by September 2007, subject to the risks being managed appropriately.

Short term forward market

The MCE requested that ERIG consider the benefit of introducing a Short Term Forward Market (STFM) in the NEM. As such, the ERIG Financial Markets Discussion Paper specifically asked industry whether the trial of a STFM would add value and if it would, evidence of the benefits it would deliver.

Stakeholder views on a STFM

Stakeholders do not support stimulation of a STFM. In the event that ERIG nevertheless decided to support a trial, stakeholders emphasised that NEMMCO should not be involved because it should focus only on its market operations role and there were concerns about the governance of NEMMCO.

The key reason a STFM was not supported was the stakeholder view that there was no market demand for it. If there were demand, it was argued the market would deliver it. Further, submissions noted there was no evidence to suggest a STFM would deliver demand side benefits or reduce credit duplication or prudential risk. The final argument opposing a STFM was that short term trading is available to the market through the OTC and arguably, the futures exchange, in any case.

Findings on a STFM

A STFM would be intended to provide a service to the industry. Without industry participation, it would serve no purpose. In the absence of industry support for a STFM trial, ERIG sees no role for Government in facilitating the development of a short term forward market. No commercial party, has so far been prepared to put resources behind developing a STFM to test its value to the market. In the normal course of events, this is the process which should be followed.
Demand response

In competitive and efficient markets, prices are formed through the interaction between buyers and sellers - the demand and supply sides of the market. Ideally this should occur in the short, medium and long term.

In terms of the medium and longer term response, an efficient competitive market should result in cost reflective prices. This should result in customers with a more peaking profile paying for that service, e.g. customers with substantial air conditioning load, all else being equal, should pay more for this service, reflecting the costs incurred on the networks and generation system to supply this demand.

Cost reflective pricing provides the medium and longer term signal for customers in relation to their capital and usage decisions. Retail price controls impede this activity and result in cross subsidies, where customers which have expensive profiles to supply do not receive accurate pricing signals about the cost of using electricity, particularly at peak times. Recommendations related to retail price controls can be found in Chapter 5.

This section is largely focused on short term demand response. In the short term, the demand side can play a role in the spot market, where customers prefer or are able to organise their demand so as not to consume at times of high spot prices.

In the short term, the response of demand in the NEM has been relatively inactive. This has implications for the efficient operation of the electricity market. At times of high demand and relatively scarce supply, relatively small reductions in demand have the potential to move the supply and demand interaction down the price curve significantly. This could result in significant benefits across the market, primarily as a result of reduced need for peaking investment, and could also contribute to the security of supply.

The benefits from having an effective demand side response in the market include:

» increased reliability;

» a move away from regulated reliability standards as the market will clearly identify and respond to the value of reliability;

» reduced ability of generators to exercise market power as extremely high prices are less likely; and

» reduced total energy costs because of the lower level of installed generation capacity required and deferral of network augmentation. If 3000 MW of demand could be harnessed, benefits well in excess of $100M in the medium to long term (in nominal terms) could be achieved in the generation sector with benefits also accruing in the networks. This is equivalent to approximately $25 million per year in present value terms and is discussed further in Chapter 8.

The MCE is currently developing a demand side response program comprising a range of initiatives including a plan for the roll out of electricity smart meters in 2007 on the basis of positive cost-benefit assessments.

ERIG also notes the decision by Victoria for interval meters to be rolled out for all customers from 2008, whilst interval meters for small users in NSW and QLD are voluntary; and interval meters will be installed on a new and replacement basis in the ACT.
Stakeholder views on Demand Side Management

A number of stakeholders referred to the current untapped potential of demand side opportunities. While recognising this, a number of submissions also noted that DSM is maturing and will continue to develop over time.

Submissions consistently noted that the biggest obstacle to further demand side contracting is the administrative burden of customers managing contracts. Further, a clear majority of participants noted across submissions and consultations the important role aggregators, customer education and the delivery of price signals through advanced interval meters will play for successful DSM. Stakeholders were also unanimous in recognising that the existence of retail price caps limits the effectiveness of DSM.

Submissions contend that demand side responses could be better harnessed provided that consumers can lock in the benefit of demand side responses in advance and plan their activities to accommodate these responses. As such, liquid and transparent financial markets with low transactions costs are viewed as advantageous for demand side responses.

While a number of submissions were supportive of government playing a role in facilitating the development of DSM, it is noted by Origin and TRUenergy that a case for government intervention to deliver DSM in the small customer segment has not been made, particularly with respect to remote load control.

Origin contends that the large customer segment should remain the target of government efforts to increase the uptake of demand side opportunities arguing that there is considerable work that could be done to increase awareness of the benefits of DSM in the large customer segment with much greater benefits to be captured compared with the residential sector.

Submissions on the discussion paper also raised the current ‘D-factor’ incentive arrangements taking place in NSW. It is noted that this is essentially an incentive arrangement via IPART for distribution companies to promote the consideration of DSM in network planning. It has been suggested in submissions that this could add value at a national level.

Analysis

In theory, the supply side and the demand side receive appropriate price signals in the NEM. In practice, many factors militate against demand side response.

- Customers are generally small in relation to generation and their core business is not electricity. Demand side response is inherently more difficult to organise, with high transaction costs. Further, customers have different priorities.

- Generators can participate directly in the spot market and the contract market. In theory so can the demand side, but in practice it is much harder. This is due to financial services licensing requirements and high transaction costs. Further, there is a lack of understanding by end use customers of the full value available from demand side response.
It is often difficult for the demand side to be unconditionally firm, and there are often constraints (e.g. demand deferral for up to 4 hours). However a portfolio of customers can offer greater firmness. Larger customers typically receive half the pool price saving for reducing their demand. As this is not firm, the customer is unable to access the contract premium. Typical customer benefits would be perhaps 10-20% of the maximum benefit for firm demand side.

Generation volumes are readily established, while the quantum of demand reduction is difficult to establish.

In practice the demand side participates through intermediaries. The retailer is in the strong position here as no other intermediary can readily capture the energy market benefit of demand reduction. However there is limited competitive pressure in this specialised area. There are significant transaction costs for retailers to target customers with demand response. This adds an additional layer of complexity which is only justified for interested customers with substantial demand capability.

Retail price caps impede demand response in the short, medium and longer term as they support cross subsidies between customers.

Network participants lack the incentive to pay for a demand service. Indeed it could be argued that transmission companies could have an incentive to discourage demand side response as they are earning TUOS income.

For some demand side response – where distribution companies exercise control over voltage, there is no obvious way of capturing the benefit financially.

It is much more difficult for the demand side to participate in the provision of reserve in the spot market than for generation.

One of the few areas where the demand side is advantaged by market arrangements is in its ability to bid to sell reserve capacity to NEMMCO at times of predicted shortage, which in itself is a market intervention.

In practice, by taking a fixed price tariff, customers can insulate themselves from the spot price. This means that specialised demand side products need to be applied. For small customers, achieving a demand side response is no simple matter. Unless customers are exposed to the benefit of reducing consumption at peak times, they have little incentive to respond.

Short term demand side response can be defined as changes in electricity usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high market wholesale market prices or when system reliability is jeopardised (United States Department of Energy, 2006).

In electricity markets, demand side response is traditionally associated with two approaches: exposing end users to prices and allowing consumers to choose their preferred level of consumption in light of the true costs of consumption (‘price based demand response’); and secondly, attempts to develop manual or automated responses through enabling technologies, such as smart meters or commercial intermediaries, such as aggregators (‘incentive based demand response programs’).
Price based demand response is of limited effectiveness in delivering an immediate response to spot prices, especially for small customers for the reasons outlined above, and particularly in the absence of smart metering of consumption. Consequently, incentive based demand response programs may have attractions in these cases.

DSM that has developed at this time has been focused on the large customer segment. The quantum of demand side response in the NEM currently is believed to be around 700 MW. Figure 31 shows an estimate of DSM in different industries. The actual demand side actually called at times of high prices is less clear.

31 Demand side management by industry

![Demand side management by industry](image)

Source: KPMG / Fraser Consulting

While the results so far from DSM in energy are only fair, there is some demand side activity in the large customer segment. It is also unclear as to the appropriate role that governments could usefully play to further stimulate this segment of the energy market.

For small customers the position is quite different. Voluntary or manual control, a possibility if difficult for large customers, can be dismissed as impractical for small customers except at the margin. Even with smart metering, which, as noted by the Productivity Commission in its Review of Private Cost-Effectiveness of Energy Efficiency, should provide better information contributing to enhanced consumer energy efficiency in peak periods, the barriers to participation will still be significant.

As such, significant participation of small customers in DSM initiatives can not be expected without automation. This means some form of remote or automated control of key appliances (e.g. hot water, fridges, freezers, air-conditioners, washing machines) would
be necessary to significantly influence peak demand. A similar approach seems also to be required for all but the largest commercial and industrial customers.

Control of appliances at key times would need to be activated by a smart device at the customer’s premises and a third party aggregator. There is a history of remote control of hot water units by distribution companies in many parts of the world including in NSW and QLD. Wider control programs have been put in place by some utilities in the USA.

Such a program targeting small and medium sized customers would require a control device to be installed in appliances and a supporting control infrastructure.

In the NEM it is unclear which party has an incentive to drive such a program. Retailers have short term contracts with customers and little ability to influence the development of appliance controls. Distributors have simplified business models based on regulatory drivers. A specialised intermediary would face similar issues to a retailer and in addition would have difficulty in capturing the trading benefit. There may be a case for government involvement to stimulate the demand side for small customers. This would involve the development of a framework whereby customers, market participants and intermediaries can benefit from demand side activity.

Specifically, government could develop a plan for automation of the demand response when spot prices are high for smaller customers.

Other policy options include:

» providing a reserve price signal – inconsistent with the basic market design, and should only be considered if other policies have failed;

» increasing the value of VoLL – a possible longer term option but in the short term may cause over-investment in peaking capacity; and

» creating a framework where intermediaries (e.g. distributors, network service providers, demand side specialists, or telecommunication companies) can better capture the benefit of demand side.

However, further work is required to identify the merits of these approaches and their costs and benefits.
ERIG findings and recommendations

Demand Response

» While some progress has been made, the demand side in the NEM is relatively inactive compared with its potential. Achieving its potential would drive major benefits in the NEM.

» To achieve these benefits, further work is required to develop a framework whereby customers, market participants and intermediaries can benefit from demand side activity.

» In the large customer segment, while progress has been only fair, there seems to be little basis for a policy response.

» The commitments made by state and territory governments to remove retail price controls will be helpful when implemented in supporting cost reflective prices and demand response.

» The work program of the MCE on demand side response and the progressive rollout of electricity smart meters from 2007 provides a further building block and is to be encouraged.

» The development of automated DSM for small and medium customers is probably required to further encourage DSM but may not develop without initial sponsorship by governments and supportive changes in the institutional arrangements to ensure that incentives can work in practice.

ERIG recommends that the MCE develop a strategy for automation of DSM suitable for application to small customers; and review the institutional arrangements to ensure that participants can capture the benefits of DSM and drive the DSM development process.

Government and regulatory issues

ERIG focused its attention on six specific government and regulatory issues impacting financial market trade. These were: ETEF in NSW; LEP arrangements in Queensland; retail price caps; carbon and renewables policy; the Financial Services Reform Act; and compliance with international accounting standards under the Australian Accounting Standards Board (AASB).

Detailed discussion regarding retail price caps is found in Chapter 5. The remaining five areas of investigation are detailed below.

Electricity Tariff Equalisation Fund

ETEF commenced on 1 January 2001 and provides electricity to NSW Government owned retailers at a fixed price to enable those retailers to supply regulated retail customers without trading risk. The volume of electricity supplied under the ETEF exactly matches the regulated retail load.
Under existing legislation, ETEF is due to expire on 30th June 2007. The NSW Government has decided to extend this expiry date to allow adequate time for adjustments to occur in the energy trading market. ETEF will now be phased out gradually between September 2008 and June 2010. The phasing out will be in accordance with the schedule detailed in table 14.

14 ETEF Phase Out Timeline

<table>
<thead>
<tr>
<th>Current:</th>
<th>ETEF supports 100% of NSW regulated retail load</th>
</tr>
</thead>
<tbody>
<tr>
<td>From September 2008:</td>
<td>ETEF supports 80% of NSW regulated retail load</td>
</tr>
<tr>
<td>From March 2009:</td>
<td>ETEF supports 60% of NSW regulated retail load</td>
</tr>
<tr>
<td>From September 2009:</td>
<td>ETEF supports 40% of NSW regulated retail load</td>
</tr>
<tr>
<td>From March 2010:</td>
<td>ETEF supports 20% of NSW regulated retail load</td>
</tr>
<tr>
<td>From June 2010:</td>
<td>ETEF supports 0% of NSW regulated retail load.</td>
</tr>
</tbody>
</table>


This phase out timeline has been communicated to the market.

Stakeholder views on ETEF

In its 2003 National Competition Policy assessment of NSW, the NCC argued that the operation of ETEF is likely to reduce liquidity in the NEM as retailers and generators have no incentive to contract for supplying load to customers under regulated tariffs. The NCC further argued that the increase in financial instrument prices pursuant to a decrease in liquidity increases the costs for new entrant retailers.

A clear majority of submissions argued that ETEF has adverse impacts on financial market liquidity. Further, it was emphasised that it is inappropriate for governments to protect public sector suppliers from the risks associated with a competitive market. While some stakeholders requested that the timetable for the phase out of ETEF be accelerated, the majority of market participants requested that the phase-out timeframe announced by NSW for the phase out of ETEF be adhered to.

Findings on ETEF

ETEF removes volume from the traded market and therefore has an adverse impact on financial market liquidity. This view was supported by the KPMG electricity trading study which notes that ‘the removal of ETEF will progressively add depth and significant liquidity in the NSW regional pool and more broadly across the NEM through inter-regional trading as generators and retailers substitute ETEF for bilateral arrangement’. As such, ERIG strongly supports the clear commitment the NSW Government has made to the phase out of ETEF. Accelerating the timetable for the phase out of ETEF is not supported as it could impact the hedged position of market participants who have made commercial decisions on the basis of the information communicated by the NSW Government.
Long-term Energy Procurement

The Queensland Government operates a regulated tariff support arrangement and employs a pricing and risk management framework known as LEP as part of its CSO payment arrangements.

With the sale of much of the Queensland Government-owned retail sector and the introduction of FRC, Queensland’s CSO arrangements will apply to a smaller number of customers.

Stakeholder views on LEP

The Queensland Government notes that unlike other non-market mechanisms e.g. ETEF, the LEP does not discourage government-owned retailers from entering into bilateral financial contracts with generators (either government-owned or private). As such, the Queensland Government argues that LEP sits outside the wholesale market and encourages retailers to manage their risk, which goes some way towards improving financial market liquidity.

However, some market participants claim that the LEP over-compensates retailers for procuring contracts (i.e. retailers have been able to negotiate contract prices below the benchmark price paid by government). As a result, it is argued that the additional revenue accruing to the retailers distorts their behaviour. Further, a number of market participants have commented that the LEP is an unnecessary government distortion in the market.

Findings on LEP

Firstly, ERIG is concerned about the lack of transparency associated with the LEP. No details are readily accessible to the market explaining the workings of the LEP.

Aside from this transparency issue, the ERIG holds concerns that the LEP is an unnecessary market distortion that potentially has adverse impacts on the market. This view was supported by the KPMG electricity trading study which notes that ‘the removal of LEP and sale of retail assets will contribute liquidity to the financial markets over time’. As such, the removal of the LEP is strongly supported.

Carbon and Renewable Energy Policies

The proliferation of carbon and renewables policies across governments has previously been recognised as an impediment to efficient investment activity (see Capital Markets discussion above and Chapter 5). These inefficiencies are also seen to have an adverse impact on trading in the contract market.

Stakeholder views on carbon and renewable energy

Submissions consistently raised significant concerns about the uncertainty associated with existing government carbon and renewable energy policies. These concerns have focused on the current proliferation of government renewable and greenhouse schemes. Investors argue almost unanimously that this situation increases regulatory risk which leads to inefficient investment outcomes.
Submissions also note that this promulgation of schemes and products adversely impact financial market liquidity as activity in these products is diluted. Further, concerns about the ‘rules of the game changing’ in regard to carbon and renewable energy policy e.g. baseload energy becoming less competitive if a national carbon tax was introduced means some market players are reluctant to enter into longer term energy contracts. This uncertainty is contended to be a factor which constrains the forward market and market liquidity.

Findings on carbon and renewable energy policies
ERIG notes the inefficiencies occurring through the proliferation of existing government carbon and renewable energy policies. This fragmentation of schemes and products adversely impacts financial market liquidity and is brought to the attention of governments.

The Financial Services Reform Act
The amendments to the Corporations Act introduced in March 2002 by the Financial Services Reform Act, extended the insider trading legislation and therefore the disclosure principles expected from securities and equity related futures products to electricity derivatives contracts.

ERIG notes that there are two key areas of uncertainty associated with the new disclosure requirements under the FSR Act. These are: disclosure of OTC transactions; and disclosure by generators of their short term availability.

It has been suggested that the market may not be complying with the requirements of the FSRA. If this were correct, educational activity by ASIC would be indicated.

Stakeholder views on the FSR Act
Submissions were mixed in their views on the importance of resolving FSR Act issues. While some stakeholders were firmly encouraging any clarity that could be provided from ASIC regarding application of FSR Act to the energy market, other stakeholders argued that the FSR Act was not a major issue.

Some submissions raised concerns about the additional compliance burden incurred through the increased regulation associated with the FSR Act amendments. This was offset by comments from market intermediaries that the transparency achieved through mark-to-market positions and counter party exposure would provide better insights to how companies are managing risk.

Energy market participants have also raised concerns about the relevance of the full range of obligations and compliance associated with the licensing requirements of the FSR Act. It has been argued that these are not sufficiently tailored to the real risks associated with trading in the wholesale market with relatively sophisticated counterparties. This constitutes a barrier to entry to participation in the wholesale market and a cost burden on smaller generators, start-up retailers, and demand side participants. It has also been cited as a concern impeding the development of derivatives in the gas market.
Findings on FSR Act

The industry’s uncertainties associated with its disclosure requirements under the FSR Act are noted. This is an issue that could be resolved through clarification from ASIC of the FSR Act obligations of industry. The MCE is the appropriate body to approach ASIC on this matter.

Further, ERIG notes industry concerns regarding the relevance of all the obligations of the FSR Act. As ERIG has had limited opportunity to analyse this issue in any depth, it is considered that this issue should be further investigated by the Corporations and Markets Advisory Committee (CAMAC) and ASIC and the energy industry.

International Accounting Standards - AASB 139

In 2004, the AASB harmonised Australian accounting standards with the International Financial Reporting Standards. AASB 139 requires companies’ hedging arrangements to pass an effectiveness test to qualify for hedge accounting. Qualification for hedge accounting is based on an expectation of future hedge effectiveness (prospective) and an evaluation of actual effectiveness (retrospective). If the arrangements fail the test, they must be ‘fair valued’ or marked to market, and recorded in a company’s profit and loss account.

The problem for Australian electricity companies is that nearly all their dealings in the NEM can be classified as hedging arrangements for the purposes of AASB 139. However, options are unlikely to meet the requirements of the hedge effectiveness test. This accounting practice potentially introduces considerable volatility into the profit and loss (P&L) statements of listed companies.

An outcome of this treatment is that market participants may seek physical hedges (e.g. vertically integrate), not in order to manage price exposure, but to avoid a volatile P&L. This strategy could subsequently reduce liquidity and encourage a situation where commercial risk management is influenced by accounting implications.

Stakeholder views on AASB 139

AGL and TRUenergy raised concerns about AASB 139 distorting participant activities as they seek to avoid earnings volatility.

Findings on Accounting Standards

ERIG notes industry concerns created through the interplay of requirements under AASB 139 and the gross pool characterister of the NEM.

While broadening the categories of allowable instruments under AASB 139 to meet the characteristics of the NEM would appear attractive to some parts of industry, it is understood AASB 139 is complying with an established international standard and as such, this outcome would be difficult to achieve.

Further, the KPMG electricity trading paper notes that ‘there is no evidence that the adoption of a new accounting standard for financial instruments is impacting on market liquidity’. There appears to be little reason for any recommendation in this area as this is an issue for industry to address.
ERIG findings and recommendations

Government and Regulatory Issues

There are a number of areas where Governments and ASIC could consider action to better support and remove barriers to the development of more efficient financial markets, thereby fostering reduced risk premiums.

ERIG recommends that:

- The NSW Government remove ETEF in accordance with the timetable it has communicated to the market.
- The Queensland government phase out or abolish the LEP.
- ASIC clarify to industry participants their obligations under the FSR Act.
- CAMAC, in consultation with the industry and large DSM customers, review its requirements under the FSR Act for wholesale participants in the energy markets keeping requirements to those relevant and necessary.
- CAMAC, in consultation with the gas industry, considers the FSR Act obligations to ensure that they do not impede the efficient development of financial markets in gas.

Gas Financial Markets

The origin of Australia’s gas industry lies in state-based markets with legislative and regulatory barriers restricting trade between the states. Unlike the electricity industry, the gas industry has been largely privatised and until recently designed to service an energy market entirely unlike what we see today.

Essentially single basin suppliers serviced single state-owned (or in the case of AGL private) monopoly distributor-retailers and e-owned generators. ESSO / BHP supplied the SECV and the Gas and Fuel Corporation in Victoria. Moomba serviced ETSA in SA and AGL in Sydney largely through single pipelines. North West Shelf partners supplied the WA market. Private pipeline owners developed a series of different access regimes.

Reforming the gas industry in Australia since the mid 1990s has involved the removal of some of these legislative and regulatory barriers to trade, in addition to the separation and ring-fencing of transmission and distribution functions from the contestable upstream and downstream elements.

Although these reforms have been pursued and implemented to varying degrees with a spot market initiated in Victoria, the gas industry is still characterised by a small number of large players supplying gas and managing risk under long term and often restrictive contracts.

The Australian gas market currently has three regional segments, the Eastern gas market, the Western Australian market and the Northern Territory market. The eastern gas market has three major retailers, few major transmission pipeline providers and limited gas storage facilities. It has three major gas producers.
The arrangements were suited to that environment prior to a decade ago, but market changes now demand (and have commenced delivering) a more flexible industry to accommodate gas retail competition, new gas producers including the supply of CSM gas, and increasing use of electricity generation from gas as depicted in Figure 32.


However, these developments need greater consistency in access arrangements between pipelines, more spot price transparency, and a transition to contract types which support the on-trading of gas given the small volume of gas trading, currently 5-10 trades per year (KPMG).

The NEM is rated well by participants and by ERIG, but the gas financial market is immature and is criticised by retailers seeking to enter new markets and new gas fired generator proponents.

Figure 33 shows gas basin and gas pipelines in Australia as at 2006.
The Work of the Gas Market Leaders Group

The MCE established the GMLG comprising 12 members, representing each sector of the gas market and gas users in December 2005. The GMLG had an objective to promote a 'competitive, reliable and secure natural gas market delivering increased transparency, promoting further efficient investment in gas infrastructure and providing efficient management of supply and demand interruption.'

Released in July 2006, the GMLG market development plan proposed seven recommendations to achieve this objective:

- the establishment of a Bulletin Board (BB) covering all major gas production fields, major demand centres and transmission pipelines;
- the development of a detailed design of a Short-Term Trading Market (STTM);
- the release of an annual gas supply and demand forecast produced by a Gas Market Operator (GMO);
- the formation of a GMO to manage both the wholesale and retail gas markets throughout Australia as well as administer the BB and, if progressed, the STTM;
- the GMO would support the National Gas Emergency Response Advisory Committee (NGERAC) in the collection, maintenance and publication of analysis of the gas system and technical advice during a gas supply constraint;
- the development of wholesale and retail market rules by the GMO with the AEMC to approve the rules; and
- the joint funding of the Plan’s initiative by industry and government with the continuation of the GMLG until the GMO is established, to ensure the recommendations are progressed.
The establishment of a BB and STTM for gas is envisaged to improve short-term trade in
gas at hubs, and the development of a secondary market in gas transmission capacity.
These developments represent important initiatives.

However, there are other impediments to the gas market that require attention. Addressing
these impediments will allow the gas market to improve their efficiency.

Potential impediments to the gas market include the joint marketing of gas by producers,
inconsistencies in rule making and open access regimes to gas pipelines, intervention by
governments in emergency situations, lack of a single gas market operator, and the lack of
standardised and fungible gas contracts.

Joint marketing
Gas exploration is very risky with a low probability of success on any individual drilling. Joint
ventures are mechanisms by which participants to the venture can share these risks.

Gas exploration and production has historically been carried out under joint marketing
arrangements. For example, the Cooper Basin joint venture includes Santos, Gradav Limited
and Origin Energy as participants. The Gippsland Basin involves Esso and BHPB, and the
Bowen/Surat Basins has Santos and Origin Energy as joint stakeholders. BHP Billiton,
ExxonMobil, Santos and Origin Energy account for 93 per cent of the upstream gas market
in Eastern Australia.

Joint marketing often involves common terms and conditions such as pricing which may
lock up the potential to implement short term balancing arrangements, and hence extract
optionality, for efficient re-trading of imbalances. This potential inefficiency is recognised.

Joint marketing has been considered previously by the Upstream Issues Working Group
(1998). Parer also considered this issue in 2002. Both reviews expressed the view that a
longer-term policy objective is to promote separate marketing where feasible. As KPMG
note “there is merit in reviewing the current prevalence of joint marketing arrangements
which may restrict competition”

Gas transmission
Open access to gas pipeline infrastructure assists upstream and downstream competition
by introducing inter-basin competition for downstream users. The National Third Party
Access Code for Natural Gas Pipeline Systems is applied by regulators and imposed on
pipeline providers. This regulatory access regime is with a few exceptions applied across the
gas market.

Standardisation
The lack of standardised and fungible contracts in the gas market has impeded the
development of trade and liquidity in gas related financial markets. Legacy long-term
contracts underpinning investment are generally of point to point design and are only
progressively being replaced with flexible contracts with multiple delivery points. KPMG
reports that ‘the absence of standardisation in the in the gas market is detrimental as it limits
the efficiency of the physical market and the lack of homogeneity impacts the ease with
which participants are able to execute trades. Consequently, this hinders the development
of related financial markets’.
Differences in the rules across jurisdictions also impede short-term trade in gas and may present barriers to entry. Further, participants report that pipeline access through multiple pipelines is difficult and time consuming.

**Emergency intervention**

The potential for intervention by governments in emergency situations creates uncertainties for stakeholders and crowds out market based solutions for such contingencies. Evidence of such intervention includes the recent Moomba emergency.

**Single market operator**

At present, VENCOrp is the only gas market operator that administers the spot market operating in Victoria. REMCo and GMC also operate gas markets. However, there is the potential for a national gas market operator to facilitate spot market trade on a much grander scale should the market mature sufficiently. Indeed, this is the perspective of the GMLG and is reflected in its specific recommendations.

**Rule making**

Given the prospects for the convergence of gas and electricity markets, it is evident that the rule making processes should also converge. For this reason it may be appropriate that the AEMC undertake assessments of rule changes in the operation of the gas market so there is consistency in the rules across the energy markets.

**Stakeholder views on the gas market**

Energy Australia and the ERAA state that financial markets for gas are almost non-existent with trading limited to scheduling long term supply contracts on the delivery day and a lack of standard contracts.

There is support for the work of the GMLG from Energy Australia, the ERAA, the Western Australian Office of Energy, The Australian Petroleum Production and Exploration Association (APPEA) and TRUenergy, noting that it should introduce some transparency. However, the EUAA notes that returns are likely to be modest and it is unlikely that the work of GMLG will significantly impact on the drivers for financial trading of gas in the medium term. Some argue that the most important changes required relate to facilitating upstream competition including the effective regulation of pipelines with market power.

The Australian Pipeline Industry Association (APIA) is not supportive of radical gas market reform as market risks are underpinned by long term bilateral contracts which should not be undermined by pressures to unwind them for the sake of developing short term markets. APIA supports the concept of standardisation across the gas market. REMCo is also supportive of this and believes that the lack of standardisation across gas markets (as a barrier to entry) is one of the matters that the industry intends to address with a STTM. TRUenergy also supports standardisation but not through regulatory means, as the standardised processes should naturally emerge in the gas markets.

TRUenergy believes that changes to joint marketing would substantially increase competition in the domestic gas market. The Energy Action Group states that the GMLG recommendations should also be encouraging upstream inter basin competition, competitive gas transmission and distribution along with the downstream retail sector.
APPEA argues that the current acreage management regimes are appropriate and effective as they ensure the security of tenure of discoveries which may become commercially viable in the future. In relation to joint marketing, APPEA considers an appropriate way forward is to adopt an approach that facilitates separate marketing arrangements while maintaining the capacity for industry to utilise joint marketing arrangements. Finally, AGL supports the findings with respect to the gas market.

ERIG findings on the gas market

The Australian gas market is still maturing and is of growing importance for power generation. As such, competitive pricing and supply reliability are increasingly significant matters. Equally important is that retail competition is impeded by the difficulty of transacting in the gas market.

Financial markets relating to gas are yet to develop, besides those in Victoria which are still limited, although recent work by the GMLG in its National Gas Market Development Plan suggests that a bulletin board and a short term trading market will shortly be established. This is expected to facilitate price transparency in this market, encourage investment and development of Australia’s gas resources, and improve the ability of end users to negotiate competitive gas contracts.

However, the impact of these developments on financial market liquidity and the efficiency of the gas market are expected to be limited if the impediments to gas market trading are not removed. Important changes to the gas market that will enhance its competitiveness and efficiency are therefore required. This may include changes that will facilitate more upstream competition, downstream competition and effective regulation of pipelines with considerable market power and the continued development of the gas market. The recent establishment of the MCE and Ministerial Council on Mineral and Petroleum Resources Joint Working Group on Long Term Natural Gas Supply is noted.

In relation to the establishment of a separate gas market operator, there seems to be merit in the creation of a national energy (electricity and gas) market operator (see also Chapters 5 and 6). However, in recognition of the differences between the governance arrangements for the proposed gas market operator and NEMMCO, implementing this objective would require a review of the governance arrangements for a proposed national energy market operator. In order not to slow down the existing momentum for gas industry reforms, decisions to progress a gas market operator should sensibly take account of the longer term objectives for a national energy market operator.

It also seems logical that the AEMC should assess gas market rule changes including rules surrounding emergency intervention and consistent arrangements for an open access regime to gas pipelines be implemented.

The developments raised here seek to remove impediments to the gas market and which would contribute to the standardisation of market structures, rules, conventions and systems. This would then allow for the emergence of standardised and fungible gas contracts.

There is evidence of a drive toward standardised gas ISDA contracts. This has been precipitated by the ongoing work of associations such as AFMA and should be supported by government and industry alike.
Before standardisation can prevail, gas producers, gas pipelines, and market systems must become increasingly flexible to transition to a standard which allows for gas financial markets to emerge and mature. Such flexibility can only be achieved if these impediments raised here are removed.

**ERIG findings and recommendations**

**Gas Financial Markets**

The GMLG recommendations offer worthwhile progress and are generally supported.

**ERIG recommends that the MCE:**

- Provide the necessary support for the timely implementation of the GMLG recommendations including supporting the establishment of a National Gas Market Operator (GMO).

- Ultimately oversee the merger of the GMO with NEMMCO after NEMMCO’s governance has been modified as proposed elsewhere. Resolution of this matter should not be allowed to impede the development of a national gas market operator.

Greater standardisation of market structures, market processes, pipeline access and supply points for pricing across the market is required.

Further work is required to assess the upstream areas of acreage management and joint marketing.

**ERIG recommends that the GMLG, or a successor group, develop an implementation plan for the standardisation of market structures, rules, conventions and systems in the gas market.**
8 The benefits of market reform

Overview

Economic analysis has shown that the potential resource savings within the bulk electricity sector flowing from moving to a fully efficient market would reduce the total economic costs of supplying electricity, within the NEM, by between $200 to $300 million per year over the longer term, compared with ‘business as usual’ (BAU) market outcomes. Reforms to the bulk electricity sector that also flow through to the distribution sector could result in additional cost savings of around 10 per cent in the medium to long term.

In addition, prices at the wholesale level in a fully efficient electricity market would initially be around 10 per cent lower compared with the BAU scenario. This benefit represents both lower production costs and increased competition.

Across the three areas of reform modelled at the electricity sector level for the NEM, 80 per cent of the benefits are derived from improved competitive outcomes, 13 per cent from improved demand side response, and the remaining 7 per cent from improved transmission planning.

Early investment in transmission expansion where economically warranted, approximating partial implementation of a ‘free flowing’ network, provides relatively modest net economic benefits (in the form of cost savings), but only amounting to around 1/6th of the benefits that could be achieved through reforms focussed on developing a fully efficient market. Moreover, even after accounting for paying for these transmission upgrades, total expenditure on electricity by consumers is estimated to increase under this scenario.

At the economy-wide level, the long term benefits flowing from more efficient operation of the electricity sector include an increase in real GDP of around $400 million per annum.

Over the longer term, prices at the household level to consumers in a fully efficient electricity market are estimated on average to be around 2% to 3% lower. Household prices may fall a little further than this initially.

Expected benefits of reforms: electricity sector

ERIG commissioned McClennan Magasanik Associates (MMA) to estimate the economic savings at the electricity industry level of the reforms discussed in this report. It is difficult to make any informed assessment about the performance of the WEM at this early stage (the Wholesale Energy Market commenced operation in Western Australia in late September 2006). Accordingly, the modelling is restricted to the NEM. To the extent that scope emerges to improve the efficiency of the WEM over time, the potential benefits from reform across all of Australia will be larger than those reported below.
Electricity sector benefits: better-timed investment savings

To provide a benchmark for the total value of potential reforms, MMA prepared an ‘Efficient Development’ scenario that is designed to model the cost of delivering electricity to meet projected demand by approximating the efficient planning path when both transmission and generation investment requirements are jointly considered. This scenario also included assumptions relating to improvements in the level of competition in the spot market and improvements in DSM response.

This was compared to a BAU scenario which represents the market developing in accordance with recent and current trends for pricing and investment. This scenario provides a reference case against which to compare changes from current practices. MMA modelled the scenarios for the period 2006-07 to 2024-25.

The economic analysis demonstrates that the ‘efficient development’ scenario generates benefits to the electricity sector of about $200 million per year initially, rising to well over $300 million per year over the next ten years, before declining again to around $200 million. The decline reflects the assumption that the market becomes more competitive during this period as new entrants participate in the market (see figure 34 below).

These benefits take the form of cost savings due to improved demand side response and more efficient pricing leading to reduced capital expenditure from deferral of new generation. These savings represent around 4 per cent of the annual costs of the generation sector in meeting the demand for electricity.

The analysis of the scenarios has also considered the impacts of alternative developments on the long-term average cost of electricity to customers based upon the spot market prices and the costs of the additional transmission developments. It was estimated that prices at the wholesale level initially would be nearly 10 per cent lower, on average, across the NEM. The larger decline in prices than in costs at the wholesale level reflects the increased competitive outcomes under the ‘efficient development’ scenario as modelled by MMA.

If the new generation plants in the ‘efficient development’ scenario that are required to meet demand growth are only developed by the incumbents assumed to operate in the BAU scenario (ie, there are no new competitors in the market), then the benefits of ‘efficient development’ relative to BAU do not fall post 2015 and the annual economic benefits settle at around $300 million per year in real terms up to 2024-25. If this situation applies, the price reductions would not be as large as reported above due to lower levels of competition.

Impact of early transmission augmentation

To assist with ERIG’s consideration of the benefits and costs associated with developing a ‘free flowing’ transmission network, MMA developed a scenario where transmission augmentation within BAU was advanced ahead of schedule (but only when it is ‘economic’ – defined as when the economic benefits exceeded the costs). This scenario, referred to as the Transmission Augmented BAU (or TABAU), was intended to estimate and contrast the additional economic benefits of reducing certain inter-regional constraints such as the upgrade of QNI, the Heywood Interconnection and Snowy to Melbourne.
Compared with BAU, early augmentation of the transmission network (TABAU) offers modest net economic benefits in the period from 2011 to 2021, averaging approximately $38 million per year in real terms (see figure 34). These modest benefits arise from more efficient dispatch and a higher level of competition between regions. By 2020, it was assumed that the main interconnectors would be upgraded under the BAU conditions, and there were no additional benefits relative to BAU from that year onwards.

The benefits achieved under early augmentation represent about 19 per cent (on average) of the potential longer term benefits that could be achieved with efficient development over the same period. This is because, under the efficient development scenario, transmission augmentations would be planned in a manner that captures both optimisation of transmission expansion and generation expansion and would be timed to occur in order to maximise net economic benefits across both. Over the period shown in figure 34 average benefits occur later under the ‘efficient development’ scenario than under the TABAU scenario.

34 Annual benefits of reform relative to BAU assumptions

Price Impacts

MMA also assessed the initial impacts of alternative scenarios compared with BAU on the long-term average ‘price’ of electricity. This ‘price’ is based on spot wholesale market prices and the costs of both transmission developments and infrastructure investment for enhanced demand side response. Relative to the BAU scenario, these ‘prices’ under the ‘efficient development’ scenario are estimated initially to be approximately 10 per cent lower across the NEM at the wholesale level (see figure 35 below).

In contrast, the ‘Transmission Augmented BAU’ does not result in reduced costs to consumers in most NEM regions (see figure 35). This is because although the transmission network has been expanded with an additional 300 MW of capacity between Victoria and
South Australia, 600 MW of capacity between Snowy and Melbourne, and a 400 MW upgrade of QNI, this is insufficient to prevent generators from acting in a manner which would shift prices away from their efficient level through the exercise of transient market power. As a result, the total costs to consumers rise by around 2 per cent on average (with the exception of Queensland where costs fall 1 per cent) under TABAU relative to BAU when the costs of the augmentation are included.

35 Levelised time weighted ‘prices’ by region

Augmenting the transmission system as soon as possible under TABAU provides benefits through reduced costs for a number of years from 2011 onwards. However, according to MMA, because the major generation portfolios are estimated to still be able to support prices reflecting transient market power in importing regions (and with higher prices in exporting regions due to the increased generation requirements in the short-term until new capacity is built), there is no guarantee that a major reinforcement of the transmission system alone would provide large benefits to customers. MMA is of the view that it is more likely that the majority of the benefits would accrue to generators rather than to customers.

MMA noted that comparing ‘price’ impacts under BAU with ‘efficient development’ may give the impression that NSW is not as far from the economically efficient price outcome relative to Queensland and Victoria as might be expected, given recent historical outcomes (as discussed in Chapter 4 above). However, MMA further stated that ‘these scenarios should not be relied upon to make such assessments’ over time ‘because of the difficulty of predicting the evolution of market power in future under BAU conditions’. In particular, MMA concluded, under BAU conditions, that ‘it is very unlikely that NSW prices would be lower than shown’. To this end, the appropriately conservative approach to modelling suggests that potential benefits could be higher than reported by MMA.
The structure of cost savings: electricity sector

The structure of the additional costs and offsetting cost savings across three sub-periods to 2024-25 arising from a fully efficient market at the wholesale level are shown in table 15 below.

15 Structure of cost saving with Efficient Development

<table>
<thead>
<tr>
<th>Cost Component</th>
<th>Early to 2013</th>
<th>2014 - 2018</th>
<th>Later than 2018</th>
</tr>
</thead>
<tbody>
<tr>
<td>Variable O&amp;M</td>
<td>$9</td>
<td>-$11</td>
<td>-$18</td>
</tr>
<tr>
<td>Coal Cost</td>
<td>-$55</td>
<td>-$129</td>
<td>-$272</td>
</tr>
<tr>
<td>Gas Cost</td>
<td>$203</td>
<td>$201</td>
<td>$29</td>
</tr>
<tr>
<td>Fixed capital and O&amp;M</td>
<td>$75</td>
<td>$453</td>
<td>$675</td>
</tr>
<tr>
<td>Demand side response</td>
<td>-$36</td>
<td>-$200</td>
<td>-$234</td>
</tr>
<tr>
<td>Total</td>
<td>$195</td>
<td>$313</td>
<td>$179</td>
</tr>
</tbody>
</table>

1. A minus sign denotes a cost increase.

It is estimated that a major proportion of early benefits in the ‘Efficient Development’ scenario would be realised by reduced gas consumption and a greater participation from demand side response in meeting infrequent and extreme peak demands leading to savings in generating plant investments. Achieving demand side response requires additional capital expenditure to achieve this benefit and this shows up as an additional cost in table 15.

In the longer term the main source of industry level benefits identified is from reduced capital expenditure associated with deferment of new generation plant and the change in the fuel mix following the switch to more coal fired development and reduced savings in gas fired generation. The increased contribution from demand side responses provides a substantial saving in fixed costs for new generating plant.

Disaggregating the cost savings

The benefits arising under the ‘efficient development’ scenario are associated with three potential areas of reform:

- improved capital productivity through improved competitive behaviour (associated with modelling ‘perfect competitive behaviour’ through short run marginal cost bidding);
- improved transmission planning through approximating the efficient planning path when both transmission and generation investment requirements are jointly considered, leading to an optimal mix of generation and transmission; and
- the benefit of a more efficient mix of demand side response and gas turbine plant.

MMA undertook sensitivity analysis around these three drivers in order to disaggregate the long term annual benefit of $200 to 300 million identified above. In each assessment, MMA considered two outcomes in order to provide an estimate of the upper and lower bounds of the potential impact of each driver. These are discussed further below.
Improved capital productivity

MMA assessed the resource savings associated with more competitive behaviour by reconsidering the BAU case with short-run marginal cost bidding to represent a perfectly competitive outcome. This was contrasted with consideration of the ‘efficient development’ scenario where the bids of the generation portfolio were derived from the BAU case. In both of these sensitivity assessments, no changes in the timing of new entry or transmission upgrades were considered.

Improved competitive outcomes leads to more efficient use of existing resources. This reduces the need for the same amount of investment that would be required in the absence of efficient use of invested resources.

The annual resource savings from these competitive outcomes, relative to the ‘efficient development’ and BAU cases, are shown in figure 36. The resource savings were estimated to be $160 million per annum for the adjusted BAU case and $129 million per annum for the adjusted ‘efficient development’ case. These values indicate the substantial economic benefits of more efficient bidding and dispatch. Improved competitive behaviour represents the major share of the potential cost savings in a reformed electricity market, comprising up to 80% of the potential value of reform.

36 Resource savings due to improved competitive outcomes

The improved competitive outcomes will also lead to lower prices for consumers, and subsequent additional economy wide benefits. These benefits are not included in the estimated resource savings above but are considered in the economy wide analysis below.

Impact of improved transmission planning

An upper and lower bound for the benefit arising from a more efficient mix of generation and transmission infrastructure associated with improved transmission planning was assessed by comparing two cases:
the efficient development scenario was modified to include the transmission plan associated with the BAU scenario. By comparing the costs of this case with ‘efficient development’ an assessment of the potential additional costs that arise from inefficient transmission expansion caused by market distortions can be made; and

modifying the BAU scenario with the transmission expansion plan associated with the ‘efficient development’ scenario. By comparing the costs of this scenario with BAU, an assessment of what improvements could be achieved from ‘efficient development’ but without changing the transmission development can be made.

In both of these cases the generation capacity expansion plan was re-optimised in response to the altered transmission plan. In essence, investment in additional generation would adjust the timing and size of additional plant in response to the changed market outcomes resulting from different transmission investments. The outcome of this would be that the timing of new generator entry would be brought forward in exporting regions with lower costs but delayed in importing regions with higher costs.

As with the transmission augmentation assessment under the TABAU scenario above, there are no net gains until early in the next decade, and these gains fall away early after 2020 as the mix of generation plant is assumed to be identical to the BAU scenario by 2022 (see figure 37). This is equivalent to a real benefit of approximately $16 million per annum.

In a similar manner, there are almost no net gains associated with modifying the transmission expansion path relative to the optimal path until late into the next decade. These gains also fall away quickly in the 2020s as before. The real net economic benefits associated with this sensitivity analysis average approximately $21 million per annum (see figure 37).

Overall, the impact of transmission distortion for the selected interconnection upgrades lies between approximately $16 and $21 million per annum which is up to 10 per cent of the potential value of further reform.

37 Impact of improved transmission planning
Impact of efficient demand side response.

The impact of the switch from open cycle gas turbine plant to efficient demand side peaking was evaluated by replacing the demand side response with open cycle gas turbines in the ‘efficient development’ scenario and adjusting the timing of interconnections where it is economic to do so. The BAU scenario was modified by adding in the identified demand side response under ‘efficient development’ and then delaying the open cycle plant and the Tomago combined cycle conversion to produce a sustainable price path.

The analysis of the impact of demand side response shows a gradual increase in net economic benefits starting from around 2011 for both sensitivity assessments (see figure 38 below). The increase in value over time is associated with the growth in the size of the market, and the ability of demand response to efficiently displace increasing volume of peaking plant associated with the larger market size.

38 Impact of improved demand side response

The value of improved demand side response can deliver up to 13 per cent of the value of reform on an annualised basis. That this value is similar for sensitivity analyses for both the BAU scenario and the ‘efficient development’ scenario suggests that the displacement of open cycle gas turbine plant with appropriate demand side resources has a value that is largely independent of other market factors.

To the extent that the total benefits under ‘efficient development’ reported above exclude local transmission and distribution reinforcement related to meeting extreme peak demands, the benefits from improved demand side response overall will be understated.

These benefits would also grow over time as new network developments are progressively deferred and replaced by suitable demand side responses. This analysis ignores additional benefits flowing from reduced investment requirements in the distribution and local transmission networks. Preliminary analysis by MMA suggests that, in present value dollars,
an additional $25 million per year could be achieved in the medium to long term. This may lead to a moderate increase of around 10 per cent in the real net benefits per year associated with improved demand side response.

Economy-wide benefits of electricity reform

The results presented above are confined to initial effects of reform within the electricity sector (and, in this case, within the NEM). These effects will have wider repercussions, affecting the entire Australian economy, over time.

Improvements in the efficiency of the delivery of energy to customers, together with the associated cost savings that release resources, such as capital and labour, to other economic sectors, will result in an increase in economic activity, incomes, real consumption and possibly investment through increased efficiency across the economy as a whole.

ERIG has worked in cooperation with the Productivity Commission in quantifying the wider economic benefits of electricity market reform. ERIG used the MMA analysis summarized above to obtain an approximate quantification of the initial electricity industry benefits (mainly cost savings) from an ‘efficient development’ scenario compared with a BAU scenario. This has been reported in this chapter of the report.

In order to avoid duplication of modeling effort, ERIG did not undertake its own general equilibrium modeling of the economy-wide benefits of electricity market reform. Rather, it passed the MMA modeling results to the Productivity Commission, which has been working on modeling the ‘outer envelope’ benefits of the National Reform Agenda (NRA). The Productivity Commission used energy market reform ‘shocks’ based, *inter alia* on the electricity market reform results advised by ERIG to estimate the economy-wide benefits of MMA reform scenario, using a version of the *Monash Multi-Regional Forecasting* (MMRF) modeling framework updated specifically for the Commission’s NRA study.

The electricity market reform ‘shock’ applied by the Productivity Commission included the impact of reducing the cost of supplying electricity from the generation sector by approximately $200 million per year, and associated lower energy prices to consumers over the long term.

Turning first to the benefits flowing from reduced requirements for capital in the electricity sector, economic output, as represented by real GDP, is estimated to be 0.02 per cent higher (about $200 million) over the longer term. As these reforms are concentrated in the highly capital intensive generation and transmission sectors of the electricity supply industry, and are predominantly associated with reduced investment requirements, the impact of the reforms is an almost negligible impact on the labour supply to other sectors of the economy. The increase in the supply of productive capital to other sectors of the economy, but limited change in labour supply to other sectors, results in real wages rising slightly as output expands.

These productivity benefits could be complemented by further benefits flowing from efficiency improvements through reductions in the exercise of transient market power in the economy.

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4 As noted in the previous section, at least 93% of the net economic cost savings is associated with reduced investment in generation capacity (and demand side response assisting this reduction) and around 7% of the total annual benefits is associated with improved transmission planning (and this will also include some impact on deferred generation investment). As almost the entire benefit is associated with deferred generation investment, the entire economic shock was modelled as a cost saving in the generation sector of MMRF, analogous to a total factor productivity shock in that sector.
electricity market and associated lower energy prices and effective increases in incomes. Drawing on the NRA assessment performed by the Productivity Commission, this is estimated to increase real GDP by a further $200 million per year.

Overall, therefore, the economy-wide benefits of the reforms presented in this report would increase real GDP by around 0.04%, or around $400 million per year. These benefits also include sustained price reductions to end-consumers of around 2% to 3% across the NEM over the longer term.

To the extent that (i) not all of the efficiency gains associated with improved demand side response are captured and/or that (ii) potential improvements in the retail or distribution sectors have been excluded, and (iii) that the benefits assessed go beyond the NEM scenario considered in this study, the potential benefits flowing from reforms across all of Australia and across all sectors of the electricity supply industry will be larger than those reported above.

Moreover, the analysis does not make allowance for ‘dynamic efficiency’ gains arising from more competitive markets, such as greater incentives for service providers to continue to improve their productivity and quality and to innovate to achieve a competitive advantage, and improved incentives for new efficient investment.

For all of these reasons, the economy-wide benefits of electricity market reform summarised above are likely to substantially understate the full gains potentially available from implementing reform.

Productivity growth is the key ingredient in promoting sustainable economic growth and improving the material living standards of Australians. Even small improvements in annual rates of productivity growth measured year-by-year, if sustained, add up to big improvements in living standards over time. For example, increases of around half a percentage point in annual rates of productivity growth raise average real incomes by almost 30 per cent over the next 50 years.

**ERIG findings**

Economic analysis has shown that the potential resource savings within the bulk electricity sector flowing from moving to a fully efficient market would reduce the total economic costs of supplying electricity, within the NEM, by between $200 to 300 million per year over the longer term compared with BAU market outcomes.

At the economy wide level, the long term benefits flowing from more efficient operation of the electricity sector include an increase in real GDP of around $400 million per annum.

Over the longer term, prices at the household level to consumers in a fully efficient electricity market are estimated on average to be around 2% to 3% lower. Household prices may fall a little further than this initially.

The economy-wide benefits of electricity market reform summarised above are likely substantially to understate the full gains from implementing reform, because they do not allow for other benefits not covered in the modeling analysis presented in this chapter, including ‘dynamic efficiency’ gains.
9 Energy reform as a process

Energy market reform and the NRA agenda

ERIG’s work on energy market reform cannot be viewed in isolation. It is one part—an important part—of COAG’s wider NRA.

As part of the NRA, ERIG has examined the economic efficiency of a fundamentally important enabling input—energy—into business activity and consumer well-being. It is no exaggeration to state that energy is a critical enabler for the operation of modern economies.

Energy market reforms over the past two decades have played a significant role in facilitating improvements in productivity and have underpinned Australia’s impressive economic growth.

Maintaining Australia’s energy sector’s performance

As noted in Chapter 1, energy market reforms by the year 2000 were estimated by ABARE to have resulted in an increase in national income of $1.5 billion. Australia has benefited from some of the lowest electricity prices in the developed world with industrial and household electricity prices 38 per cent and 31 per cent respectively below the average across the IEA countries.

These reforms produced one of the most competitive and efficient electricity markets in the world.

However, as detailed in this report, ERIG has found that more can be done to improve the efficiency of Australia’s energy sector (and to maintain the reputation of Australia’s energy sector as world leading) and to capture further productivity improvements leading to higher economic growth and living standards for all Australians.

Further reforms are essential if Australia is to attract the necessary investment required to meet its forecast energy requirements, particularly in light of the uncertainty associated with greenhouse and the complex technological responses which the greenhouse challenge is likely to demand of the sector.

Sustained productivity growth is also the key ingredient in promoting sustainable economic growth and improving the material living standards of Australians. Small improvements in annual rates of productivity growth measured year-by-year, if sustained, add up to big improvements in living standards over time. This is why it is so important to continue to improve Australia’s energy sector and to capture the estimated increases in real GDP of around $400 million per annum as identified in this report.
Current challenges: the need for market flexibility

In the process of conducting its review of Australia’s energy market, ERIG has observed that in a general sense, Australia currently faces challenges that could threaten its strong economic performance. At present, most of these are consequences of past and current economic and public policy successes. For example:

» Strong economic growth now has demand pushing up strongly against capacity limits, raising some concerns about cost and inflation pressures.

» Against that, strong commodity prices driven by the burgeoning economies of China, India and others have driven up the $A, put downwards pressure on manufactured product prices, and in the process have resulted in something of a ‘two-speed’ Australian economy, with strong competitive pressures on Australia’s non-commodity industries.

Dealing with these challenges, and sustaining strong economic performance and living standards, requires a renewed commitment to:

» enhancing economic efficiency on a nation-wide basis; and

» maximising the flexibility of Australia’s markets for goods and services.

That is the immediate focus of the NRA – and of the specific work of ERIG.

Energy reform as a process, not a one-off event.

ERIG recognises that its work was commissioned by COAG partly because of the lessons learnt from past economic and policy reforms. Whether the focus is energy market reform, or reform elsewhere, ERIG recognises that the right perspective is crucial. Building on the experience of the past, ERIG has recognised that economic reform should properly be viewed as a system of interrelated and integrated reform policies and processes.

Past experience tells us that economic reform is not a result of a one-off policy change in a particular area but more like a series of such changes, over time.

Accordingly, ERIG believes that setting up the conditions conducive to reform in the energy sector, as an ongoing process, is crucial for ensuring that Australia continues to have a highly efficient energy sector.

ERIG recommendations and ongoing reform

The recommendations of ERIG have been developed as an integrated package. They are intended to be implemented as a package because they are designed to be mutually supporting. For example:

» privatisation in the energy sector is intrinsically useful as a means of reducing barriers to market entry;

» it also removes potential for conflicts of interest and concerns by energy sector investors
about competitive neutrality. In that way it improves regulatory adequacy and enhances the prospects of getting good governance arrangements in place including ensuring that governments focus on their appropriate regulatory role, unencumbered by ownership concerns;

- planning across electricity generation and transmission, and from a market-wide perspective, is more likely to be effective with privatisation, and with good governance arrangements in place; and

- financial market efficiency is more likely to be fostered with improved arrangements surrounding inter-regional trading, more liquid gas markets, a more responsive demand side, improved settlement arrangements and reduced government intervention in areas such as retail price regulation.

ERIG’s concluding observations

If implemented, ERIG’s recommendations as a whole establish the foundations for an ongoing reform process that delivers substantial benefits to end users, where energy markets are encouraged to adapt flexibly to emerging market conditions.

Privatisation in the energy market is important. Without it, conflicts of interest will always threaten good governance and regulatory adequacy and perceptions of a lack of competitive neutrality between public and private investments will remain which will threaten efficient investment in the industry.

Market-wide and Australia-wide integration of both the competitive sector and transmission planning is vital. Without it, investment opportunities will be missed. Jurisdictional biases will continue and market efficiency will suffer.

Letting market price signals work is essential. Without them, especially in an energy-only market, much needed investment can be threatened. In some cases, those groups governments seek to protect will be most adversely affected by policies such as price caps. Financial market efficiency will be undermined as well and demand-side responses, crucial for energy market efficiency, will be very limited and national financial markets will be more limited than they need to be.

Finally, good governance is crucial to the ongoing success of the sector. It’s the key to embedding arrangements for ongoing reform processes. Without it, any given reform can be (and probably will be) progressively undermined over time.
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Appendix 1
ERIG’s Terms of Reference

ERIG terms of reference

At its meeting on 10 February 2006, COAG agreed that further reform of Australia’s energy sector would yield significant efficiency and energy security benefits.

COAG convened the Energy Reform Implementation Group (ERIG). ERIG was asked to report before the end of 2006 on reform recommendations for:

- achieving a fully national transmission grid including the most suitable governance and transitional arrangements having regard for COAG’s objective of achieving a truly national approach to the future development of the electricity grid, the legitimate commercial interests of asset owners, and the need to promote investment that supports the efficient provision of transmission services;

- any measures that may be necessary to address structural issues affecting the ongoing competitiveness and efficiency of the electricity sector; and

- any measures that may be necessary to ensure there are transparent and effective financial markets to support energy markets.
Appendix 2
Panel Members and Secretariat

ERIG panel members
ERIG was chaired by Mr Bill Scales AO. In addition to his role on ERIG, Mr Scales is also the Chancellor of Swinburne University and the Chairman of the Port of Melbourne Corporation and the Australian Safety and Compensation Council. Mr Scales was supported by:

- Mr David Swift, Chief Executive of the Electricity Supply Industry Planning Council of South Australia, who led the Transmission Work Stream;
- Mr Geoff Carmody, co-founder of Access Economics, who led the Market Structures Work Stream; and
- Mr Alan Rattray, former chair of the Southern Hydro Board, who led the Financial Markets Work Stream.

ERIG ex–officio panel members
- Dr John Tamblyn, Chairman AEMC
- Mr Steve Edwell, Chairman, AER
- Dr Brian Spalding, Chief Operating Officer, NEMMCO Company

ERIG secretariat
ERIG was supported by a small Commonwealth-State government secretariat comprising:

Marie Taylor (DITR)
Tim Mason (DITR)
Demus King (DITR)
Christopher Short (ABARE)
Alex Georgievski (AER)
Ross Mitchell (AER)
Nigel Johnston (Treasury)
Bede Moore (DITR)
Elena Bristot (DITR)
Peter Naughton (VIC)
James Benjamin (QLD)
Appendix 3
ERIG Reference Groups

For each of the three work streams: transmission; market structures; and financial markets; reference groups consisting of key industry and other stakeholders were established to provide advisory support to ERIG. An officials’ reference group (ORG), representing all jurisdictions, was also established to provide advice on key energy policy issues. The membership of ERIG’s reference groups is detailed below.

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Appendix 4
Submissions to ERIG & Expert Advice

Submissions to ERIG

ERIG released an Issues Paper for public consultation on 5 July 2006. 50 submissions were received on the Issues Paper. ERIG also released three Discussion Papers on 17 November 2006. 41 submissions were received on the Discussion Papers. The Issues and Discussion Papers are available at www.erig.gov.au. A list of the public submissions received by ERIG is detailed below.

Issues paper
AGL
Alinta
Australian Pipeline Industry Association
Australian Stock Exchange
Business Council of Australia Submission
Consumer Law Centre Victoria
Delta Electricity
Electricity Transmission Network Owners Forum
Energy Intensive Industries Alliance
Energy Networks Association
Energy Response Pty Ltd
Energy Retailers Association of Australia
Energy Supply Association of Australia
Energy Supply Association of Australia – Transmission Supplementary
Energy Users Association of Australia
EnergyAustralia
Enertrade
Ergon Energy - distribution business
Ergon Energy – retail business
Firecone Report to DOI Victoria
Firecone Supplementary
Freehills
Gallaugher Associates Pty Ltd
Geodynamics Limited
InterGen (Australia)
International Power Australia
LYA, AGL, TRU Energy and International Power
Macquarie Generation
Major Energy Users Group
National Electricity Market Management Company
National Generators Forum
Office of Energy, Western Australia
Origin Energy
Powerlink
Powerlink Supplementary
Public Interest Advocacy Centre
Public Interest Advocacy Centre Supplementary
Queensland Resources Council
Snowyhydro
Stanwell Corporation
Tasmanian Government
The Australian Competition and Consumer Commission and Australian Energy Regulator
Total Environment Centre
Trade Practices Committee of the Business Law Section of the Law Council of Australia
TransGrid
Transgrid Supplementary
TRUenergy
VenCorp
Verve Energy
Westpac

Discussion paper
AGL
Australian Petroleum Production and Exploration Association
Australian Pipeline Industries Association
Australian Stock Exchange
Coalition of Consumer Groups
Country Energy
Delta Electricity
Electricity Transmission Network Owners Forum
EnergyAustralia
Energy Action Group
Energy Intensive Industries Alliance
Energy Response
Energy Retailers Association of Australia
Energy Supply Association of Australia
Energy Users Association of Australia
Eraring
Essential Services Commission of SA
Flinders Power
Integral Energy
International Power
Macquarie Generation
Major Energy Users Group
National Electricity Market Management Company
National Generators Forum
Origin Energy
Powerdirect
Powerlink
Queensland Government
Renewable Energy Generators Association
Retail Energy Market Company
Expert advice commissioned by ERIG

ERIG commissioned a number of consultants to advise it on the matters under consideration. A list of the consultants engaged and the reports received is detailed below. Final reports are available at www.erig.gov.au.


**Planning and Governance Arrangements for the National Transmission Grid**, Firecone Ventures Pty Ltd, December 2006

**A report to ERIG on Transmission in the National Electricity Market**, CRA International, December 2006

**NEMMCO: Governance Arrangements**, Firecone Ventures Pty Ltd, December 2006

**The Gas Markets in Australia: Impediments to Efficient Development**, KPMG December 2006

**Impediments to Investment in Australia’s Energy Market: The Views of Investors**, KPMG, December 2006


**The Effectiveness of the Trade Practices Act to Guide Mergers in the Australian Electricity Market**, Acacia CRE Pty Ltd, December 2006
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