Energy Supply Association of Australia www.esaa.com.au

ABN 98 052 416 083

Level 2
451 Little Bourke St
Melbourne

GPO Box 1823
Melbourne
Victoria 3001

P +61 3 **9670 0188**
F +61 3 **9670 1069**
E info@esaa.com.au

12 August 2009

Australian Energy Market Commission
AEMC Submissions
PO Box A2449
SYDNEY SOUTH NSW 1235

By email: submissions@aemc.gov.au

AEMC Review of Energy Market Frameworks in light of Climate Change Policies – Second Interim Report

The Energy Supply Association of Australia (esaa) welcomes the opportunity to comment on the Australian Energy Market Commission's (AEMC) Review of Energy Market Frameworks in light of Climate Change Policies – Second Interim Report (the Interim Report).

esaa is the peak industry body for the stationary energy sector in Australia and represents the policy positions of the Chief Executives of over 40 electricity and downstream natural gas businesses. These businesses own and operate some $120 billion in assets, employ over 40,000 people and contribute $14.5 billion directly to the nation's Gross Domestic Product.

esaa agrees with the AEMC that the Federal Government's proposed Carbon Pollution Reduction Scheme (CPRS) and expanded Renewable Energy Target (RET) represent significant challenges for the energy sector and the market frameworks going forward.

While esaa broadly supports the AEMC's identification of the material issues with the energy market frameworks, esaa notes that the Interim Report highlights a number of fundamental but still either undemonstrated or unresolved issues. These include congestion management, transmission policy and the ability of the current frameworks to deliver capacity.

esaa considers these issues, where they can be demonstrated to be significant, are unlikely to be adequately resolved via some of the piecemeal policy responses proposed in the Interim Report; particularly within the limited timeframe allocated to the current review.

For the National Electricity Market (NEM), esaa's primary concerns are with the proposed Generator Transmission Use of System charge and the standing reserve arrangements. esaa is concerned that these proposals are incremental solutions (which could actually have much wider unintended impacts on the market) to fundamental NEM design and operational issues and that more detailed consideration and analysis of the issues is required.

In the Western Australian context, esaa considers that the market frameworks are already exhibiting signs of stress which will be exacerbated by the introduction of the proposed CPRS and expanded RET. The AEMC's recommendations for the reform path are therefore broadly supported. Achieving full cost reflectivity in the retail market is of utmost importance and should be addressed as a matter of priority. Similarly, ensuring efficient and cost-reflective dispatch of generation is also critical to ensuring ongoing security of supply. Network access policy also needs to be analysed with a view to ensuring dynamically efficient and co-optimised generation and transmission investment.

esaa considers that without careful assessment, what may appear to be incremental changes to the current frameworks, particularly in the NEM, risk undermining a decade of progress toward energy market reform and the resulting efficiency gains. Any final recommendations for comprehensive and immediate reforms to the energy sector should be made cautiously and on the basis of careful cost-benefit analysis and industry consultation. Given the importance of some of the issues raised, esaa considers the AEMC should evaluate the scope to recommend further and separate reviews to adequately resolve any outstanding market design issues.

If you have any questions or require any further information, please contact Nicholas Wilson, Policy Development Manager, at nicholas.wilson@esaa.com.au or 03 9670 0188.

Yours sincerely

Brad Page
Chief Executive Officer

Efficient utilisation and provision of the network

The Interim Report states that congestion is likely to be material and persistent under the CPRS and expanded RET. Modelling undertaken for the AEMC indicates that in particular northern South Australia may experience more supply-driven congestion as a result of high wind penetration. The AEMC consider that given pockets of congestion are probable, especially in the short term, a mechanism is needed to provide an effective long-term and cost-reflective price signal to generators to inform both locational and retirement decisions.

esaa considers that due to the significant financial impact congestion and transmission failure can have on generators, as a general principle, where congestion risk is demonstrated to be a material and ongoing problem there should be a way of pricing and allocating that risk among existing and new generators, at the point where the congestion is material, to encourage efficient investment and production decisions. However, as ongoing debate and a sequence of past policy reviews have shown, there are a range of views among market participants, policy makers and regulators about the most effective policy frameworks and mechanisms to implement the pricing and allocation of risk.

While at the most basic level many would agree that the 'role of transmission' is the reliable delivery of least-cost generation in an efficient manner, there is no general consensus on fundamental issues such as electricity transmission pricing and access (who pays and what do they get in return) and congestion management on the shared network. Transmission policy raises seemingly intractable questions about whether some parties should be able to secure rights to transmission services at the expense of other parties, and if so, what are the implications for the competitive market and open access regimes.

esaa appreciates the AEMC have sought to consider the relative economic costs of congestion as a result of the CPRS/RET. However, esaa has concerns that the level of analysis undertaken to date has not been sufficient to justify the materiality of problem and to reach the conclusion to implement the specific solution proposed by the Commission.

esaa notes that the due diligence review by EGR Consulting of the two modelling exercises undertaken by IES and ROAM indicates that:

> "…perhaps the most remarkable result from all this modelling is that both studies agree that the cost differences between the three main scenarios modelled are really quite small, at least when analysed at this aggregate level. It is also salutary to note that the impact on GHG emissions is not great either."

Further, esaa notes that of the three scenarios the AEMC requested IES and ROAM to model, none included any form of locational pricing signal. As such, esaa questions the basis for which the AEMC's reaches the conclusion that implementing a Generator Transmission Use of Service (G-TUOS) charge is the most efficient response to provide for more effective locational and retirement decisions.

EGR Consulting commented that further modelling work should be pursued, with future studies reviewing and revising the current assumptions used. Key priorities identified include consideration of more extreme scenarios (higher targets/prices) and a finer grained examination of how generator retirement and new build renewable decisions might interact with transmission system development in a particular region.

G-TUOS – Cost with little benefit

The AEMC's proposed response to manage congestion is to introduce a new G-TUOS charge, with possible supplementation by a short-term congestion pricing mechanism. Set annually, the objective of the G-TUOS would be to provide a network cost signal to generators based on differences in the long-run marginal cost of transmission between different locations. G-TUOS is the AEMC's preferred option as it provides an "effective cost reflective signal and can inform both location and retirement decisions for all generators".

However, implementing a G-TUOS charge as currently proposed is likely to give rise to issues for both incumbent and new entrant generators. For incumbents with sunk assets and no ability to move, a positive charge simply acts as a penalty in addition to being located in an already congested area. As the charge would be revenue neutral, it is effectively a wealth transfer between generators in congested and non-congested areas and would not provide any recourse to incumbents to address the underlying causes of congestion.

New entrant generators often rely on signing long-term hedge contracts with energy retailers in order to finance new developments. The implementation of an annual charge that could vary from positive to negative over time could potentially make it more difficult to accurately forecast revenue and secure project financing and, as such, may actually act as a barrier to entry for new entrants.

Further, it is not clear that the implementation of a G-TUOS charge will act as an effective locational signal. The interim report notes that given the right price signals renewable generation may be flexible in its location decision only "at the margin." esaa considers that while the additional price signal provided by a G-TUOS charge may induce a marginal investor to change the location of new generation, for the majority of prospective renewable generation, which the AEMC see as a key driver of future congestion, the availability of renewable resources will likely dominate location decisions.

In this respect, esaa considers the AEMC proposal for Network Extensions for Remote Generators (NERG) is likely to provide competing and stronger signals to potential new renewable generators than a G-TUOS signal, which raises questions about its efficacy. Under the NERG proposal the Australian Energy Market Operator (AEMO) will identify areas where significant remote generation is likely, given the availability of renewable resources, and offer generators efficiently-priced connection contracts.

Analysis of alternative options

The Interim Report considers a range of alternative approaches to addressing congestion including ‘deep’ connection charges and negotiated firm financial access under Clause 5.4A of the National Electricity Rules. esaa in its previous response noted the current uncertainty around how Clause 5.4A should be applied and encouraged the AEMC to give further consideration to its potential ability to manage congestion.

However, the AEMC dismisses these options primarily on the basis that it is difficult to identify the ‘causer’ of reduced access on the shared network and therefore allocate direct compensation or the costs of network augmentation appropriately. The AEMC contends that: “It is not possible to pinpoint who is ’responsible’ for the loss of access.” In fact, the AEMC has canvassed the removal of Clause 5.4A altogether in light of the G-TUOS proposal.

However, esaa considers that the Interim Report does not fully substantiate its observation that power system flow modelling is unable to determine the ‘causer’ of reduced access for such alternative options, especially given that calculating the annual G-TUOS charge will involve in-depth modelling analysis of power flows including dispatch and peak demand scenarios as well as technical assessments of network spare capacity. As set out in the Association’s response to the First Interim Report, further consideration should be given to the application of Clause 5.4A rather than seeking to remove it as part of the G-TUOS proposal.

Further analysis and consideration required

esaa supports the conclusion of the due diligence report that there is scope for further work to be undertaken to more conclusively determine the location and materiality of congestion.

If the AEMC considers congestion to be a material issue within the NEM then the full range of options to address the problem need to be assessed and analysed in greater depth than is provided in the Second Interim Report.

Without such analysis, implementing an incremental response, such as G-TUOS, to address what the AEMC considers to be a short-term, transitional issue may prove to be inappropriate. This could result in wider implications for the efficiency of the energy market, which could be avoided if more comprehensive analysis had been undertaken.

For example, if, as the modelling undertaken to date suggests, increased congestion is likely to be material for the South Australian region, then there would appear to be merit in considering the appropriate options to address this location-specific congestion rather than necessarily implementing a long-term, NEM-wide charging arrangement that could potentially have unintended and unforseen consequences.

esaa notes the AEMC does not intend to provide a draft rule change proposal on its preferred option to manage congestion at the completion of this review, in order to facilitate further discussion on the options. esaa supports this approach and encourages the AEMC to work closely with industry to determine the materiality of this issue.

Connecting remote generation

The AEMC finds that existing network connection frameworks are unlikely to support efficiently-sized network connections that accommodate anticipated future generation from remote areas. It considers that lack of coordination may result in connection delays, inefficient duplication of connection assets and large cost impacts for consumers.

The AEMC's draft recommendation is a new Network Extensions for Remote Generators (NERG) framework for the planning, pricing and funding of network investment to remote areas. Under the proposal, network service providers (NSPs) would develop standard contract offers for generators based on a 'right-sized' connection asset for forecast generation in remote regions designated by AEMO. Generators connecting to the new asset would pay the price under the standard contract, with consumers bearing the risk of under-subscription by generators.

<u>A proportionate policy response to market and policy failures?</u>

esaa agrees with the AEMC that efficiently-sized network connection assets could benefit the electricity market but that disincentives for first-mover generators and NSPs may result in markets not delivering optimal network extensions when the full extent of future generation from a remote area is taken into account. Current connection policy frameworks may exacerbate these potential market and policy failures by inhibiting coordination and information sharing amongst generators and NSPs.

The NERG proposal would appear to be an attractive solution to the existing market and policy failures and broadly consistent with the thrust of transmission policy reform: it combines limited central planning with decentralised commercial decision-making and regulatory oversight. In theory, NERGs offer a mechanism to deliver timely, efficiently-sized and cost-reflective connection assets to a suitable remote area, with economic benefits accruing to the market as a result.

While acknowledging the potential of NERGs, esaa nonetheless has concerns that there are material challenges to the successful practical implementation of NERGs and that these challenges could prevent the potential benefits of NERGs being realised.

Foremost among implementation challenges is accurately forecasting future generation from NERG-designated regions. To accurately forecast and verify likely future generation, NSPs and AEMO will need to take account of complex and uncertain factors that include, at a minimum: the extent of the resource; the costs and/or viability of technologies; demand for load; the capability of the wider transmission system; the likelihood that planned/committed projects proceed; and future carbon prices.[1] As the design and pricing of the connection asset will be based

[1] Future carbon prices will be driven by economy-wide marginal abatement costs and domestic and international greenhouse policy developments – both of which are inherently difficult to forecast.

on generation forecasts, accurate forecasts will be central to a NERG delivering benefits.

Given the inherent difficulties with forecasting future generation from a region, NERGs entail an unavoidable risk that connection assets are *ex post* incorrectly-sized. The economic cost of building an under-sized NERG asset instead of incremental assets, as would likely be built under current connection frameworks, may not be significant (or even negative) as there is likely to be at least some economies of scale and scope benefits realised from even an under-sized NERG asset. However, in the event of an over-sized NERG asset, the economic costs of excessive capitalisation could be more significant and are to be borne by consumers through higher transmission charges feeding into higher electricity prices.

The AEMC justifies consumers wearing the stranded assets risk of NSPs on the grounds that consumers will capture most of the benefits of right-sized connection assets. Furthermore, the AEMC intends to give AEMO and the Australian Energy Regulator (AER) gate-keeping responsibilities designed to protect consumers by minimising the risk that excessive NERG assets are built.

While esaa appreciates the safeguards proposed by the AEMC, the broader policy design question of whether NERGs are a proportionate response to the market and policy failures identified by the AEMC is still outstanding. The answer to this question in large part depends on whether challenges to successful implementation can be overcome, and whether the potential benefits to the market outweigh the potential cost from overbuilds. The AEMC has not provided a quantitative assessment of the likely net benefits of NERGs, taking account of the risk of overbuild, and so an informed judgement on this question is difficult.

At this stage, esaa is inclined to support further development of the NERG proposal in light of the potential for efficiently-sized network extensions to reduce the economic cost of meeting the CPRS and particularly the expanded RET. However, esaa urges consideration by the AEMC of ways to address the significant challenges to practical implementation. As an imperative, the processes around AEMO and the AER's new responsibilities must be rigorous and transparent and include appropriate avenues for industry input.

<u>Additional concerns with NERGs</u>

In relation to the design of the NERG proposal, esaa considers that the framework for NERGs should still be required to operate within current open access frameworks for generator connection; that is, the network extensions are negotiated on commercial terms and with no obligation imposed on NSPs to undertake the investment. esaa also considers that designating a connection application, rather than connection enquiry, as the trigger for NSPs to develop a standard contract may be more appropriate.

esaa also notes the AER will be empowered to oversee and potentially disallow NERG project designs and standard contract offers, including a five-yearly review process designed to allow an adjustment to contract prices to reflect differences in actual and outturn costs. esaa considers this should provide appropriate incentives for NSPs to consider efficiencies in capital and operating expenditures. However, broad powers to re-open commercial arrangements can present risks for market participants which may not necessarily be able to be adequately resolved outside of the contractual process. esaa encourages the AEMC to recommend that the AER should be required to provide further guidance, potentially through guidelines, on the scope of the review process.

Inter-regional transmission charging

The AEMC finds that as the CPRS and RET are likely to lead to increased power exports from regions where new sources of particularly renewable energy emerge. However, under current arrangements there is no mechanism to allow for the sharing of costs for transmission infrastructure built to allow increased exports which means consumers in exporting regions may bear disproportionately the costs of delivering national emissions reduction and renewable energy targets.

The AEMC recommends a new inter-regional TUOS charging arrangement that obligates Transmission Network Service Providers (TNSPs) in exporting regions to levy a load export charge on TNSPs in importing regions, based on the cost of new and existing network assets that the exporting TNSP reasonably considers contributes to the capability to export to the importing region.

esaa notes the proposal for an inter-regional TUOS charge was originally developed as part of AEMC's National Transmission Planner (NTP) review, following which the Ministerial Council on Energy (MCE) directed the AEMC to develop further as part of the current review. esaa understands the proposals have been subject to prior consultation with industry stakeholders to date under the NTP review.

esaa considers that, as a general principle, it is reasonable that the cost of meeting national targets should be shared across all users of electricity and not be borne disproportionately by consumers in regions with significant renewable resources. To the extent that implementing the load export charge does not place undue burden on TNSPs, esaa considers that the proposed load export charge approach has merit in addressing the issues raised by the AEMC.

esaa notes that while the above arrangements should assist in addressing the issues within the NEM, the RET is a national target and will drive investment in generation and transmission in other jurisdictions as well. In addition to South Australia and Victoria, Western Australia is predicted to experience a significant increase in renewable generation, particularly wind. This will result in Western Australian consumers potentially bearing disproportionately the costs associated with the national RET but having no recourse to the cost smearing arrangements proposed for consumers in the NEM given the lack of interconnection. esaa supports further consideration being given to this issue by the AEMC in its final report

Transmission and Distribution networks

The AEMC finds that larger volumes of embedded generation and more variable network flows are likely under the CPRS and the expanded RET. It considers that both network operators and consumers could benefit if techniques to manage the change efficiently were developed, but finds that current innovation incentives are weak. Accordingly, the AEMC seeks views on a time-limited allowance for distribution businesses for approved innovation projects.

esaa welcomes the AEMC giving further consideration to the impacts of climate change policies on transmission and distribution networks in its Review. esaa agrees with the AEMC's assessment that current incentives for innovation within network regulation are weak and this represents a significant barrier to NSPs to manage and integrate emerging demand-side and embedded resources and develop new smart-grid technologies that will drive efficiency and emissions reductions in the future. Network businesses may be reluctant to invest in research and development in such activities if the regulator does not allow the business to recover those costs through time.

esaa notes the recommendation for provision of a time-limited innovation allowance was proposed as part of the AEMC's Review of Demand-side Participation. esaa offered support for such an arrangement in that review but notes that the AEMC is seeking further views on whether there is merit in applying the allowance as soon as possible, noting the ability of each business to access an innovation allowance is influenced by the timing of their periodic reset. esaa would support further investigation into measures to provide access to the allowance as soon as possible to all network businesses. Further, esaa considers that the AEMC should consider extending the proposed innovation allowances to transmission networks.

The AEMC also notes concerns from industry as to the increasing number of connection applications within distribution networks and the ability of network businesses to manage these applications. The Interim Report notes that the MCE has been considering this issue as part of its work to develop a national framework for distribution connections. While esaa agrees with the AEMC that "a timely completion of this process will assist in minimising the risk of inefficient outcomes as a result of connections to the distribution network", esaa notes that network businesses are already being subject to connection applications and that a reliance on the MCE process may not be adequate. esaa considers the AEMC should liaise with the MCE to ascertain to what extent further recommendations can be made in the final report to bring forward any key recommendations from the MCE work.

esaa also welcomes the confirmation by the AEMC that the NERG proposal would also apply to remote generators seeking to connect directly to the distribution network and agrees that this should also assist in addressing some of the concerns around connection.

Generation capacity in the short term

The AEMC finds that the current frameworks are inadequate to address the risk of capacity shortfalls in the short term following the introduction of climate change policies. Given the potential for significant disruption and costs, the AEMC recommends that AEMO's options to procure reserves be expanded. It canvasses views on mechanisms to provide short notice reserve capacity for periods close to dispatch and the need for some form of standing reserve panel whereby members would receive long-term payments for having capacity available to generate when called upon.

esaa has serious concerns with such proposals as they represent a subtle but significant departure from the existing energy-only market model. The proposal if implemented would serve to add to the already significant regulatory interventions in the energy market and further distort efficient market outcomes. esaa considers that such an approach raises fundamental market design questions about capacity that should be openly and transparently considered rather than resorting to incremental regulatory approaches such as standing reserves.

Energy-Only Market

Under the energy-only model, the only payment generators receive for their plant is the price of the electricity they produce – no payment is made for being available to generate. Generators are reliant on periods of higher electricity spot prices to make a return on capital and to generate sufficient revenues to fund new investment in generation capacity. The energy-only market has worked effectively over the last ten years to deliver some new investment (although little private sector baseload investment) and to provide an incentive for plant to be available during periods of tight supply and demand conditions.

However, the inherent volatility associated with spot market prices is a potential source of concern for governments and, in practice, governments demand a higher level of reliability than the market is designed to deliver. As such, various ‘safety net’ measures to the market, such as retail price caps and caps on the spot market price itself, have been introduced in an attempt to smooth out and reduce such price fluctuations to the end consumer.

Placing limits on the effective operation of the energy-only market acts to blunt the price signals that are required to reward generation and to indicate new investment is needed (and also to enable the demand-side to respond). This creates what some have called the ‘missing money’ problem – referring to the lost revenue which would have been earned by a generator in the absence of government-imposed constraints on the market.

Impact of interventions

esaa considers the effective operation of the energy-only market is also impacted by interventions to deliver capacity through mechanisms such as the reserve trader mechanism currently in place. Empowering the market operator with additional reserve procurement powers will simply introduce further distortions that may have substantial and difficult to predict impacts on generator behaviour, the wholesale market and investor decision-making.

For example, the AEMC observes that the implementation of a standing reserve panel:

> “…may lead to capacity being withdrawn from the energy market, where a revenue stream may be uncertain, in favour of guaranteed returns from participation in the standing reserve. To the extent that capacity withdrawn from the energy market needs to be replaced, energy options with a higher cost than those withdrawn are likely to be required, thus raising the

> average price of electricity, with no guarantee that the standing reserve would ever need to be deployed."

The AEMC also highlight that a further issue with the proposed arrangements is that the responsibility for managing the risks associated with under-supply are effectively transferred to a regulator and removed from market participants who are best placed to bear this risk and respond in the most efficient manner.

esaa agrees with the above observations and consider they highlight the inherent risk of ongoing interventions in the energy-only market.

As with the proposals for G-TUOS, esaa considers that enhancing reserve trader arrangements represents an incremental approach to dealing with what are fundamentally significant questions as to whether the energy-only market is capable of delivering new investment, given the present distortions, or whether some form of explicit capacity mechanism (to provide generators with sufficient revenue to reward their existing investments and with which to fund new investment) is required.

There are a number of capacity mechanisms, both market based and regulatory, which have been used with varying degrees of success in electricity markets both overseas and in Western Australia.

The issue of capacity has been reviewed by the COAG Energy Reform Implementation Group process and the AEMC's Comprehensive Reliability Review. The Reliability Panel commissioned market modelling that shows the energy-only market is capable of achieving the NEM reliability standard in the future in the absence of market intervention.

However, the energy-only market cannot be assumed to continue to function effectively under a high burden of regulatory intervention and financial crisis. While a major overhaul of the NEM energy-only design would represent a significant regulatory risk for the industry, which should not be contemplated in the absence of sufficient evidence demonstrating the benefits of change, the market framework may warrant a broader consideration than the current AEMC Review.

Regulated retail tariffs

The AEMC finds that the development of competitive and efficient energy markets will be inhibited if the costs of the CPRS and RET are not reflected in retail energy prices. It also notes that products enabling retailers to hedge carbon-inclusive energy costs may not emerge in the short to medium term. The AEMC's draft recommendation is that by the time the CPRS commences all jurisdictions retaining retail price regulation should have developed a timely and flexible adjustment mechanism to ensure that carbon-inclusive energy cost increases (and decreases) associated with the CPRS are reflected in retail prices.

esaa agrees with the AEMC evaluation that the current framework for retail price regulation is not sufficiently flexible to deliver efficient prices and services to retail customers following the introduction of the CPRS and RET. esaa has long supported the removal of retail price regulation where retail markets are contestable to deliver the most efficient pricing signals and to ensure appropriate investment, operation and consumption decisions. Retail price regulation in contestable electricity markets imposes considerable direct and indirect costs on the Australian community with little to no offsetting benefit. The case for removing retail price regulation in jurisdictions where retail markets are contestable is reinforced by the impending CPRS and expansion of the RET.

Retail price regulation currently occurs in a relatively stable wholesale electricity market environment. However, the CPRS and expanded RET represent a fundamental transformation of the energy market. The retention of retail price regulation in this new policy environment creates the real risk that retailers may be prevented from passing on, in a timely manner, higher wholesale, network, prudential and risk management costs associated with the CPRS and the expanded RET. This could result in significant losses for retailers and potentially threaten the financial viability of existing players.

For regulators, the task of setting appropriate retail prices that are competitive but still allow retail businesses to meet their costs and manage risks will be increasingly complicated. Faced with arguably unprecedented market volatility and no history from which to derive forecasts, there is an increased risk of regulatory error that could lead to retailer failure.

However, where governments choose to continue to regulate retail electricity prices, even where retail markets are contestable, the effect of regulation may be highly deleterious. Increased flexibility in the setting of retail price caps and an appropriate methodology that allows for the full and timely pass through of costs associated with the CPRS and the RET are therefore imperative to ensure a financially viable and competitive retail sector. The risks to the electricity market from the under recovery of carbon costs far outweigh the risk of over recovery in a contestable retail electricity market, particularly as any over recovery would be eroded through competition.

In this context, esaa supports the AEMC's finding that all jurisdictions retaining retail price regulation should implement timely and flexible adjustment mechanisms. The Association considers that a single, nationally consistent methodology for determining retail electricity prices should be developed and adopted across all jurisdictions. The AEMC, with responsibility for rulemaking and market development, should determine an appropriate methodology.

Any retail price setting methodology should be based on real, not modelled or arbitrarily determined costs, to encourage and facilitate competition, including through new entrants. Such an approach ensures that consumers face prices reflecting all efficient costs and can make rational consumption decisions as a result, which will be important for the efficient operation of the CPRS to provide least-cost emission reductions.

<u>Western Australia</u>

In the Western Australian context, it is now well recognised that retail prices are already capped significantly below the long run marginal cost of supply. Retail price suppression below long run cost is a major impediment to new generators and retailers entering the market and, if sustained over a long period, may lead to existing competitors exiting the market or – in the case of government-owned enterprises –

incurring substantial losses if market exit is not an option. The introduction of the CPRS and expanded RET will only serve to exacerbate and/or accelerate these impacts.

As there is currently no regulated process for formal and regular tariff reviews to ensure tariffs are set at efficient levels, and there is a lack of independence in price setting, esaa considers the current market settings are inhibiting efficient price discovery for informed investment.

In the absence of the introduction of full retail contestability with energy prices determined by competitive market processes and outcomes, esaa considers that retail price regulation in WA would be more effective if decisions were arrived at under a transparent, nationally consistent, framework for price setting as outlined above. Furthermore, to assist this transparency and avoid inherent conflicts of interest, esaa supports the removal of price setting decisions from the Minister for Energy and transferring the decision making powers to an independent authority such as the Economic Regulatory Authority.

System operation with intermittent generation in Western Australia

The Interim Report identifies that the expanded RET is likely to drive a significant increase in renewable energy in WA, particularly wind generation, which is likely to result in the system requiring increased frequency, voltage and inertia ancillary service support.

It finds that under the existing frameworks the dispatch merit order and balancing actions may not be least cost or result in fully compensating the balancing generator and that the costs of balancing and ancillary services may not be fully allocated to those parties causing them. Additionally, the AEMC identified that the ability for wind-powered generators to 'spill' into the system can trigger discretionary security-related dispatch decisions by System Management during times of low demand and that there is currently little transparency around the basis for such decisions.

The draft recommendation is that a phased reform package be adopted that firstly increases the transparency of dispatch and balancing actions and costs; and secondly, after a year, full cost-benefit analyses are undertaken on additional reform options. These could include increasing competition in balancing, improving the quality of information available regarding the likely output of wind and/or improving the accuracy of generation output forecasts through moving gate closure closer to real time. Other options identified include improving the cost-reflectivity of charges, with the aim of reflecting costs back to causers, reforming the procurement and cost recovery of ancillary services or providing financial incentives to System Management to minimise the cost of actions taken.

Any balancing actions taken by Verve Energy and 'spilling' output from intermittent generators is settled at the Marginal Cost Administered Price (MCAP), which uses the same calculation methodology as the Short Term Energy Market (STEM) auctioning process, except that the clearing price is equal to the price at which the aggregate portfolio supply curve intersects the *deemed demand quantity*. The deemed demand quantity is equal to real-time demand plus any unsupplied energy from scheduled resource plans. This ensures that the demand curve intersects the supply curve at the relevant price point to reflect the increased cost of scheduling more expensive generation to cover the outage. Because MCAP and deviation prices are based on bids and offers into the day-ahead STEM, an information asymmetry occurs such that the impact that any real-time events may have on short-run costs are not considered. Subsequently, MCAP may not be economically efficient in light of actual output.

In this context, esaa supports a more detailed assessment of the cost of balancing and ancillary services to inform potential reform of the provision of balancing and ancillary services to ensure greater cost reflectivity.

In considering potential reform options, increasing competition should be the first preference where practicable to ensure least-cost provision of the services. esaa also supports the principle that the costs of such services should be recovered from those parties causing them.

The AEMC discussed the option to provide financial incentives to System Management to minimise both the costs and volume of actions taken. Such an approach remains discretionary and is less transparent than providing market settings that enable market participants to determine the least-cost price and output through competitive market processes and outcomes.

Connecting remote generation and efficient utilisation and provision of the network in Western Australia

The AEMC found that the current frameworks in the Wholesale Electricity Market (WEM) for connecting new generation and providing an efficient transmission network are already exhibiting signs of stress. This is likely to be exacerbated by the additional amount of wind plant triggered by the expanded RET.

The AEMC considered that the "unconstrained" planning approach is likely to lead to inefficient over-investment in the transmission network, which will subsequently lead to an unacceptably long queue of connection applications. Furthermore, there is no formal mechanism to facilitate the coordination of connection applications to optimise the level of investment required. Finally, the AEMC concluded that locational signals may not be sufficiently accurate or visible to generators to ensure efficient locational decisions are made.

The draft recommendations are to:

- Assess the basis for generator access, including formalisation of non-firm generation connections, and a review of the planning standard currently used to provide "unconstrained" access for generation;

- Review the connections application process, including the release of more information to the market and segregating applications in the connections queue on a regional basis and potentially restructuring the connection application charge regime;

- A formal regime for transmission connection and augmentation where multiple connections are likely should be implemented;

- The workability and clarity of the regulatory approval processes for transmission network augmentations should be reviewed; and

- The charging regime for network augmentations should be reviewed to improve transparency, equity and efficiency of locational signals.

In assessing connection applications, network planning is undertaken on an "unconstrained" basis. That is, a new generation connection should not compromise the reliability and security of the network or the ability of other (existing) generators delivering their certified capacity through the network under normal conditions. This is based on an "N-1" security standard, which means that maximum generation output is not compromised in the event of the loss of the largest generating unit.

Western Power has adopted a queuing policy to systematically assess connection applications strictly in the order in which they are received. Given the requirements associated with the unconstrained network planning model, the assessment of network connections is, by necessity, a lengthy process. Much of the generation seeking access to the network is expected to be intermittent in nature and remote from load. Under the current frameworks, this will substantially increase the complexity of network planning and will likely require extensive augmentation of the transmission network above economically efficient levels.

This is likely to further lengthen network access lead times, which have already been raised as an impediment to efficient generation investment. The current security standard is unlikely to accurately represent the likely coincidence of output from connected generators at time of maximum demand, particularly in the case of intermittent generation. Further consideration of how to better define the security standard to better reflect actual system requirements and risk is required to ensure the optimal investment is made. Any consequential impact on the reserve capacity mechanism and the allocation of capacity credits should be carefully considered to minimise distortion.

Network access lead times may also be exacerbated by the current queuing policy and its current inability to distinguish credible applications in the queue.

It is recognised that the role of the queuing policy is not to pick "winners" or "losers" from prospective generation proponents. However, an inadvertent consequence of the queuing policy may be that the policy impedes productive efficiency by precluding connection of the most cost-effective new generation in the appropriate (least cost) order.

As a result, co-optimisation of generation and transmission investment may not be achieved, resulting in allocative, productive and dynamic inefficiencies.

On this basis, esaa agrees with the AEMC's draft recommendation as to the options that should be considered in respect of connecting new generation and optimising utilisation of the network. However, any final recommendations for fundamental and immediate reforms to the energy sector should be made cautiously and on the basis of careful cost-benefit analysis and industry consultation.

A complementary analysis should also be undertaken considering the interaction of the network connections process and reserve capacity mechanism in providing market signals to ensure the efficient and appropriate mix of generation capacity.