7 August 2009

Australian Energy Market Commission
AEMC Submissions
PO Box A2449
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ENA – Response to 2nd Interim Report, June 2009 – Reference EMO 0001

The Energy Networks Association (ENA) welcomes the opportunity to respond to the Australian Energy Market Commission (AEMC) 2nd Interim Report – Review of Energy Market Frameworks in light of Climate Change Policies released on 30 June 2009.

Energy network businesses deliver electricity and gas to over 13 million customer connections across Australia through approximately 800,000 kilometres of electricity distribution lines. There are also 76,000 kilometres of gas distribution pipelines. These distribution networks are valued at more than $52 billion and each year energy network businesses undertake investment of more than $5 billion in distribution network operation, reinforcement, expansions and greenfields extensions. Electricity transmission network owners operate over 57,000 km of high voltage transmission lines, with a value of $15 billion and undertake $1.6 billion in investment each year.

Note that electricity transmission businesses who are members of ENA have made a submission to the AEMC review through Grid Australia. Electricity transmission matters are dealt with through that submission.

ENA strongly considers that the efficient operation of the energy market framework is contingent on having regulatory settings which ensure full cost recovery, allow for pass-through of climate change related price signals to customers and has the capacity to address the risks posed by the incorporation of large numbers of embedded generators into distribution networks.

The ENA supports the AEMC view that the energy market framework must promote and support healthy markets that deliver efficient prices and services to energy customers. The Interim Report recognises that if prices are too low - restrained below costs - the participant is squeezed and may exit the market which is not a desirable outcome.

The AER and the AEMC have provided no positive confirmation that distributors are able to pass-through CPRS costs. The ENA notes that AEMC is proposing flexible mechanisms for retailer cost recovery and is silent on the issue for distributors. For gas distribution service providers there is the issue of existing long term gas contracts which only allow pass-though of a tax event. For electricity distribution, the concern is the need to reopen a 5 year price reset due to an unforeseen CPRS outcomes leading to a reassessment of all aspects of the price agreement. A regulation allowing for automatic price adjustments reflecting fluctuations in carbon related costs would remove uncertainty and potentially costly delays in enabling permitting cost pass through.

On the issue of incentives, AEMC acknowledges there may be a need to provide temporary innovation funding and cites the example of Ofgem in the UK which operates the Innovation Funding Investment (IFI) scheme. ENA supports this approach and would welcome the opportunity to work with the AEMC in developing such a scheme, ahead of the final report.

The crucial issue for the distribution sector is the development and implementation of smart networks (smart grids) which will drive a shift away from the traditional centrally focused 'generation-transmission-distribution" paradigm to a more customer driven interactive and distributed energy resource model.

Smart networks will enable real time interactions between all elements of an energy market from generator to end user. The outcome will facilitate rapid responses to price signals, energy supply fluctuations and demand shifts and facilitate the use of renewable energy and allow the two way flow of energy that is to accommodate energy generated by customers to flow back into the system.

Overseas experience clearly shows that distribution network service providers will play a crucial role in the way energy is produced and consumed in a carbon constrained economy.

The renewal of ageing energy networks with intelligent systems and smart metering technologies to improve customer service and operational efficiency and address climate change imperatives are critical to the future.

The challenge is to ensure that the current regulatory regime is not an impediment to the adoption of new technology but facilitates the implementation of smart networks. For this to occur, the framework establishing the implementation and operation of a national smart network infrastructure must be understood.

ENA believes that until the framework is in place it will be unclear as to how the regulatory regime will need to be altered. Greater analysis needs to be done and we encourage the AEMC to be open to this. ENA considers an appropriate way forward would be the establishment of an industry-government working group to set out the parameters of a national smart network including the technical components, and the requirement to ring fence between the regulated and unregulated components of the network. Only when this has been established can there be an assessment of how the National Electricity Rules need to be adjusted to accommodate the step change to smart networks.

ENA looks forward to further consultation with the AEMC on the energy networks related matters raised in this letter/submission in the near future. In the mean time please contact me should you wish to discuss our response further.

Yours sincerely

Andrew Blyth
Chief Executive

AEMC REVIEW OF ENERGY MARKETS FRAMEWORKS IN THE LIGHT OF CLIMATE CHANGE POLICIES

2nd Interim Report

7 August 2009

ENA Submission

Key messages

ENA supports the AEMC's proposal to ensure connection of new remote renewable generation is efficient and timely as the current process of bilateral negotiation may prove difficult to coordinate a large volume of network connections efficiently and quickly.

ENA welcomes the opportunity to be involved in the development of any charging arrangements in this area due to the possible impacts on the distributors and their TUOS payments/allocations.

Efficient operation of the energy market framework is contingent on regulatory settings which ensure full cost recovery, and allow for pass-through of climate change related price signals to customers.

AER and AEMC have provided no positive confirmation that distributors are able to pass-through CPRS costs.

Regulation allowing for automatic price adjustments reflecting fluctuations in carbon related costs would remove uncertainty and potentially costly delays in enabling permitting cost pass through.

ENA supports the introduction of formal arrangements designed to allow distribution businesses to recover the costs of accredited innovation projects.

Introduction

ENA makes this submission in response to the Australian Energy Market Commission (AEMC) 2^{nd} Interim Report – Review of Energy Market Frameworks in light of Climate Change Policies released on 30 June 2009.

ENA has focused its submission on a number of areas put forward by the AEMC in its Report that have direct relevance to energy networks. These areas include: connecting remote generation, regulated retail pricing, convergence of electricity and gas markets,

ENA's submission addresses the following chapters:

ENA Response

Chapter 2: Connecting remote generation

This chapter provides AEMC draft findings and recommendations on connecting new remote generation to energy networks (see Section 2.3.2 for outline of preferred option). The recommendation proposes the introduction of a new framework in the Rules for the planning, pricing and funding of transmission (or distribution) investment to create connection "hubs" in specific remote areas where there is demand for new generation connections as a result of the expanded RET.

The draft AEMC recommendation seeks to ensure that extensions to the network are sized efficiently for future generation such that customers can benefit from potentially significant total cost savings. Customers would, however, have some limited exposure to costs if the forecast generation does not materialise. The recommendation reflects a conclusion that the existing bilateral negotiation framework for connections is unlikely to support co-ordinated, efficiently-sized investment.

The AEMC considers that the existing framework based on bilateral negotiation will make it difficult for network businesses to co-ordinate network connections. Stranded asset risk is also cited as an impediment to sufficient timely investment in network connections

Questions

2a Will the recommended model adequately address the deficiencies in the existing framework?

2b Does the recommended assessment process appropriately balance customer risk with potential customer benefits?

2c Is there merit in allowing rival service providers to deliver network extensions for remote generation?

ENA Response

ENA supports the objective behind the AEMC's proposal to ensure connection of new remote renewable generation is efficient and timely as the current process of bilateral negotiation may prove difficult to coordinate a large volume of network connections efficiently and quickly. For example, to improve efficiency for large volumes of generator connections (eg micro/mini embedded generation on customer's roof) the ENA supports a standardised approach to connection applications using industry standard technical and commercial agreements. However, the ENA does not advocate the removal of bilateral negotiations (which currently work well for some large connections) under Chapter 5 of the Rules.

The Commission is proposing that network service providers (NSPs) identify and specify in detail possible remote connection line locations, capacities and indicative costs based on forecasts of future generation. NSPs would be required to publish such connection information in their Annual Planning Reports (APRs) in advance of receiving connection applications.

ENA has a number of serious concerns with this proposal. Firstly, a number of distribution networks are primarily urban and as such the ENA queries the application of 'remote connection' and whether all NSPs will be required to meet the proposed regulatory obligation by positively identifying opportunities and specific design options for remote connection assets. ENA seeks a clear definition of 'remote generation' by the AEMC particularly given the geographical spread of its members. ENA supports the comments raised by the AER and NGF in response to the 1st Interim Report that there is the real possibility that by requiring NSPs to identify remote connection assets that it may create incentives to inefficiently "oversize" the network in anticipation or possible, but unlikely, level of new connection activity.

Secondly, there are concerns that DNSPs will take on greater liability risks as a result of the inability to accurately predict and identify potential generation connection sites, which potential generators will rely on to make informed location decisions. In addition, NSPs would be required to publish a standard contract together with prices to allow interested parties to scrutinise the analysis of forecast generation connections proposed. Once again, ENA is concerned that such information will need to be extremely accurate to allow interested parties to rely on with a degree of certainty and there will be an onerous obligation placed on NSPs to ensure that the published contract and prices remain accurate and relevant as the generation forecast changes to reduce the chance of reliance on inaccurate data. ENA seeks further clarification of the role of both AEMO and NSPs in this crucial area so as to avoid any potential liability claims.

ENA supports the comments raised by Grid Australia in its response to the 1st Interim Report in that NSPs should be allowed to adopt an 'open season' approach in their APRs, complemented with bilateral negotiations for new connections. This would allow the process for connection applications to be streamlined and improve the efficiency of network planning. In order to implement this approach, the Rules would need to provide for an appropriate length of the open season 'window' and the frequency with which the process could be repeated. Following the closure of each application window, the NSP would then complete the connection application process for all applicants in accordance with the existing process set out in Chapter 5 of the Rules.

Electricity transmission businesses have provided specific comments through the Grid Australia submission. ENA supports the points raised by Grid Australia.

Chapter 3: Efficient utilisation and provision of the network

This chapter discusses AEMC draft findings and recommendations on the efficient use and provision of the network. The AEMC draft recommendation proposes the introduction of a form of generator charge for all generators (G-TUOS). AEMC also seek views on whether there is a need for a complementary short term congestion pricing mechanism, focusing in particular on a mechanism for localised and time-limited intervention for selective application to address acute, short term areas of congestion. The proposals seek to ensure that congestion costs are signalled more explicitly to generators as a means of promoting more efficient decisions. The recommendations reflect a finding that there is a high likelihood of congestion, and its associated economic costs, increasing as a result of the expanded RET and, to a lesser extent, CPRS. AEMC have found that framework changes in this area, with particular focus on the incentives on generators, are likely to promote more efficient outcomes in the presence of congestion.

Questions

3a Do you agree that we have accurately identified which elements of the existing framework are considered inadequate and therefore require change?

3b Would the G-TUOS charging option design improve pricing signals to promote efficient location and retirement decisions in the most efficient way? Are there any design variations that may improve the signals?

3c Given that G-TUOS is a preferred option, what additional value would a congestion pricing mechanism add? If such a mechanism is required, what design variations should be considered to improve signals to manage short term intra-regional congestion in the most efficient way?

ENA Response

The interim report states that the AEMC has not reached a firm view on the exact design of the G-TUOS charge.

The ENA welcomes the opportunity to be involved in the development of any charging arrangements in this area due to the possible impacts on the distributors and their TUOS payments/allocations. We are keen to understand the impacts on the distributors before any design is finalised.

Victoria is currently proposing the use of a G factor in TUOS for recovery of the Government's premium feed in tariff legislation. Given there will be a number of variations in the TUOS arrangements in the future, combined with a move to more cost reflective network tariffs as a consequence of AMI, this may have the potential to impact the distributors network tariffs and balancing constraints.

Electricity transmission businesses have provided specific comments through the Grid Australia submission. ENA supports the points raised by Grid Australia.

Chapter 4: Inter-regional transmission charging

This chapter discusses AEMC draft findings and recommendations on inter-regional transmission charging. The AEMC draft recommendation proposes the introduction of an obligation on transmission businesses to levy a "load export charge" on the transmission business in each adjacent region. This charge would reflect the costs of providing transmission capacity to transport flows to the adjacent region.

The proposal seeks to improve the overall cost-reflectivity of transmission charges, and remove existing implicit cross-subsidies between customers in different regions. The recommendation reflects a finding that transmission investment to support flows between and across NEM regions is likely to increase in significance as a result of market responses to the CPRS and expanded RET.

Questions

4a **Is the proposed design for the load export charge appropriate as an effective mechanism to address the identified problems?**

4b **Is our suggested commencement date of 1 July 2011 achievable?**

ENA Response

There is not a clear understanding of how inter-regional transmission charging will work and how these charges will ultimately be recovered from or refunded to end users. If these costs (or refunds) are passed to the DBs to be collected from (or paid to) end users (as is the current situation for the recovery of transmission costs) then such scheme might have a negative/neutral or positive impact on the DB depending on the annual variation in the magnitude and type of payment (collectable from or payable to end users). DBs are also concerned about possible tariff constraints.

The ENA would welcome an early indication of the inter-regional charging and distributor cost sharing so that its members have an opportunity to incorporate this into annual network tariff submissions to the AER.

For a fuller response to this issue please refer to the Grid Australia submission.

Chapter 5: Regulated retail prices

This chapter discusses AEMC draft findings and recommendations in relation to the regulation of retail energy prices. The AEMC draft recommendation proposes that increased flexibility to adjust regulated tariffs should be introduced into the frameworks in those jurisdictions that retain retail price regulation.

The recommendation reflects AEMC finding that increased uncertainty and volatility of carbon inclusive wholesale energy costs will follow the commencement of the CPRS. The risks this may pose to the viability of retailers and to the development of competitive retail energy markets will be exacerbated if financial instruments to allow effective hedging of the costs are slow to emerge.

Questions

5a Do you agree that wholesale energy costs will be less certain, less able to be hedged and harder to forecast following the introduction of the CPRS?

5b If jurisdictions and/or pricing regulators incorporate additional flexibility in pricing instruments, as set out in the recommended principles, does this sufficiently decrease the risks to retail competition and of retailer failure?

5c Are existing regulatory approaches adequate to assess the cost to retailers of the expanded RET?

ENA Response

The ENA supports the AEMC view that the energy market framework must promote and support healthy markets that deliver efficient prices and services to energy customers. The Interim Report recognises that if prices are too low, that is restrained below costs the participant is squeezed and may exit the market which is not a desirable outcome.

The Interim report also notes that the increase in costs will be hard to forecast and initially difficult for retailers to manage. It is this difficulty of forecasting costs and the possible volatility of costs that leads the AEMC to recommend a more flexible pricing arrangement for retailers.

Gas and electricity distributors will also be faced with difficulty in forecasting costs and some volatility on their input costs:

- Forecasting future demand and demand side participation will become more difficult and be subject to more volatility
- Forecasting customers demand side response arising from smart metering and more cost reflective pricing
- Forecasting the input cost of goods arising from increases in costs on our suppliers created by the CPRS eg copper, concrete, gas pipe etc
- The impact of network losses and carbon credit costs for gas networks will be difficult to forecast
- The impact of more two way flow of electricity created by increasing levels of small scale embedded generation will alter the long standing fundamentals of planning and operating distribution networks.

The ENA has previously recommended to the AEMC that there needs to be flexibility and innovation in the regulatory framework for the cost imposts on the network businesses also.

The ENA is supportive of a robust ROLR framework and recognises that ROLR will be introduced in the second draft of the NECF submission. However it should be recognised that this is a high level framework and does not deal with the transactional level within the industry that will ensure a ROLR framework is workable.

The Victorian gas market has spent a considerable amount of time developing and implementing ROLR capability at a transactional level and there are still issues being raised across industry in relation to interpretations on the detail.

The ENA considers that reuse of the existing transactional capability across the industry would be a prudent course of action in the national framework.

Chapter 7: Investment in capacity to meet reliability standards

This Chapter discusses AEMC draft findings on the framework for long term reliability in the NEM. AEMC has found that the existing framework provides effective signals to promote efficient levels of investment in transmission capacity, generation capacity and demand response. It can, therefore, be expected to continue to operate in the long term interests of consumers, if those signals are appropriately maintained. This is likely to involve significant increases in the spot market price cap over time, in particular to ensure that the necessary peaking plant to complement intermittent wind-powered generation is economically viable.

The AEMC recognises a number of risks inherent in the current framework, including issues relating to the practical operation of the contract market, and note that some of these risks might be exacerbated by an increase in the range of possible price outcomes in the spot market. However, we are not persuaded that these risks are substantially altered by the implementation of the CPRS and expanded RET or that fundamental change to the existing frameworks are needed in order to manage them.

Questions

7a **Do you agree with our description and assessment of how the current framework operates and our finding that the framework for the medium to long term is resilient to the stresses created by the CPRS and expanded RET?**

7b **Do you agree with our characterisation of the risks under existing frameworks, and how could they be managed or mitigated?**

ENA Response

The AEMC has expressed the view that the contract market appears capable of signalling the need for different types of plant in response to the CPRS and expanded RET. According to the AEMC:

"If, as a result of wind penetration in a particular region, there is an increased demand for [back-up] capacity at peak, then this should be reflected in the expected value of cap contracts in that region. A forward curve in caps would reveal this quite clearly."

The AEMC appears to be speculating and has not relied upon a firm source or citation.

The AEMC appears to have also overlooked, without mention or consideration, the results of past reviews into the possibility of separate markets for generation capacity. For example, in 2002, the ACCC commissioned a study into financial contracts for capacity, which was undertaken by Farrier Swier Consulting[1]. The research was performed in the context of an investigation by NECA into capacity mechanisms. NECA examined options to reduce extreme volatility and related risks in the spot market with the objective of providing a longer-term and smoothed approach for price signals for new investment in generation.

Admittedly, in concluding its review, NECA recommended no change to the energy-only structure of the NEM. However, the AEMC appears to have overlooked some of the substantive arguments which were raised at the time. These arguments should perhaps be revisited, particularly given the time lapse since the NECA review was conducted.

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[1] Analysis of Electricity Capacity Market. A report prepared for the Australian Competition and Consumer Commission, 4 April 2002. Prepared by Farrier Swier Consulting and Barker, Dunn and Rossi Inc.

The energy only structure of the wholesale market has, to date, provided appropriate signals for investment in new generation capacity. According to Firecone, consultants to the AEMC, the capacity of new fossil-fuel powered generation installed in Australia over the past ten years is approximately equal to 14,700 MW, with a share of this capacity currently under construction. The AEMC has pro-rated this figure down to 11,000MW for the NEM. While the existing market frameworks have undoubtedly delivered new investment, the AEMC has correctly raised a question about whether "what appears to have operated satisfactorily in the past will continue to do so in the future". In particular, there are some doubts about whether existing market frameworks will enable the provision of new generation capacity in a timely fashion.

An important issue in stimulating new investment is the level of the spot market price cap. The ENA acknowledges that the maximum offer price will increase to $12,500 per MWh on 1st July 2010 as a result of a final determination and rule change made by the AEMC in May 2009. The regulated maximum offer price will need to be reviewed on a regular basis so as to ensure settings are right.

The AEMC appears to have accepted – as an article of faith – that the energy only structure of the wholesale market is the only appropriate form of arrangement, whereas other types of market structure, such as capacity obligation markets, have been shown to operate satisfactorily in other jurisdictions. These alternatives, which include financial contracts for capacity, may be worthy of consideration (and review) because they offer the prospect of less volatile (and therefore less unpalatable) spot prices during periods of a tight supply and demand balance in the NEM.

In Victoria, network support and control services (NSCS) are used to manage electricity demand during periods of tight reserve margins or generation capacity shortfalls. By way of example, United Energy Distribution (UED), bids into the voluntary market through a demand side aggregator, with offers to reduce the load on the network, on a contingent basis, by around 30MW. If called upon, UED will then reduce the voltage on the network by between 2% and 5%, thus helping to bring down the resistive load (with no material impact on non-linear load). The arrangements thus described are designed to moderate the overall load on the distribution system. UED expects that there may be a continuation of these practices into the future as a means of coping with generation reserve inadequacies.

The ENA also confirms the point, already acknowledged by the AEMC, that greater penetration of gas-fired generation will result in an increase in utilisation of existing gas networks (both distribution and transmission). A rise in embedded gas-fired generation may mean that the distribution system is operated at higher pressures for longer periods of time, resulting in increased system losses through unaccounted for gas (UAFG). Over the summer period, Multinet Gas for example, typically lowers the operating pressure across the gas network, so as to attenuate losses through UAFG; however, this practice is expected to change with the growth in embedded generation.

Chapter 8: Convergence of gas and electricity markets

This chapter discusses AEMC draft findings relating to the issue of convergence of gas and electricity markets. The AEMC has found that the existing energy market frameworks are sufficiently robust to manage the greater interactions that may arise between the electricity and gas markets following the introduction of the CPRS and expanded RET. We note that the existence of a single rule maker, the AEMC, and a common system operator, the AEMO, will assist requirements for co-ordination between the two markets (i.e. market settings (such as price caps) and market intervention by system operator).

Questions

8a **How should reviews of market settings (such as market price caps) be best aligned across the gas and electricity markets?**

8b **Do you agree that the current energy market frameworks would allow for AEMO to effectively review the existing rules provisions relating to market interventions?**

ENA Response

The ENA is supportive of the AEMC requesting the reliability panel to consult with AEMO on its current review of reliability settings. The Reliability papers issued recently for consultation focus mainly on the electricity market with little consideration of the increasing use of gas fired generation and its potential impact on the gas market when system security is threatened. The ENA note AEMO's role in gas and electricity market issues.

The paper focuses on the most valuable use of the fuel or on the cost caused by the instruction in the related market. Consideration should also be given to not just cost but the short term (gain) and longer term customer impacts the instructions create.. AEMC could also provide some parameters so that infrastructure is protected ie that whilst electricity is an essential fuel, gas will not be used for electricity generation at the expense of security of the gas distribution network and longer term outages in a non essential fuel.

Far greater emphasis should be placed on deployment of improved customer engagement for demand side response, other demand side initiatives, use of alternate generation etc at times of high electricity demand or at times when gas is needed for gas network system security.

Chapter 9: System operation with intermittent generation

This chapter discusses our draft findings on power system operation with increased intermittent generation. We have found that the existing energy market frameworks are sufficiently robust to enable the system operator to maintain a secure system following the anticipated large increases in renewable generation as a result of the CPRS and expanded RET.

The current frameworks for managing the power system provide a sound foundation, and already embody a number of reforms to manage the implications of larger volumes of intermittent generation connected to the network. We also consider the framework to support further review and reform to be capable of sustaining timely and efficient further operational change. We note that the AEMO and the AEMC Reliability Panel are undertaking reviews to inform the long term arrangements for effective management of voltage control.

Questions

9a Is it necessary to create formalised centrally coordinated contracting arrangements for the provision of power system inertia? If so, what is the nature of the process by which those arrangements should be developed?

9b Is there adequate transparency in the process by which FCAS recruitment and interconnector capability is affected by the increasing penetration of intermittent generation?

ENA Response

The ENA considers that formalised, centrally coordinated contracting arrangements for the procurement of inertia may be required, resulting, potentially, in a greater role for AEMO. As the AEMC has noted, much of the inertia currently supplied within the power system is, in fact, a legacy of past arrangements associated with the construction and commissioning of large generators, which occurred prior to the commencement of the NEM.

Solar energy sources provide no inertia while wind-powered generators contribute comparatively little inertia per MW of installed generation capacity. In view of the prospective shift towards wind generation, a much higher level of generation capacity will be needed to achieve the same inertia properties as are currently achieved using the available, installed coal-fired plant. A rough estimate is that 800MW of wind generation is required to produce the same inertia as is currently offered by 500MW of coal-fired generation.

The emergence of large numbers of small intermittent generation sources should continue to be monitored by the AEMC. Should the market develop in such a way that large numbers of small unscheduled generation connect to distribution networks causing congestion issues, there will be a need to review the existing frameworks to ensure the continuation of effective and secure system operation.

A further possible impact of the CPRS and expanded RET is for large numbers of unscheduled generation to seek to connect to distribution networks. This has the potential to cause significant congestion issues and require more active management. This development should be monitored to identify whether changes to the existing framework, including scheduling thresholds, need to be made to ensure effective and secure system operation.

Chapter 10: Distribution networks

This chapter discusses AEMC draft findings on the frameworks for managing distribution networks with larger volumes of connected generation and more variable network flows. The AEMC has found that the existing energy market frameworks are sufficiently robust to support consequent changes in the operations (and costs) of distribution businesses. The AEMC recognises, however, that there is likely to be a period of substantial change for distribution networks in response to the CPRS and expanded RET. The AEMC is seeking views on a potential refinement to the existing framework to provide temporary funding to support innovation by distribution businesses, in a transparent and accountable manner, to manage these changes efficiently.

Questions

10a **Do you agree that the energy framework for distribution is able to manage the challenges imposed by the CPRS and expanded RET?**

10b **Is there merit in introducing formal, but temporary, arrangements to allow distribution businesses to recover the costs of accredited innovation projects?**

ENA Response

As much of Australia's existing $60 billion energy infrastructure was built in the 1950s to 1970s, with an asset life of around 40 years, there is a national trend to upgrade the nation's network over the next decade. This presents an opportunity to take advantage of new technologies and 'future-proof' the network, not only to meet the continuing growth in peak electricity consumption, but also to cope with a fundamental change in the delivery of electricity services in a carbon constrained environment.

One of the main limitations of the existing electricity production and delivery processes is that consumers are passive participants, with limited accessible information to demonstrate energy usage and costs, little or no choice about energy source and only receiving a bill weeks after using the electricity. In addition, the current design of the network is for a one-way flow of both energy and information, and as such it will not meet the anticipated expectations of consumers and key stakeholders in the future, that require two-way energy and information exchange.

While this future is dependent on the uptake of new technology, the greater dependence is on the need for consumers to fundamentally change the way that energy is used. A main objective of the smart network is to enable consumer choice, and as increasing awareness of climate change and the financial impacts of rising electricity prices take effect, consumers are beginning to show a willingness to become participants in the energy market and to make choices about their energy use.

The means by which the sector will deliver a smart network is to add an 'intelligence' layer to the core transmission and distribution systems. This intelligence will enable secure, reliable and cost effective two-way energy and information flows to and from consumers and devices on the network, and will be supported by enabling solutions.

The result will be a transformation from a process characterised by dominant large-scale generation, with little or no customer involvement or choice, and with limited information about and control over the devices by which the infrastructure delivering the energy is managed, to one which enables and facilitates higher levels of local, renewable energy generation, customer choice and participation, real-time management and operation of the network infrastructure.

The Federal and State governments have introduced a range of policy initiatives to reduce emissions of carbon and other gases into the atmosphere and have moved to encourage greater uptake of renewable energy, promote energy efficiency and invest in technologies that reduce reliance on traditional CO_2 emitting energy sources.

As a result of these measures, there will be significant changes to how Australians produce and consume energy in the near to medium term. The energy network sector will play an important role in facilitating the shift to a low carbon economy and will meet these energy challenges through the development and implementation of the smart network.

The key means by which demand and emissions can be reduced is by:

- Providing consumers with information about the amount and cost of the energy they are using and enabling them to make choices before they buy.

- Facilitating local, renewable generation.

- Providing better ability to deal with the intermittency of large-scale renewable generation such as wind, wave and solar.

- Facilitating the uptake of electric and hybrid vehicles. These vehicles will be a new demand on the system, but will also act as a source of energy storage. The key drivers for change are the need to respond to climate change through the reduction of carbon emissions, and the need to maintain and enhance energy security. The involvement of energy users is critical in responding to both drivers.

In the short term, a smart network will function more efficiently, enable the delivery of the level of service that consumers have come to expect more affordably in an era of rising costs, and offer considerable public benefits such as reducing green house gas emissions. In the long term, a smart network will facilitate a step change in the way energy is produced and consumed.

The AEMC has recognised that increased variability of flows on the network may shift the focus of distribution businesses from simply reacting to demand growth to requiring more active management of the network. Existing distribution systems have been planned and developed having regard to the traditional flow of electricity from upstream generation sources to end-use customers. However, a significant increase in the number of generating units connected directly to the distribution network will impact on the unpredictability of network flows, and consequently the difficulty of meeting network performance requirements. As a result, the AEMC notes, network management may be increasingly geared towards system operation requirements and efficiently connecting generation. The AEMC has conceded that achieving a change in focus may impose new costs onto distribution businesses.

The prevalence of micro-generation will add greatly to the complexity of electricity distribution networks. Firstly, redundancy will need to be incorporated into the design so that the distribution system can function as effectively when micro-generators are inactive as when they are in operation. Secondly, highly robust mechanisms will need to be developed in order to ensure the safety of connections to embedded generators in different operating conditions. The “fail-safe” mechanisms will have to cope with alternative states of the network and with varying levels of output from the installed, distributed generation capacity. The potential safety risks will be heightened as micro-generation becomes more prevalent. Smart devices will need to be designed and built so as to assist in the task of diagnosing and identifying faults. The devices will provide a means for conveying information about operating status between network operators and generators, and will also enable safe access to the network for distribution network personnel.

Traditional, manual methods of locating faults will no longer be satisfactory from the perspective if either safety or efficiency.

The engineering challenges to be addressed, and the need for further infrastructure, will give rise to a marked increase in the costs incurred in building and maintaining distribution networks. Already, the connection of distributed generation poses considerable challenges for the engineers and planners in the distribution businesses. Experience to date has shown that extensive analysis and consultation is required to overcome technical hurdles. The immature stage of development of the industry supporting embedded generation is another shortcoming because proposals for new micro-power plants are often bereft of a detailed engineering consideration of the broader ramifications for the network. The net result is delays in processing applications, and added costs for distribution businesses.

In respect of cost recovery, the existing regulatory framework may prove to be inadequate and inflexible because of the five-yearly cycle of regulatory reviews and the long lead times involved in educating and appraising regulators of the changed infrastructure requirements. The ENA therefore firmly believes that more flexible cost-pass through mechanisms should be put in place.

To optimise investment in emerging smart network technologies, there are three areas in which the regulatory framework needs to be examined:

- facilitating research and development expenditure (discussed below)
- ensuring the full value of investments in such technologies, for example reductions in carbon emissions and avoided expenditure in generation plant and input costs are captured, and
- in order to gain the maximum benefit from the investment of smart network infrastructure and technologies, it is essential that cost reflective pricing to consumers is implemented.

A challenge to smart network implementations across Australia is that the current 'ex-ante' regulatory framework does not adequately accommodate change and the adoption of new technologies in a timely fashion. The regulatory framework needs to be modified in a way that supports the implementation of smart network solutions across five-year regulatory periods.

It is in the interests of the network industry—and ultimately the national interest—that policies should be amended to encourage businesses to optimise their investment in this area. Any investment to stimulate the initial development of smart networks should be directed towards funding the areas that to date are not enabled as part of the current regulatory framework. For example, areas that involve multiple industry participants such as electric vehicle development. It would be disappointing if this investment was directed solely at smart metering projects and not focused on developing smart networks across the entire transmission and distribution business supply chain. Similarly, it would be disappointing if funding was distributed to a range of projects, each of which does not have the level of scale to provide 'learnings' that would be required to provide real input to formulating policy.

The industry will benefit from the recently announced Energy Efficiency Initiative (EEI) proposed by the Federal Government. The EEI is an opportunity to consider issues that span the entire electricity industry and the $100 million investment has the potential to define a critical national competence.

Research and Development

The need for Research and Development (R&D) expenditure arises for a number of reasons, including—but not limited to—the currently unknown impacts of exponential increases in the volume of micro-generation connections; using renewable (and therefore intermittent) sources and the corresponding impact on the operation of the network; the quality of the energy delivered to customers; and the need to develop real-time pricing signals (tariffs) which interface with home energy management systems.

Consideration must be given to R&D funding for smart networks to ensure that in the absence of regulatory policy being changed, that sufficient investment is being made to maintain national skills and innovation in this area. This is extremely important to accelerate the changes required for smart networks; to support the timeframes for changes in the industry; and to build national competencies in this field.

Under the current regulatory environment in Australia, there is a clear disincentive for a distribution business to engage in activities of a developmental nature that may have the potential of reducing longer-term operating capital costs.

It is proposed that Australia consider adopting an incentives scheme that would direct investment towards broad-based smart network initiatives, related to demand management; asset management; communications improvement; and other more general areas of improved products and network management designed to deliver customer benefits.

It is important that sponsorship of R&D investment in smart network technologies allows enough opportunity for proper investigation and to demonstrate clearly the customer interaction models on a scale large enough to represent the national build-out.

Such a proposed arrangement is not untested. The public benefit that can be achieved through technological and process innovations has been a matter of recent debate in the United Kingdom (UK). It has been clearly demonstrated in the UK that investment in R&D activities all but ceased with the introduction of incentive regulation. To address this concern and to provide the basis for future efficiencies, the UK energy regulator, Ofgem, has initiated a new scheme that provides significant allowances to network related innovations by use of an innovation funding incentive (an 'I factor'). Examples of the myriad of types of projects contemplated by this scheme were first outlined in a 2004 Ofgem report.

Since introducing the scheme, innovation investment by infrastructure businesses has increased rapidly, demonstrating the significant scope for researching better and more cost effective ways to delivering infrastructure services.

The ENA supports the introduction of formal arrangements designed to allow distribution businesses to recover the costs of accredited innovation projects. The regulatory framework may pose actual and perceived barriers to innovation, as acknowledged recently by an Ofgem team conducting a review into the workings of the current approach to regulating energy networks in Great Britain. In a position paper[2] on innovation prepared for the RPI-X@20 review, reference was made to the following hurdles identified by UK electricity distribution network operators:

- The perceived lack of clarity over the way that any profits, and losses, resulting from innovation will be treated in the regulatory regime.
- An absence of competition, which effectively removes the need for the network companies to 'compete' so as to retain market share.
- The five-year price control periods, which give networks a short-term focus and reduce incentives to progress innovative projects, because the benefits may not materialise over the short term. This is in conflict with climate change mitigation objectives which are long term.
- The low risk nature of the energy networks, which has been shaped by the regulatory regime and makes the companies averse to engagement in more risky innovation.
- The risks associated with potential deviations from minimum standards with which the networks must comply; and
- The loose definition of network outputs and the differential incentives for operating expenditure and capital spending, which potentially reduces incentives to ensure efficiency in capital outlays.

The position paper acknowledges that research and development expenditure by distribution network operators has been on a declining trend since 1989-90. The paper proposes, and then examines, on a *prima facie* basis, various models for innovation funding.

The AEMC report must identify energy transmission and distribution networks in supply-side deliberation and it must emphasise that transmission and distribution networks should, and if given the right incentives, will play a significant role in the development of supply-side responses.

This will mean having the incentives in place to allow new ways of delivering energy to customers through the development of smart networks (smart grids), undertaking R&D, developing demonstration projects for energy efficient use of energy and adopting innovative technologies. It is now accepted that world leaders in energy networks are those who innovate, who implement smart grids; and who drive high technology solutions.

The energy industry is now at a point of change where new and significant challenges face the industry. These include responding to climate change and the global economic downturn, while remaining internationally competitive and raising living standards.

[2] Regulating energy networks for the future: RPI-X@20. Innovation in energy networks: Is more needed and how can this be stimulated ? Prepared by RPI-X@20 and Regulatory Finance, Ofgem (Office of gas and electricity markets), U.K.

ENA notes that AEMC has ignored our transition concerns about cost pass through related to the CPRS. For gas distribution service providers there is the issue of existing long term gas contracts which only allow pass-though of a tax event. For electricity distribution, the concern is the need to reopen a 5 year price reset due to an unforeseen CPRS outcomes leading to a reassessment of all aspects of the price agreement. A regulation allowing for automatic price adjustments reflecting fluctuations in carbon related costs would remove uncertainty and potentially costly delays in enabling permitting cost pass through.

AEMC acknowledges there may be a need to provide temporary innovation funding and cites the example of Ofgem in the UK which operates the Innovation Funding Investment (IFI) scheme. ENA supports this approach and would welcome the opportunity to assist in developing the scheme, ahead of the final report. Attached is a brief summary of innovation funding applied to overseas distribution networks in the United Kingdom.

Attachment A

INNOVATION INVESTMENT FUNDING APPLIED TO OVERSEAS DISTRIBUTION NETWORKS (UK)

The Innovation Funding Investment (IFI) was started by the UK Government energy regulator, Office of Gas and Electricity Markets (Ofgem) in October 2004 in recognition that the risk reward balance of research, development and innovation differed for that applying to normal distribution businesses (DBs).

The IFI was introduced as part of the electricity distribution price control for 2005-2010. It represents Ofgem's response to the consistent decline (actually approaching zero spend) in investment in research and development by DBs since 1990. It allows a DB to pass through to customers 80% (tapered from 90% to 70% from 2005 to 2010) of the cost of eligible IFI projects. In February of 2006, after a period of consultation, Ofgem agreed to extend the IFI scheme to the end of the next price control period to give the DBs the confidence to build their R&D portfolios.

Eligible IFI projects are defined as being designed to enhance the technical development of distribution networks and can embrace asset management from design through to construction, commissioning, operation, maintenance and decommissioning. Ofgem is currently reviewing the scope of IFI projects with the DBs with the intention of embracing projects related to environmental issues.

From October 2004 to the end of Financial Year 2007-08 around £29 million has been invested by DBs in IFI projects. Examples of IFI funded projects include:

Superconducting fault current limiter;; Online condition monitoring cables, lines and switches; Fault level monitor; Headspace Gas Testing on oil switchgear; Underground cable plough; Broadband power line carrier; Alternative fluid transformer; Line tracker and line sensor; Wood pole disposal; LV fault program; LV automation; LV regulator; Fenix customer interface module; Voltage optimiser for wind farms; Intelligent universal transformer; Network sensors (Smart dust); Radiometric Arc fault location; Vegetation management project; Wind turbine effects-transmission lines; Cable fault sniffer; Improved specification of cable jointing resin; New conductor for overhead lines; Surge Arrestors; and Economic charging method for electricity distribution networks.

Project Outcomes

The following list provides brief comment on the deployment and use of past project outputs:

Cable fault sniffer - successfully deployed across DB resulting in faster and more efficient fault location.

Remote updating of switching schedules by mobile communications – this real time communication link between Field staff and DBs GE Enmac SCADA system has been rolled.

Improved specification of cable jointing resin - improved adhesion performance. Adopted in DBs specification.

"Head Space Gas Testing" on oil switchgear – DB originally deployed this technology to provide non-invasive check for onset on oil sludging on a population of over 2,000 units of oil filled distribution switchgear. The same tests have been repeated on sample basis as part of risk management. Current research aims to extend the capability to determine need to maintain switchgear.

Lightning protection - output used to re-write the national document ACE Report 55. WPD lightning protection policy embraces outputs.

New Conductors for Overhead Lines - This project involved significant input from DB. Report covered the use of the gap-type conductor technology which has just been deployed by DB on the 132kV Ernesettle - Prince Rock B-Route refurbishment. The use of this new conductor avoided undergrounding and, coupled with the use of Balfour Beatty Utility Solutions Catenary Support System (CSS), used in its erection, saved in excess of £3M + cost of easements over some 5km of route over the alternative undergrounding option. The CSS was not IFI funded, and avoided extensive use of scaffolding. It is estimated that the saving attributable to the use of gap conductor was in excess of £2.5M.

Alternatives to Wood Poles for Overhead Lines - The completion of this project conveniently coincided with the recent review of the European Biocides Directive which suggested the possible banning of creosote as a preservative. This work informed DB comments as to the impact of such a ban, and also confirmed that current policy was appropriate.

Grading Rings and Arc Gaps for Long Rod (132kV) Polymeric Insulators - Polymeric insulators have many advantages over ceramic (glass or porcelain) units, but have very different material properties which require particular attention. The output of this project confirmed certain design and application requirements which are reflected in DBs policy/specifications. 132kV applications of polymeric insulators include the B Route, currently being restrung with gap-type conductor. Incorporated into DBs specification.

Surge Arrestors - A project examining the principal failure modes of polymeric surge arrestors allowed the key design features of such units to be identified, which in turn has informed DBs specification. All 11kV and 33kV surge arrestors currently purchased by the DB are polymeric. Incorporated into DB specification.

Economic Charging Method for Electricity Distribution Networks completed - Ofgem consulted and approved and now in use.