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Senate Select Committee on Fuel and Energy

By Email: fuelenergy.sen@aph.gov.au

Inquiry into Fuel and Energy – expanded terms of reference

The Energy Supply Association of Australia (esaa) welcomes the opportunity to make further submission to the Senate Select Committee on Fuel and Energy (the Committee) on its expanded terms of reference.

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 more than $120 billion in assets, employ 49,000 people and contribute $14.5 billion directly to the nation's Gross Domestic Product. esaa is fuel and technology neutral, and represents businesses that have investments across a wide range of fossil fuel and renewable generation technologies.

esaa notes that the Committee's expanded terms of reference is to consider the broad range of regulatory settings and taxation arrangements that may impact on the security of domestic fuel and energy supply in Australia, both currently and into the future.

esaa considers that to ensure continued investor confidence in the energy sector and ongoing security of supply, energy related policies should focus on the development of:

1. Open, competitive energy markets, nationally consistent and free from distortions as the corner-stone of Australia's stationary energy supply system.

2. Economically efficient, incentive based regulation of the monopoly parts of the system to facilitate competitive market outcomes, timely investments and reliable energy supply.

3. A reliable and sustainable energy supply system, where greenhouse gas emissions reductions are achieved at least-cost through rational policy settings and measures that are national, long term and complementary to competitive market arrangements; and

4. Nationally consistent and transparent market and regulatory settings that promote the efficient growth and development of the energy supply industry.

Against these principles, and in response to the Committee's expanded term of reference, esaa offers the following commentary on the issues that require further attention, in particular:

- Implementing a well designed emissions trading scheme that addresses the deleterious impact the scheme will have on the balance sheets of existing investors; manages the working capital requirements of the scheme; provides confidence in future emissions caps and targets; and ensures full cost pass-through to consumers.

- Ensuring stable, consistent and long-term regulatory frameworks are in place and there are adequate rates of return for investors.

- Instituting a renewed commitment to the regulatory reform process in the stationary energy supply sector.

- Reducing the impact of areas of regulatory burden that are compromising the objectives of the National Electricity Law (NEL) and National Gas Law (NGL) to 'promote efficient investment in, and efficient operation and use of, electricity [and natural gas] services for the long term interests of consumers'[1].

- Resolving taxation issues that may be impeding industry development and increasing unnecessarily the costs of operation.

Well designed emissions trading scheme

While esaa appreciates that the Committee, in its interim report of 7 May, has already considered issues associated with the Federal Government's proposed Carbon Pollution Reduction Scheme (CPRS), esaa maintains the position from its previous submission to this Committee that the implementation of a well designed emissions trading scheme (ETS) remains a critical measure to ensuring security of supply and investor confidence in long-lived, capital-intensive energy sector assets. However, the current design of the Carbon Pollution Reduction Scheme (CPRS) does not achieve this. The failure to address the energy industry's four critical design issues with the CPRS (as outlined in Attachment A) is having a significant impact on investor confidence.

<u>Impact on electricity generators</u>

The introduction of the CPRS in its present form, compounded by the impact of the current global financial crisis, will have a direct and immediate effect on the financial positions of a number of existing energy market participants. The government's assumption that there will be a ready supply of potential investors and/or debt and credit providers to take over any distressed assets resulting from the CPRS is simplistic and optimistic.

Private sector operators have already reported difficulty in refinancing existing investments and obtaining finance for new projects. Earlier this year, esaa surveyed over 40 electricity and downstream natural gas companies on the impact of the

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[1] The NEL and NGL apply to all east coast jurisdictions (Qld, NSW, ACT, Vic, Tas and SA). In Western Australia and the NT the Electricity Industry Act and Electricity Reform Act respectively provide industry specific regulatory regimes to optimise the economic efficiency of energy supply in the interest of consumers.

global financial crisis on the energy supply industry (full survey results are at Attachment B). Key survey results show:

- Australian energy businesses face a total refinancing obligation over the next five years of more than $50 billion.

- Generation businesses account for about $19 billion of total refinancing of which private sector participants account for about 78 per cent.

- New capital expenditure required in the generation sector to transition to a lower emission energy supply system is estimated at between $17 and $19 billion over the next five years.

- Generators will also need additional credit facilities to finance a further $21 billion worth of emission permits in the period to 2014 (not including the purchase of any future permits).

The introduction of the CPRS, compounded by the effects of the global financial crisis, could have serious implications for the short-term viability of the electricity markets and significantly undermine investor confidence, resulting in a reduced number of potential investors in the Australian energy sector for future developments, including low emission plants.

However not achieving policy confidence is also an unacceptable outcome. The industry now expects there will be a carbon constraint of some form in the future, but not having clarity on the size and timing of the constraint means that new investment will be significantly riskier. This will lead to new investment occurring only when prices have risen to a level where an acceptable risk premium can be earned. This is not an efficient investment approach and will be more costly for consumers in the long-run.

esaa supports the introduction of a well-designed, national emissions trading scheme as its preferred mechanism for delivering least-cost emission reductions and to ensure investor confidence in the sector. esaa considers there are just four critical issues that are not adequately addressed in the current CPRS design.

To ensure timely new investment and investor confidence in long-lived, capital-intensive assets, the CPRS needs to adequately address the stranding of coal-fired generation assets; commit to ten years of firm scheme caps followed by a ten-year rolling gateway; manage the working capital requirements for liable entities from the operation of the CPRS including taxation and auctioning; and ensure retail price regulation is removed.

Role of new technologies

With a greenhouse gas emissions constraint imminent, ensuring a portfolio of lower emission technologies (both in electricity generation and networks) are developed and available at lowest possible cost will be essential to maintaining Australia's energy security while maximising our prosperity. Significant government support for the demonstration but also research and development of a portfolio of potential lower emission technologies will be critical.

However, the success or otherwise of a range of lower emission technologies is still largely unknown. esaa considers that Australia should not preclude nuclear electricity generation as a potential source of supply to meet the growing demands of households and industry. Nuclear energy is a proven source of baseload power and could be economic at the forecast emissions prices in the medium to long-term. One disadvantage of nuclear is the long lead times from planning to commissioning. If, for example, carbon capture and storage or geothermal are not technically or commercially viable in the longer term, there may be few alternative generation sources available to provide a secure and reliable source of baseload electricity at moderate cost.

Stable and consistent regulatory frameworks with adequate rates of return

The security of Australia’s electricity and natural gas supplies is fundamentally dependent on ongoing investment in production and transportation infrastructure. Investment in long-lived capital intensive energy sector assets requires stable, predictable and long-term policy and regulatory frameworks along with adequate rates of return.

An uncertain policy environment can deter energy sector investments. As already highlighted, the current uncertainty surrounding greenhouse gas reduction policy and a failure to recognise the impact of substantial policy change on the value of energy sector assets increases the perception of sovereign risk and can undermine investor confidence in the sector.

As Australia’s energy sector must compete for investment with other sectors and other countries, investors will be attracted by competitive rates of return on their investment. In this regard esaa considers that the Australian Energy Regulator’s (AER) final determination in May 2009 to significantly reduce the rate of return on network investments not only runs counter to the policy intent of regulatory stability and predictability but could seriously threaten future network investment and innovation, with flow on consequences for the wholesale energy market and the extent and location of network congestion.

Networks will require significant expansion, reinvestment and reinforcement if they are to support and facilitate a new mix and pattern of generation in response to an emissions trading scheme and expanded RET. For example, the nature and levels of investment in energy infrastructure is likely to be affected by:

- Requirements to expand and reinforce networks to connect new renewable generation sources;
- Increased “peakiness” of the load profile;
- A need for upgraded interregional connections to maintain reliability while accommodating increased levels of intermittent renewable generation;
- An overall increase in demand for gas-fired generation and associated gas and electricity transmission infrastructure; and
- A need for innovation in network design, control and protection arrangements to support the increasing connection of distributed and renewable generation to distribution networks.

The set of required network infrastructure investments to respond to these policies and market signals will be significant. Elements of the regulatory regime do provide assurances relating to the recovery of actual capital expenditure. However, it does not follow, as assumed in the AER assessment of these issues, that sufficient investment will occur if the returns are not reasonable.

Regulatory reform process

The stationary energy industry has undergone a period of significant reform over the past two decades which has resulted in material efficiency gains and provided Australian consumers with some of the lowest delivered energy prices in the OECD. While Australia has stationary energy markets that have been cited as some of the better functioning in the world, most of the gains that lead to those conclusions were achieved some years ago and progress has slowed dramatically.

Renewed commitment to finalise the outstanding matters before the Ministerial Council on Energy (MCE) to complete the reform agenda is required. The progress of the National Energy Customer Framework and the continuing application of retail price regulation are two examples where further commitment to the reform process is required.

National Energy Customer Framework

esaa fully supports the creation of a single national framework for the regulation of retail supply of both electricity and gas as committed to under the Australian Energy Market Agreement (AEMA). The National Energy Customer Framework (NECF) represents an important component of this reform commitment and has been subject to a considerable review process to date under the MCE Standing Committee of Officials (SCO) Retail Policy Working Group process.

esaa notes that after an initial Council of Australian Governments (COAG) commitment to transfer the non-economic regulation of distribution and retail activities to the Australian Energy Regulator (AER) by 1 July 2006, the latest proposed commencement date for the NECF of September 2009 has now also been delayed. This is on the basis of the recommendation from the MCE meeting on 12 December 2008 that, given the importance of the package to households, further consultation was required, particularly with consumer groups. The MCE now proposes to introduce the framework some time in 2010.

esaa acknowledges the complexity of rationalising the various State and Territory based regulatory frameworks into a coherent national regime and developing clear and smooth transitional arrangements. However, esaa remains concerned that without a clear timeframe for transition there is a significant risk that this important reform process will be further delayed and that the COAG commitment to a single, national framework will not be delivered.

esaa considers there is scope for the MCE following the current round of consultation to develop further clarity around the timeframe and appropriate incentives for transition to the NECF.

Retail price regulation

Prices play an essential role in any market by efficiently signalling both the need for consumers to change their consumption patterns in response to the supply situation and for producers to consider new capacity investment. Retail price caps blunt these important price signals and ultimately prevent efficient market outcomes. Price regulation prevents the development of flexible and innovative pricing structures that could achieve more effective responses from demand side participants. As highlighted in numerous reviews, the risks for the supply of energy in suppressing retail prices are also significant.

Retailers are exposed to substantial risk in the wholesale market but, as a result of price caps, are unable to pass through additional costs to consumers. The introduction of a price on greenhouse gas emissions will add significantly to retailer costs. If there is not sufficient and timely provision for the full pass through of the costs of greenhouse gas abatement measures, the level of retail competition will be further constrained, potentially threatening the financial viability of existing players. Retaining retail price regulation puts much needed investment in the energy sector at risk.

Maintaining price regulation can also result in a decrease in competition and prevent the market from achieving efficient outcomes. This is because market forces, not government mandate, most effectively determine the competitive price for energy. In competitive markets free from distortions consumers face the full cost of producing energy which ensures that they consume the socially optimum amount. Government intervention to set prices at a politically determined level, for instance to protect certain classes of energy user, can artificially keep energy prices low and as a result prevents retailers from recovering full costs and creates barriers to entry for new suppliers, thereby preventing the achievement of a fully competitive retail market.

Many jurisdictions have frequently highlighted the desire to maintain price regulation in order to protect vulnerable customers. esaa acknowledges the need to support vulnerable, low income consumers, but agrees with the conclusion of the Productivity Commission that this objective is more effectively delivered “through adequate, well targeted and transparent community service obligations” rather than through inefficient regulation that prevents efficient market outcomes and internalises government social policy costs on companies and shareholders.

A study undertaken for esaa by CRA International into the effect of retail price regulation found that price regulation in contestable retail energy markets is likely to confer little or no public benefit but impose considerable direct and indirect costs, thus reducing overall welfare[2]. esaa considers that there is no sufficient public policy reason for maintaining distortionary and inefficient price regulation. With competitive market structures and competition and consumer protection law already in place, price regulation can safely be removed with flow on benefits to competitive outcomes.

With a competitive electricity generation sector and price regulated electricity networks, the retail market is by nature competitive and notorious for its narrow

[2] esaa June 2007 ‘The Effects of Retail Price Regulation in Australian Energy Markets’ available from http://www.esaa.com.au/reports-%26-studies.html

margins. Barriers for new retailers looking to enter the market are low as entry does not entail significant infrastructure investment. This is confirmed by the strong emergence of new, often niche, retailers especially in Victoria and South Australia. Full Retail Contestability also ensures consumers have the right to choose their supplier and has been introduced for all customers in all regions of the NEM with the exception of Tasmania, where it is scheduled for implementation in 2010.

The Australian Energy Market Agreement (AEMA) sets out the States and Territories' commitment to phase out retail price regulation where effective competition can be demonstrated and places the responsibility on the AEMC to carry out an assessment of effective competition.

esaa strongly supports the removal of retail price regulation in energy markets but has serious concerns about the approach adopted in the AEMA. In particular, esaa notes that even if an assessment identifies that effective competition is in place this will not automatically result in the removal of retail price regulation as has been the demonstrated case in South Australia. The Association also asserts that the AEMA should not start from an inherent assumption that energy markets are uncompetitive and need to be proved otherwise. The assumption should instead be that markets are competitive and the focus should be on identifying the structural impediments, such as retail price regulation, which impact on competition and distort efficient market outcomes.

However, esaa notes that the timetable for the AEMC-led reviews of effective retail competition has been delayed, with reviews of the ACT, NSW and Queensland arrangements now scheduled to be completed by the end of 2012. Given the proposed commencement of the emissions trading scheme in 2011, and the fact that the removal of retail price regulation remains at the discretion of jurisdictional governments, esaa considers the current AEMC process is unlikely to be sufficient to adequately resolve the ongoing impediments associated with retail price regulation.

Indeed, NSW has committed to retain retail price regulation until at least 2013 regardless of the outcome of their AEMC review; Western Australia has initiated real price rises for the first time since 1991 that still leave prices at least 25% below the recommendation from the WA Office of Energy; and the Supreme Court in Queensland has found that the 2008-09 retail price decision was not correct. Currently there is little appetite for cost-reflective retail pricing in many jurisdictions, as these three cases demonstrate, and there is real concern that this will continue, particularly in the face of significant price rises from the introduction of an emissions trading scheme.

esaa considers that where governments are unwilling to commit to removing retail price controls, there should be a consistent, national framework for the regulation of both electricity and gas retail prices that enables cost-reflective pricing and the full pass-through of emissions related costs to consumers.

Regulatory burden

esaa is concerned that the regulatory landscape for stationary energy supply is suffering from duplication and excessive demands on business, resulting in significant and undue burden. In many instances, the policies imposed have not been subjected to rigorous assessment and as such, it is not possible to determine if they are delivering benefits to consumers. esaa contends that in many cases, consumers are ultimately disadvantaged due to the costly imposition of many regulatory arrangements.

Duplication between energy specific and general legal obligations

One of the most significant drivers of regulatory burden and duplication in the energy sector is the overlap between many industry-specific regulatory obligations and obligations already imposed by generic legislation and statutory rules.

This is driven primarily by the fact that electricity and gas are typically seen as essential services, introducing major political and institutional risks for any government or agency which is seen to fail to ensure reliable access to energy supply. Historically, this risk was managed by government ownership or vertical integration of energy supply firms. This industry structure has unwound over the past two decades and produced material economic benefits to the Australian community.

For the reasons discussed above, energy is often seen as a ‘special case’ requiring detailed regulatory oversight, even where this oversight duplicates broader obligations imposed by laws governing:

- corporations;
- anti-competitive conduct or access to monopoly infrastructure;
- consumer protection; and
- occupation health and safety matters.

In some cases, this overlap is exacerbated by inconsistencies between State and Territory laws, so that an energy business may be subject to energy-specific obligations, and a number of inconsistent jurisdictional regimes (as can occur in relation to consumer protection).[3]

Even where this does not occur, the cost, complexity and uncertainties created by operation of general Commonwealth laws and energy-specific regimes can be significant. One example which remains unresolved is the potential for dual coverage of the national access regime under Part IIIA of the Trade Practices Act, and the electricity access regime set out in the National Electricity Law and associated statutory rules.[4] Until this issue is resolved, owners of nationally significant energy assets are required to contemplate the application of two existing access regimes applying to a single set of assets. Another example is that the gas pipeline sector consider that industry-specific regulation is unnecessary, and that the generic national access regime is sufficient to provide a framework for nationally significant gas transmission infrastructure.

In future energy policy-making there needs to be a closer regard to the actual need for energy-specific regulatory responses to issues that arise and are dealt with by

[3] See for example Productivity Commission Review of Australia’s National Consumer Policy Framework – Inquiry Report, Vol.2, p.X, 30 April 2008.
[4] A commitment to engage in a process of certification of the revised electricity and gas access regimes is contained in Australian Energy Market Agreement, Clause 13.3, but has not yet been carried out.

generic legislative regimes. In particular, a clearer linkage is needed between any special features of the energy supply chain and the need for energy-specific regulatory approaches.

A stronger focus on the extent to which costs and benefits of energy sector regulatory proposals are affected by existing generic obligations would also assist. While the esaa supports the leadership of the Ministerial Council on Energy in driving a series of complex and challenging energy reforms, the Office of Best Practice Regulation has published material that indicates that some of these reform proposals have not been subject to a consistent level of cost and benefit assessment required by the Commonwealth government. The preparation of Regulatory Impact Statements (RIS) is designed to address many of the issues identified above. In energy, however, this has not worked as well as it could, with a lower rate of compliance with key RIS requirements experienced over 2006-07 than in a range of other active reform areas.[5]

Expansion of energy information-gathering powers

An emerging area of regulatory burden with the potential to impose high costs on the energy sector is the use and expansion of energy-specific information collection powers.

New national electricity and gas legislation introduced over 2007-08 established significantly enhanced information-gathering powers for the AER. These powers were assigned for the carrying out of its important economic regulation and rule enforcement functions under the legislation. The operation of these powers, however, has been far more intrusive and problematic than anticipated by stakeholders at the time of their design and implementation. The major powers granted are the capacity to issue Regulatory Information Notices (RINs) and Regulatory Information Orders (RIOs). These empower the AER to specify the manner and form in which regulated energy businesses collect and maintain information.

These information instruments were intended to assist the AER in the conduct of its core economic regulatory functions. It is uncontroversial that economic regulatory bodies charged with regulating the prices, terms and conditions of infrastructure monopolies require the capacity to obtain information to assist in regulatory decision-making. In this context, governments accepted proposals to strengthen and standardise requirements in the national economic regulatory regime despite the protests from industry about the heavy handedness of the chosen measures. Since their implementation, a number of developments have occurred which mean these instruments have the potential to impose a significant regulatory burden on industry.

The first development has been their practical implementation and use by the AER. Energy distribution businesses have been served with notices that are up to 30-40 pages long, requiring in many cases the provision of information which the regulated business does not collect for its normal commercial operations, and the categorisation of existing information in a manner not consistent with current business systems.

[5] Office of Best Practice Regulation Best practice Regulation Report 2006-07, 21 December 2007, p.76

A further adverse development has been an increasing conflation in the intended roles of Regulatory Information Notices (designed as a specific one-off information request) and Regulatory Information Orders (designed as a document eventually able to be applied generically across multiple businesses). Practice to date indicates that RIOs have primarily been used as the basis of ongoing performance reporting, contrary to the explicit intention of the relevant provision, and that information notices are being issued without sufficient guidance as to the how the information collected will be used, or any assurance that further inconsistent information requirements will not be imposed in the lead up to future regulatory pricing reviews.

The second negative trend in relation to information-gathering relates to the tendency of wide information powers granted for one purpose to expand into other areas where more targeted approaches are sufficient. Since the introduction of RINs and RIOs, in response to the particularly intense information needs of monopoly pricing regulation, there have been a range of policy initiatives and proposals seeking to have similar instruments imposed on a wide range of market participants, such as electricity generation businesses operating in contestable market segments. These information powers are claimed to be necessary to support functions as diverse as:

- longer-term energy supply forecasting undertaken by the new Australian Energy Market Operator (AEMO);
- detailed forecasting and planning work of the newly approved body National Transmission Planner, operating as part of AEMO;
- the operation of the Short-term Trading Market and Bulletin Board for gas; and
- monitoring the compliance of energy retailers with the proposed National Energy Customer Framework (since rescinded).

Given emerging concerns over their use in the narrow application which the information powers were originally designed for, this suggests a wide range of energy sector participants may soon face an increasingly intrusive and unnecessarily burdensome information collection regime for no demonstrated beneficial purpose.

Complexity and cost of regulatory pricing reviews

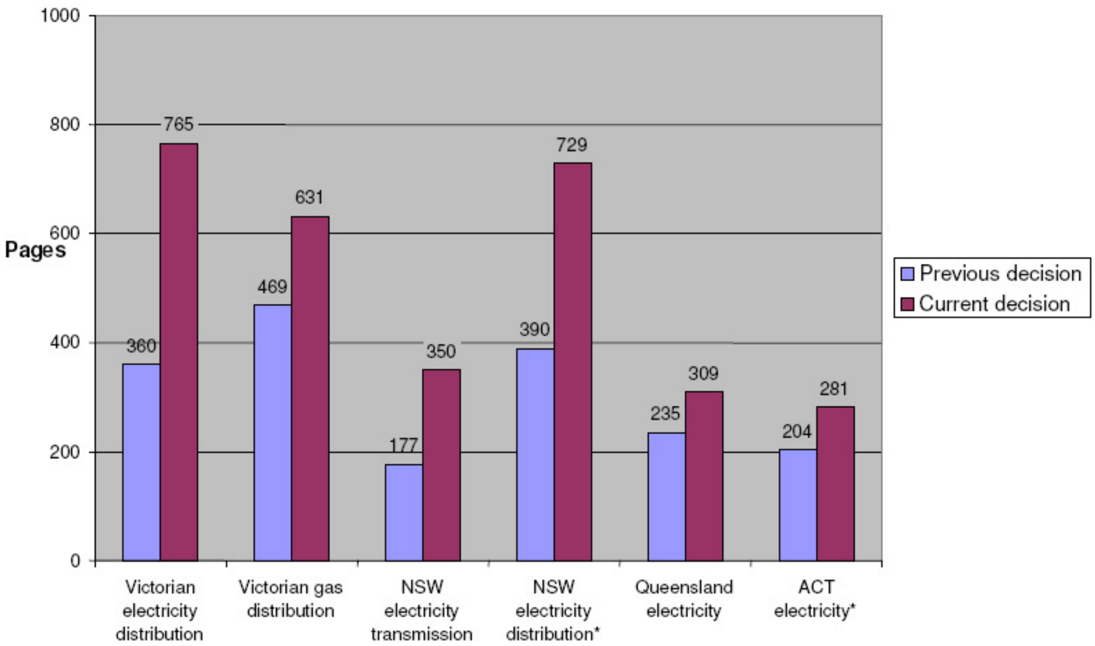
An ongoing area of regulatory burden across the energy sector is the increasing complexity and cost associated with regulatory pricing and revenue reviews.

These reviews typically determine maximum prices or revenues recoverable by regulated electricity and gas infrastructure owners. Most commonly, the regulatory reviews occur each five years. Regulatory reviews of this type involve significant commercial and public interest considerations, and as a deliberate measure there is designed to be a high degree of transparency around the process, factual basis and reasons for the decisions made. A striking trend, however, has been the growing length and complexity of the regulatory review process over time.

The increasing complexity and cost of such reviews can in part be attributed to a process of refinement of the operation of regulation, and is a reflection of the growing body of expertise and practice in energy regulation. It also arises, however, from an increasing tendency for regulatory pricing decision processes to evolve from high-level reviews of the reasonableness of proposed access terms or prices, into a detailed review of all aspects of the commercial operations of regulated infrastructure. As an economic regulator's expertise in this field is limited, these reviews are increasingly characterised by opposing expert views provided on detailed operational aspects of planned network investments, efficiency assumptions, and expected labour costs. Complexity of regulatory decisions is also driven by the increasing complexity of regulatory pricing arrangements adopted aimed at mimicking competitive processes.

One simple measure of the increasing complexity of regulatory price reviews over time is the tendency for regulatory pricing decisions to grow in absolute length. Examining a cross sample of energy regulatory decisions applying to electricity and gas infrastructure, it is clear that over the past decade, the size and complexity of the decisions has substantially increased. Figure 1 provides the raw total page length of the some recent regulatory pricing decisions, and compares it to the previous final regulatory final decision applying to the same infrastructure.

Figure 1 - Page length of selected past and current energy infrastructure decisions



Source: Victorian Essential Services Commission, QCA, IPART and Australian Energy Regulator websites.

Note: * denotes decisions which have been transitioned to the AER.

On current trends, the next round of regulatory decisions could reasonably be expected to produce regulatory decisions of over 1,000 pages in length. Underpinning these regulatory decisions can be up to a dozen or more expert reports, detailed annexes and other material supporting the primary decision.

The trend stands in stark contrast to the stated objective of the Ministerial Council on Energy reform program of streamlining regulation. It is also noteworthy that the trend towards increasingly complex and lengthy decisions does not seem to have been affected by the movement of responsibility of some economic regulation from State and Territory energy regulatory bodies to a single national body – the Australian Energy Regulator. This suggests the issue is systemic, rather than transitional, and needs to be addressed.

One key driver of the increasing complexity and cost of regulatory reviews is to be found in a specific design feature of current merits-based reviews for major energy determinations. Merits-based review is a positive feature of energy access regimes, and should be retained and strengthened. The concept of 'review on the papers' (which generally restricts the review body from considering new evidence not tendered in the review process) does, however, create some perverse consequences. For potential administrative review proceedings this feature incentivises the comprehensive lodgement and detailed consideration of extensive expert reports on all matters that could potentially fall under dispute in a final review determination. As a review feature, such an approach does positively address the potential for a party to seek to 'withhold' key information for strategic use in any administrative review stage. It is unclear, however, whether this potential efficiency benefit in relation to future administrative reviews actually outweighs the costly impact of the design on every individual price review undertaken.

One possible direction for reforming the increasing cost and complexity of price reviews is to recognise that the form and operation of incentive-based regulation applied to many monopoly infrastructure networks is likely to mean current costs are based on efficient industry practice. This opens an opportunity to consider simplified or 'fast-track' pricing or revenue review processes in circumstances, for example, where future access charges fall within historical trends, or are based on asset investment programs that have been independently assessed as prudent. There is a range of potential models for evolving regulatory processes away from their current cumbersome, lengthy and costly form. Further examination of these models is warranted.

The issues of growing cost and complexity in reviews is not limited to pricing assessments for monopoly infrastructure. Increasing complexity and cost is also evident even where regulatory reviews are focused on contestable or competitive market sectors such retail sales.

<u>Costs and inefficiencies created by 'split level' regulation of energy matters</u>

A further area of regulatory duplication and burden relates to the remaining dual layer of regulation to which many businesses in the energy sector remain subject.

The series of ongoing energy market reforms have been pursued with the objective of enhancing the national character of energy market regulation, reflected in the creation of national energy institutions - the Australian Energy Regulator and Australian Energy Market Commission - and reforms to nationally applicable energy laws and rules. Most recently, the 2006 Australian Energy Market Agreement sought to define the scope of a further set of national reforms centering on a national framework for distribution and retailing regulation. Annexure 2 of this Agreement defined a range of energy regulatory functions to remain state and territory responsibilities, and identified those to be transitioned to a national framework.

While the 'split' of functions and responsibilities that emerged by agreement between Commonwealth, State and Territory governments focused on promoting an efficient national energy market, inevitably the divisions of responsibilities has left areas of duplication and inefficiency. An example of this is in the key area of management of the reliability of electricity transmission and distribution systems. Under the Australian Energy Market Agreement primary responsibility on service reliability standards remain with State and Territory governments, while service performance incentive schemes and regulatory revenue setting are administered by the national AER. This can lead to the emergence of a critical disconnect between evolving service performance standards set at a jurisdictional level, and the adequate planning and funding of delivering these performance outcomes which is critically linked to decisions made in the AER revenue setting process.

A further example is in the area of technical licensing or business authorisations. This area is one of ongoing State and Territory responsibility, and licenses to operate electricity and gas infrastructure are typically granted either by State or Territory regulatory bodies, or in some cases directly by relevant Ministers on the advice of energy departments. Separately the Australian Energy Regulator has been given the role of monitoring, compliance and enforcement of national energy rules. In specific areas, these roles can intersect with compliance and monitoring responsibilities to create duplicative reporting and compliance arrangements. Examples of this include business performance reporting and quality of service and reliability reporting.

A final point is ensuring that the planned movement to national arrangements does not itself result in a net increase in regulatory burdens. Where transition to national regulation occurs it is important that associated reforms embody best practice regulatory approaches. Reforms which adopt a ‘lowest common denominator’ approach of adopting the regulatory system which imposes the highest potential cost on industry participants should be avoided. Often, lowest common denominator approaches (which can include those imposing the highest level of obligation) are developed in response to the particular historical and commercial circumstances of the original jurisdiction, and do not reflect an appropriate ‘least cost’ regulatory approach that is suitable for national adoption.

There is some evidence that in development of the national energy distribution and retailing framework this risk is emerging. There is also evidence of the risk in development of national network connection and capital contribution arrangements, where an increased role for the AER compared to current arrangements in some jurisdictions is being proposed. Under current proposals, the AER would be given the task of ‘pre-approving’ standard electricity distribution connection agreements. There are also emerging indications that in a positive area of identified national regulatory reform – the harmonisation of energy supply industry technical and safety regulation – there are risks of a ‘second best’ approach of prescriptive input-based regulation being adopted out of an overriding desire for a single approach.

<u>Duplicative energy efficiency and greenhouse schemes</u>

Energy efficiency and greenhouse gas emissions reduction schemes are an important area of emerging regulatory burden for energy sector participants. An increasing number of overlapping energy efficiency and greenhouse focused regulatory and market-based schemes are being developed and implemented at Commonwealth, State and Territory, and local government levels.

Initially, esaa understood these schemes were largely adopted with the objective of fostering momentum towards a national suite of emissions reduction and energy efficiency programs. As consensus has emerged for a national approach to emissions reduction targets, primarily through the CPRS, varying levels of government have reviewed the efficacy of their programs, and in particular the complementarity of schemes to the CPRS. To progress this reform, COAG agreed on principles of complementarity to guide jurisdictions to review and where appropriate streamline programs.[6]

The following table provides a list of schemes in state and territory jurisdictions categorised by primary objective, that identifies the timing of commencement, and status of the scheme based on the outcomes of any government-commissioned reviews.

[6] COAG Communiqué November 2008.

Table 1 – State and territory schemes

Primary Objective	Scheme / Jurisdiction	Commenced	Review Status
Renewable / Low emissions energy deployment	Victorian Renewable Energy Target	1 January 2008	To be transitioned into national Renewable Energy Target.
	Queensland Gas Electricity Scheme	1 January 2005	Scheme targets extended in 2008.
	Queensland 10% Renewable and Low Emissions Target		Unknown
Distributed generation	Victorian Solar Feed-in Tariff	1 July 2009	Review questioned objectives in context of CPRS
	Australian Capital Territory Solar Feed-in Tariff	March 2009	Not reviewed
	South Australian Solar Feed-in Tariff	1 July 2008	To operate for 20 years
	Western Australia Solar Feed-in Tariff	1 July 2010	Not reviewed
	Queensland Solar Feed-in Tariff	1 July 2008	Not reviewed
Energy Efficiency	Victorian Energy Efficiency Target	1 January 2009	Review not finalised.
	New South Wales Energy Savings Scheme	1 July 2009	Review advised continuation.
	South Australian Residential Energy Efficiency Scheme	1 January 2009	Not yet reviewed
Greenhouse Gas Abatement	New South Wales Greenhouse Gas Reduction Scheme	1 January 2003	Legislated to discontinue once a national scheme commences
	Australian Capital Territory Greenhouse Gas Reduction Scheme	1 January 2005	Likely to discontinue once a national scheme commences

COAG's consideration of the regulatory duplication and inconsistencies inherent in the diverse range of jurisdictional initiatives listed above has been incremental to date. At its November 2008 meeting, COAG established principles which effectively permitted the continued proliferation of State-based feed-in tariff schemes with no clear timetable for their removal or transition into a consistent measure.[7]

[7] COAG Communiqué November 2008.

Furthermore, the COAG-announced National Partnership Agreement on Energy Efficiency[8] gives little confidence of a more consistent national approach on energy efficiency measures and in particular, the three state-based energy efficiency trading schemes.

Taxation

As an industry that is undergoing technological change and facing new constraints on greenhouse gas emissions, there are new areas of taxation treatment that esaa considers are in need of specific attention. The following provides commentary on the current tax treatment of geothermal energy exploration and the proposed tax treatment of activities under the Carbon Pollution Reduction Scheme.

Geothermal exploration

esaa considers that an anomaly in the *Income Tax Assessment Act 1997* (ITAA) disadvantages companies investing in exploration for geothermal energy resources, relative to exploration for traditional hydrocarbon energy resources and other minerals.

Division 40 of the ITAA, does not currently recognise exploration for geothermal resources, resulting in a divergent and discriminatory taxation treatment relative to exploration for other resources. This anomaly is likely to be unintended, and is inconsistent with broader government policy to encourage a rapid transition to a lower greenhouse gas emission intensity energy supply system. esaa considers that relatively minor amendments to Division 40 of the ITAA would correct this anomaly and we have provided suggested amendments in Attachment C for consideration.

GST and emissions trading

As foreshadowed in the CPRS green and white papers, Schedule 2 of the *Carbon Pollution Reduction Scheme (Consequential Amendments) Bill 2009* defines Australian Emission Units (AEUs) and other eligible units (such as Kyoto units) as personal property for the purposes of GST. Together with numerous other stakeholders, esaa has consistently opposed the application of GST to AEUs due to the significant financing implications and the potential to create distortions between domestic markets and overseas transactions.

It is anticipated that under the CPRS, the energy supply industry will have an annual compliance bill in the order of $4 billion. In an environment where access to working capital is already constrained, raising an additional 10 per cent to cover the application of GST will significantly increase working capital requirements. One estimate is that the 'imposition of GST would affect business cash flow by about $50,000 to $100,000 a year for 1 million tonnes worth of emissions permits.[9]

The Consequential Amendment Bill also clarifies that the import of overseas units, such as Kyoto units will not be subject to GST. esaa has obtained advice which indicates that this treatment could be a distorting factor in a taxpayers choice to hold a Kyoto unit over an AEU. In addition, the current treatment may prevent further

[8] COAG Communiqué July 2009.

[9] "GST To Apply on Permits" – The Australian Financial Review – 11 March 2009 Pg 9

harmonisation with overseas schemes such as New Zealand where a GST-free treatment has been adopted.

esaa considers that the proposed GST treatment does not meet Government's stated design objectives of simplicity, efficiency and equity. A preferred approach of affording emissions permits GST-free status would achieve this aim, avoiding the current unnecessary complexity as well as significantly reducing compliance costs.

Tax treatment of administratively allocated permits

esaa does not support the Government's position that administratively allocated permits provided for under Part 9 of the *Carbon Pollution Reduction Scheme Bill 2009* should be subject to tax. This will result in considerable cash flow implications for liable entities and may potentially bias taxpayer decisions to acquit or sell rather than bank administratively allocated permits in order to avoid incurring an unfunded tax liability. This runs counter to the tax objectives of the CPRS and could potentially introduce distortions to secondary markets if significant volumes of administratively allocated permits are sold.

Stamp duty

esaa notes that generally stamp duties are outside of the federal government's jurisdiction. However, under clause B4 of the *Intergovernmental Agreement on Federal Financial Relations* which operates from 1 January 2009, State and Territory Governments agreed not to levy stamp duties on the transfer of emission trading permits after 1 July 2013. esaa understands that all State and Territory Governments have responded to Treasury indicating that stamp duty will not be levied on permit transactions. esaa would welcome public confirmation of this outcome in order to provide certainty to industry.

Conclusion

As domestic demand for energy continues to grow, Australia will be challenged to meet the coincident requirements of maximising economic prosperity while maintaining Australia's energy security and delivering a lower emission energy supply system. Unlocking the potential of Australia's energy markets will be fundamentally dependent on achieving:

- A well designed emissions trading scheme that addresses the deleterious impact the scheme will have on the balance sheets of existing investors; manages the working capital requirements of the scheme; provides confidence in future emissions caps and targets; and ensures full cost pass-through to consumers;
- Stable, consistent and long-term regulatory frameworks that ensure adequate rates of return for investors;
- Renewed commitment to the regulatory reform process in the stationary energy supply sector;

- A reduction in the current regulatory burden that compromises the objectives of the National Electricity Law (NEL) and National Gas Law (NGL) to 'promote efficient investment in, and efficient operation and use of, electricity [and natural gas] services for the long term interests of consumers'[10]; and

- A taxation system that does not impede industry development or increase, unnecessarily, the costs of operation.

Yours sincerely

Brad Page
Chief Executive Officer

[10] The NEL and NGL apply to all east coast jurisdictions (Qld, NSW, ACT, Vic, Tas and SA). In Western Australia and the NT the Electricity Industry Act and Electricity Reform Act respectively provide industry specific regulatory regimes to optimise the economic efficiency of energy supply in the interest of consumers.

energy supply association of australia

Attachment A: Carbon Pollution Reduction Scheme - Amendments

There are four critical issues not adequately addressed in the current CPRS design. esaa's support for the CPRS is conditional upon these issues being resolved. Once these issues are resolved, esaa supports the introduction of the CPRS as soon as practical.

To ensure security of supply and investor confidence in long-lived capital-intensive energy assets, the CPRS needs to:

1. Protect the balance sheets of stranded coal-fired generators through the allocation of additional permits

- The CPRS needs to adequately address the stranding of coal-fired generation assets. A measured transition to full auctioning (as proposed in most other schemes developed to date) would enable a greater volume of permits to be administratively allocated to affected generators to ensure there is no disproportionate loss in economic value on the sector's balance sheets;

  - The environmental integrity of an ETS is not dependent on bankrupting existing generators that have provided clear benefits to households, businesses and large industrial producers. The environmental integrity comes from the choice of emissions caps rather than the way permits are initially allocated.

  - The allocation of 130.7 million permits over five years means the electricity sector will have to purchase 87% of its emissions from day one at a cost of $55 billion in the first decade. In the first eight years of the EU ETS, only 3-7% of all permits will have been sold with the rest administratively allocated.

  - The administrative allocation of an insufficient number of permits to coal-fired generation assets in the transition to an ETS could have serious implications for the short-term viability of the electricity markets due to the financial distress of a significant number of generators. Impairing the balance sheets of coal-fired generation assets sends a poor signal to future investors about the Government's willingness to make substantial policy change and strand electricity sector assets.

  - The CPRS allocates 130.7 million permits to coal-fired electricity generators in the first five years of the Scheme valued at less than $3.5 billion (real). Two of three sets of Government modelling suggest approximately $10 billion of permits would be required to offset the asset value losses experienced by coal-fired generators in the first decade. While industry modelling suggests the asset value losses are much greater than this and extend well into the second decade of the Scheme, the Government's results suggest 500 million permits would be required to secure future investor confidence in the sector *(amending the legislation from 130.7 million permits to 500 million permits would more accurately reflect the Government's modelled asset value losses.*

2. Deliver 10 years of firm emissions/scheme caps followed by a 10 year emissions target range (gateway)

- The CPRS needs to increase the term of the firm scheme caps from 5 to 10 years followed by a 10-year rolling gateway to ensure there is sufficient information for investors to commit to long-lived capital assets and deliver a lower emission energy supply system.

3. Provide future settled contracts at permit auctions to enable liable entities to manage cash flows

- The CPRS needs to ensure electricity generators can manage the working capital requirements of the Scheme. The Government needs to provide forward settled permit contracts/deferred payment arrangements to ensure liable entities can participate in the auctions and facilitate future electricity contracting (generators will need to secure $10 billion worth of permits to continue forward contracting).

4. Remove retail price regulation

- The CPRS needs to ensure retail price regulation is removed. Efficient prices are necessary to provide the appropriate signals for new investment and without full cost pass through the viability of retailers and the entire energy supply industry is at risk.

There are just four issues that need to be adequately resolved for esaa to support the CPRS.

esaa
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Global Financial Crisis and the energy supply sector

Summary

esaa surveyed energy sector businesses to better understand the impact of the global financial crisis on the energy supply sector. 40 businesses responded to the survey, with only two generators and three network businesses not responding. As not all businesses responded, the results should be considered conservative.

The energy sector will require significant additional capital in the next five years. The results suggest over **$97 billion** is needed to refinance existing generation and network assets and to invest in both existing and new assets.

Energy sector capital requirement – next five years	
Refinancing - networks	$29 billion
Refinancing - generation	$19 billion
Capital expenditure on existing & new generation assets	$18 billion
Capital expenditure on existing & new network assets	$31 billion
	$97 billion

In addition to this $97 billion of capital, electricity generators estimated they will need additional credit facilities to finance **over $20 billion** worth of permits in the next five years, not including any credit that may be required to finance future permits to enable the contracting forward of electricity.

Total refinancing obligations over the next five years are more than $48 billion, with $29.1 billion in network assets and a further $18.9 billion in generation assets. 60% of network refinancing will occur in the next two years, while 45% of generation refinancing will be required in the second year of the Carbon Pollution Reduction Scheme (CPRS). The private sector accounts for 78% of the generation refinancing obligations and 40% of network refinancing. 45% of all debt is currently from international sources.

New capital expenditure on existing generation assets over the next five years is estimated at more than $6 billion while modelling for esaa by ACIL Tasman suggests a further $33-35 billion of new generation investment will be required in the next ten years to accommodate both the CPRS and expanded renewable energy target. If only a third of that is required in the next five years that would add a further $11-12 billion (survey results were incomplete for new generation investment). New capital expenditure on both existing and new network assets is expected to be more than $31 billion over the next five years.

A number of key themes emerged from the survey that are critical to the industry's ability to source the required capital in coming years:

- The number of foreign banks in Australia has reduced significantly with the remaining banks reluctant to issue debt.
- The energy sector is competing with all sectors for equity and debt and capital is scarce.
- The market capitalisation of major institutions has declined dramatically over the past 18 months.
- Risk margins/credit spreads for the energy sector have increased substantially in the past two years – 200 to 350 basis points.
- There are now more onerous covenants and restrictions on refinancing, while the tenor of debt renewals has shortened to no more than three years.
- The Government's bank deposit guarantee has constrained the liquidity of non-bank lenders.
- Access to new equity is severely restricted given the recent loss in asset values across the economy and banks are seeking lower gearing ratios when equity finance is in short supply. Equity premiums have also increased.

Policy implications

There are a number of government/regulatory policies that are exacerbating the impact of the global financial crisis on the energy sector including: the largely unmitigated impact on the balance sheets of generators from the introduction of the CPRS; the Australian Energy Regulator's (AER) draft proposal to significantly reduce the rate of return on network assets; the crowding out of non-bank private sector lenders through the provision of a guarantee for deposits and wholesale funding for banks, building societies, credit unions and State and Territory governments; and the proposed support for the commercial property sector through the Australian Business Industry Partnership directing resources away from other sectors including energy.

The administrative allocation of a sufficient number of permits to coal-fired generators to mitigate the serious balance sheet implications from the introduction of the CPRS, an adequate rate of return for network assets over the next five years, and an end to distortionary Government policies that favour some sectors and reduce the pool of funds available to the energy sector during a period of significant capital requirements and constraints are all required to ensure security of energy supply and investor confidence in the sector going forward. In the absence of this optimal policy response, the industry may need to consider whether a government-supported energy sector financing facility is also required.

Carbon Pollution Reduction Scheme

The energy industry is facing a period of fundamental and ongoing change. The long-term prospects of the current generation assets will depend on the timing and design of the CPRS, the cost of domestic abatement, and the cost and availability of international abatement permits. New lower emission generation investment will also drive the need for significant new investment in electricity and gas networks/pipelines.

Industry modelling, along with two of the three sets of government modelling of the CPRS, show that the proposed level of administratively allocated permits provided under the Electricity Sector Adjustment Scheme (ESAS) does not adequately offset the likely loss in asset value for coal-fired generators. The global financial crisis is compounding this effect in the short to medium term by making it harder for businesses to negotiate refinancing arrangements, finance new investments and fund the purchase of emission permits.

The failure of the CPRS to adequately recognise the significant asset value losses from the introduction of the Scheme will result in the immediate write-down of generation assets. This will significantly reduce, and in some cases could extinguish, the equity in the assets leaving unacceptably high gearing ratios. The stranding of electricity sector assets, coupled with the ongoing future uncertainty around longer-term abatement objectives and the extent of so-called "complementary" measures such as renewable energy targets, feed-in-tariffs and energy efficiency targets, will increase the risk premium applied to the sector. In a tight capital market, the ability of generation assets to attract new sources of equity and/or debt will be extremely difficult given shortened asset lives, the relative 'riskiness' of future revenues, high operating costs (within year permit costs for some facilities will be at least $400 million in addition to ordinary operating expenditure), and the significant site restoration and employee entitlement liabilities that will need to be met upon closure of the asset. Without new debt/equity injections, there could be premature closure of plant before new lower emission plant can be planned, permitted, financed and constructed, jeopardising security of supply.

AER's Weighted Average Cost of Capital

The outcome of the AER's current cost of capital review will have critical implications for the future operation of the national energy market, as it will shape investment incentives for a range of energy infrastructure over the next decade. However, the proposed draft statements released by the AER do not incorporate a broad assessment of the impacts of a range of key challenges and risks facing energy infrastructure development.

One important challenge will be ensuring Australia's energy infrastructure is able to attract the required investment following the introduction of climate change policy initiatives such as the expanded renewable energy target and CPRS. These policies will result in a strong need to fund additional investments to transform and strengthen electricity network infrastructure to facilitate carbon reduction goals. This need will be additional to the already substantial investments required to renew a generation of ageing electricity infrastructure and maintain high levels of reliability while meeting growing demand.

The global financial crisis represents an additional significant risk that the review needs to take into account. Major disruptions in the operations of both Australian and international capital markets reinforce the need for the AER to adopt a cautious and prudent approach which fully accounts for current market conditions and expectations. This environment provides a strong imperative to reconsider aspects of the AER's proposed cost of capital approach and avoid 'step-changes' in both cost of capital values or regulatory methodologies.

Efficient and timely investment in energy networks is a critical component of a competitive, safe and reliable energy supply system. At a time of significant challenge for the sector, it is important that the necessary incentives are in place to ensure investor confidence to deliver much-needed investment. Reducing the return on capital for these investors, at this time of great risk, would be counterproductive to the interests of the sector as a whole, including consumers.

Survey results and themes

Key survey results

The esaa survey of Australian energy sector businesses reveals the scale of the refinancing task in the short to medium-term:

- Australian energy businesses face a total refinancing obligation over the next five years of more than $48 billion[1].
- The following table provides an annual breakdown of refinancing obligations for generation and network businesses.

	Networks ($ billion)	Generation ($ billion)
2009-10	10.3	3.2
2010-11	7.2	2.8
2011-12	5.9	8.4
2012-13	3.5	3.3
2013-14	2.3	1.0

- Of the total amount of refinancing over the next five years, network businesses account for $29.1 billion and generation businesses account for $18.9 billion.
- Refinancing obligations over the five years represent a third to one half of the entire existing asset base for the Australian energy sector.
- Private sector participants account for about 78% of total refinancing in the generation sector over the survey period.
- Private sector participants account for about 40% of total refinancing in network sector.

[1] Two generation businesses and three network businesses had not finalised/responded to the survey at the time of writing this paper.

- Most private sector participants reported a debt obligation to international banks – the average response was around 45% of debt from international sources.

The survey also provided numbers on capital expenditure budgets:

- Planned capital expenditure on existing generation assets over the next five years is more than $6.3 billion.

- Planned capital expenditure on existing and new network assets over the next five years is more than $31.2 billion.

Survey participants expect to spend more than $21 billion over the next five years purchasing carbon permits (not including any future permits that may be required for future electricity contracting). The annual spend on permits rises from about $4 billion in 2010-11 to about $4.6 billion in 2014-15. Respondents assumed differing permit costs in the initial year, ranging from $15 to $30 per permit. The average price equates to about $22.50 per permit.

Comments on the global financial crisis

The global financial crisis is having a direct and immediate impact on private sector participants in the energy supply sector, most notably emissions-intensive generators. These businesses often have a number of equity owners and multiple debt providers including domestic and international banks. While this reduces the individual investor risks of purchasing and funding large sunk assets, it makes the process of refinancing more complicated.

State-owned corporations indicated that they generally had ready and direct access to funds to refinance existing assets and invest in new network and generation assets through State-based treasury corporations.

Key themes from the general comments to the survey on the state of global debt markets included:

- The number of foreign banks operating in Australia has reduced significantly in the past six months and many of the remaining banks are reluctant to refresh or issue new loans. One respondent noted that there are only 11 banks in the world with a AA+ credit rating – the top four Australian banks are in this category.

- The withdrawal of international banks is impacting all sectors of the domestic economy. The Australian energy sector is competing with other major corporate businesses that are also seeking new sources of scarce credit from the Australian banking sector.

- The market capitalisation of the major international institutions has declined dramatically in the past 18 months. One participant provided a chart of the market values of 15 major financial institutions in July 2007 and January 2009 that shows the full extent of the write-down in the balance sheets of the major banks (see attachment 1).

- Risk margins and credit spreads for the energy supply sector have increased substantially in the past two years – in the order of 200-350 basis points, depending on the credit rating of an individual business or the structure of a particular investment project. In some cases, businesses have found that the cost of capital is not the problem; banks are just not prepared to write new business until the full extent of the global financial crisis is better understood.

- Banks are placing more onerous covenants and restrictions on any refinancing. In many cases, banks are requiring more secured financing, lending only to higher credit rated entities, including additional review events, and requiring higher levels of interest cover.

- The tenor of debt renewals has shortened considerably. A number of participants said that banks would not currently consider anything longer than three years.

- There is more due diligence on existing and new projects, resulting in greater delays in finalising any financial transaction.

- The Australian Government's decision to implement the Bank Deposit Guarantee Scheme has constrained liquidity and increased the market spreads of non-bank lenders. This may flow through to increased debt financing costs for participants including State and Territory-owned corporations that are not backed by AAA-rated governments (financing issues for State and Territory governments have since been addressed).

Participants commented that access to new equity is severely restricted given the recent loss of asset values. New investors are reluctant to enter the market given the uncertain level and timing of future carbon costs and the general decline in equity investments. Banks are seeking lower gearing ratios for new energy sector transactions at a time when equity finance is in short supply. Equity premiums have increased as a result. Current equity holders are reluctant to invest further funds into assets that have lost significant value in recent times.

The Australian Energy Market Commission commissioned S3 Advisory to undertake a review of financial market conditions and the availability and cost of capital for investment as a result of the introduction of an emissions trading scheme. The S3 Advisory report was finalised in December 2008. The comments made in that report reflect a number of the observations in response to the survey:

- Debt providers are now reducing their exposure and requiring equity providers to take more of the risk, therefore increasing equity risk premiums.

- Greater ability by providers of capital to be more selective in allocations of their capital, therefore requiring more reward for lower risk.

- Equity providers are risk-shy given the losses faced by some equity providers since the credit crisis began.

A summary of the key findings of the S3 Advisory report is provided at attachment 2.

<u>Comments on the AER's weighted average cost of capital draft determination</u>

Those that commented on the AER's draft decision to reduce the level of the WACC indicated that it would substantially reduce the overall earnings for network businesses facing regulatory resets. This is at a time when both equity and debt margins have increased substantially.

Participants commented that the extent of the global financial crisis and the risk premiums for equity investments have both increased dramatically since the AER considered its draft WACC decision.

The reduction in the WACC would have significant ramifications on the ability of network operators to access debt and invest in network assets:

- Debt providers could factor in an additional “regulatory risk” margin for network investments. This could be reflected in future credit ratings and result in higher debt margins.

- Most network investments have lives beyond 20 years. Investors will be reluctant to make such investments if long-term returns are significantly reduced.

- Networks will only invest on the basis of reliability requirements.

- There will be little or no incentive to invest in discretionary projects such as ‘market benefit’ investments, upgrades to interconnectors and major flow paths, and investment in smart networks to facilitate distributed generation and demand management initiatives.

The AER is currently considering its final decision on the setting of the WACC for future revenue determinations. The esaa, the network associations and the network businesses have put forward submissions to the AER detailing the deficiencies of the draft review. The AER has sought to extend the timeline for final report on the WACC review from 31 March 2009 to 1 May 2009.

General comments on the Carbon Pollution Reduction Scheme

Survey respondents raised the following points regarding the Carbon Pollution Reduction Scheme:

- The financial impact of acquiring permits on short-term cash flows for generators differed between businesses, most notably whether the business was privately or publicly owned. Anticipated levels of permit cost pass-through also varied significantly, although no coal-fired generator forecast full recovery of permit costs.

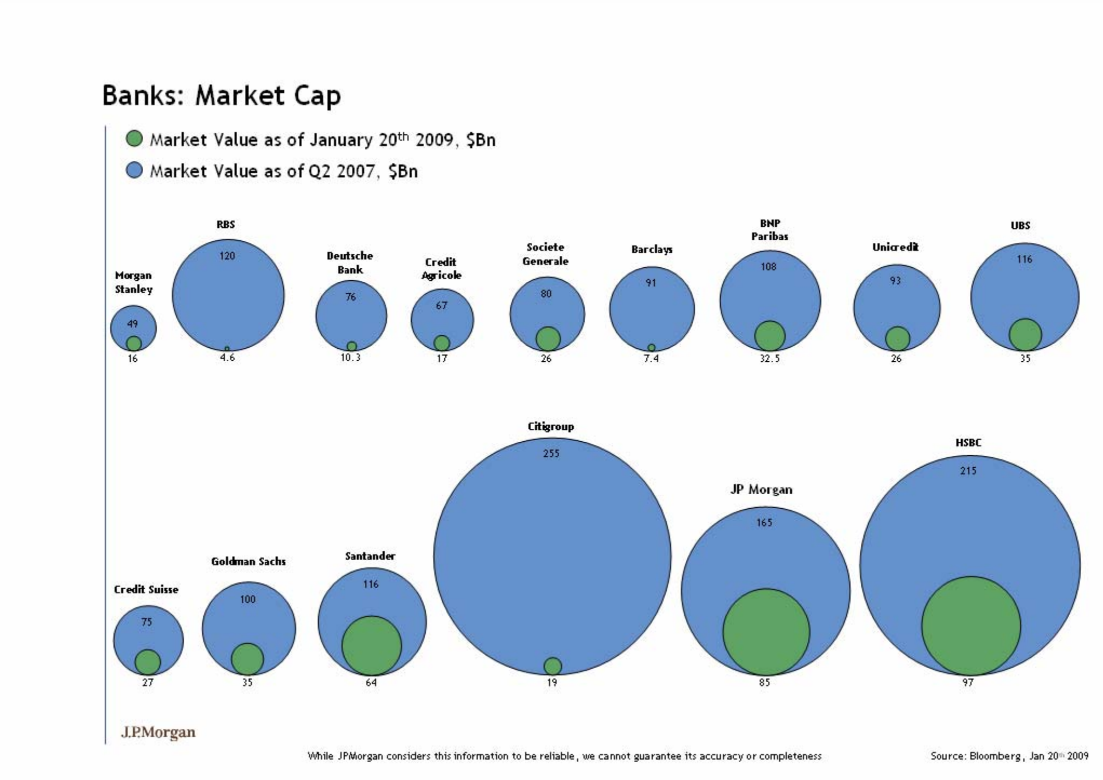
- Many participants noted that the introduction of the CPRS has significantly altered the risk profile of the industry, further increasing risk premiums for the generation sector.

- A number of businesses are operating under financial arrangements that did not envisage such a large shift in operating costs and consequently they are not currently able to access credit facilities to cover the additional cost of acquiring permits.

- The CPRS will place considerable strain on the finances of the electricity sector. The decline in the asset values of some plant may trigger debt repayments under existing debt agreements or debt covenants. Financing arrangements between debt providers and generation businesses generally include provisions that enable financiers to withdraw loan facilities or accelerate loan repayments in certain circumstances.

- The CPRS may provide the trigger for debt providers to review existing debt covenants. Borrowings may become payable earlier or the borrower may be given a period to convince their financiers that the facility should not be cancelled, failing which the borrowing becomes repayable. Refinancing would likely involve higher cost debt and larger debt repayments, exacerbating the financial stress faced by the generator.

Attachment 1: Market capitalisation of major international banks, 2007 and 2009



Attachment 2: S3 Advisory, Final Report to the AEMC: Financing the Future Energy Sector Investments in Australia

The AEMC commissioned the report as part of its review of the energy market frameworks in light of climate change policies. The report involved a series of interviews with market participants, debt and equity providers, ratings agencies and other stakeholders.

The report examined the issues associated with the financing of future energy sector investments in Australia and in particular the allocation and cost of capital to the sector as a result of a CPRS and RET out till 2020. The report deals with these issues at an aggregate and energy sector level rather than a project-specific level except in a number of key areas.

Given the effect of the credit crisis, many project proponents seeking capital will need to be significantly more sophisticated in their approaches to capital providers. Project proponents will need to understand the requirements of the capital providers and their strategic objectives for investment. It will not be sufficient for the investment evaluation to be rigorous, the returns attractive and the risks seen to be removed/managed or appropriately priced.

<u>Access to capital</u>

Access to capital has become increasingly difficult as a result of the credit crisis and risks are perceived to have risen for investments in the energy sector as a result of the commitment to introduce a CPRS and RET. Findings include:

- Competition for global capital will be intense given the demand for it to be allocated elsewhere (there are huge capital demands from a number of infrastructure sectors globally).

- Australia has for a number of years been viewed by many international capital providers as an increasingly complex place to invest and with demising reward. This perception has intensified with the Government's commitment to the introduction of CPRS and RET.

- The demonstrated behaviour of Government in addressing the transactional cost for the generation sector associated with the introduction of CPRS and RET will be important. This will send a clear message to foreign investors about the degree of sovereign risk associated with investment in the Australian energy sector.

- The current global credit crisis has significantly reduced the international pool of capital that can be accessed for investment in Australia. Our domestic banks appear unlikely to have sufficient capital to support the level of investment required in the Australian energy sector.

- Australia is a price taker in global capital markets and if it is to be able to access capital for the energy sector the projects will need to represent attractive reward for the risk investors will need to accept. This may require that the price of energy rises above that necessary to recover both the cost of carbon and a risk-adjusted cost of capital. To be able to attract capital the cost of capital may need to rise above that implied by the risk of the investment.

- It may take five to seven years to repair the capital stock internationally and around the same time to repair the capital base of Australian banks following the credit crisis.

- International banks are retracting their balance sheets from application in Australia to focus on their home markets, thereby reducing access to the capital.

- Access to project financing will be extremely limited with the number of banks offering this form of finance in Australia reducing as a result of the credit crisis. Where project financing is available the banks are unlikely to accept any risk and the counterparties will need to be first class.

- The magnitude of the credit crisis will result in a step change to a more conservative approach to capital allocation which is likely to last a generation, reducing debt allocation and requiring additional equity to be committed to projects. In the absence of the additional equity, the projects will not proceed. Where the equity capital is available it will come at a higher price as a result.

- There will be an institutionalising of a more conservative approach to the provision of capital in response to the current credit crisis, which will transfer risk to equity and increase the risk premium attached to investment in general and for the energy sector.

- Governments are better placed when capital is severely constrained to access capital and at a reasonable price (see Figure 5.1), and may need to step in to provide capital where the private sector can't. Governments may also need to consider underwriting projects for a number years, or until the private sector can access capital at a more competitive price.

- Additional capital, beyond the capital required to meet the RET requirements, maintain existing service capacity and expand networks, will need to be accessed for the following:

    - It is understood that around $6.1 billion of energy sector project financed debt will need to be refinanced between 2009 and 2012 within a background of tight credit conditions and a significant number of general corporate refinancing placing pressure on debt providers given the quantum of debt needed. It is unlikely that the loans can be rearranged on equally favourable terms, therefore increasing the cost of funds for these entities, potentially reducing the level of debt in the capital structure and increasing a call on equity providers to inject additional capital.

    - Potential additional equity injection for projects where the assets may be impaired.

    - Renegotiation of bank guarantees for operations in the NEM. The introduction of CPRS and RET is likely to require that relevant market participants renegotiate bank guarantees for operations in the NEM. There is unlikely to be the same favourable terms offered by banks and there is potential for some existing participants to not be able to access a guarantee given the current credit conditions.

- Purchase of permits or abatement will require significant funding support. If there is a perfect pass-through of costs the issue can be minimised however the working capital requirement of some entities will need to increase to deal with this expenditure. If the private sector needs to access either debt or equity capital to fund this expenditure, the costs associated with it will be higher than would have been the case 12 months ago.

- Additional equity to reduce gearing of existing and future projects as debt providers reduce their exposure to risk.

- Additional equity to fund the transactions costs associated with existing generators transitioning from existing higher emitting plant to lower emitting plants. While the transition may have occurred over a longer time frame without the introduction of CPRS and RET, the bringing forward of this expenditure will place additional funding pressure on energy sector participants.

Allocation and reallocation of capital

Should Australia be competitive in attracting capital, the allocation of capital and reallocation of existing invested capital will play an important role in determining whether the investment needs of the sector can be met. Findings include:

- Existing investment in all segments of the Australian energy sector will face increased risk to some extent as a result of the introduction of CPRS and RET. The precise nature of the arrangements (e.g. carbon price trajectory, compensation for high emitters and how this is applied) will determine the degree of risk and how it is allocated. This will force capital providers to re-examine their allocation of capital to their investment and the cost of the capital they apply.

- Capital providers recognise that the energy sector segments have differing risk profiles (eg electricity has a different risk profile to that of gas networks) and expect that the introduction of CPRS and RET will potentially change the relative risk between sectors.

- Existing investors in the energy sector that will be materially disadvantaged by the introduction of CPRS and RET are likely to exit the sector all together – this will potentially direct some investment in renewable projects intended for the Australian energy sector to other countries.

- Capital providers, where they have an interest in investment in Australian infrastructure, consider the energy sector to be one of the least attractive areas for investment as a result of the additional risks imposed by CPRS and RET.

- Some international capital providers commented that they see potentially more attractive energy sector renewable investment opportunities outside Australia until the price of carbon is around $50/t or above in Australia.

- Some capital providers considered that the renewables sector would present more risk as a result of the introduction of CPRS and RET and as a result are likely to allocate their capital elsewhere.

- While regulated assets are considered to be the lowest risk of any segment, the potential of a reduced regulatory WACC and the potential underfunding of network augmentations create considerable uncertainty for some investors and may delay allocation of capital to the sector.

Cost of capital

There are a number of important factors affecting the cost of capital at present and into the future including: the perceptions of risk under CPRS and RET; the cost of funds and how this will change over the period till 2020; and the reweighing of risk and capital allocations between debt and equity providers. Findings include:

- The reward capital providers expect for the risk they accept in an investment has increased in general because of the credit crisis and in relation to investment in Australia as a result of CPRS and RET.

- A number of international investors in the Australian energy sector have already increased their hurdle rates as a result of the credit crisis.

- It is clear that the private sector's cost of funds has increased substantially as have some State Governments' regardless of debates over the theoretical calculation of cost of capital using tools such as CAPM and WACC.

- Debt costs have increased substantially in recent months with the differential between Commonwealth Government debt and BBB corporate debt (which would be equivalent to an electricity generator) now at 482.5 basis points as at 1 December 2008, resulting from a marked increase in the price put on risk and the lack of available capital.

- Debt providers have responded to reducing their exposure to risk by forcing equity providers to assume more of a project's risk. That is, a risk that can be reallocated away from a debt provider to an equity provider is likely to attract a higher price after reallocation.

- The credit crisis has resulted in capital providers being able to be very selective in the application of their limited capital, now requiring a higher return for the risk they bear. In other words, they expect their returns to increase to compensate for the same level of risk that they previously accepted for a lower return.

- CPRS and RET have increased risk, uncertainty and volatility, translating directly to risk for capital providers. These risks must be mitigated, managed and priced. Where the risk can't be removed completely it results in a higher risk premium being attached to the investments and therefore a higher return required to compensate for the risk.

ATTACHMENT C

Energy Supply Association of Australia

Proposed Minor Amendments to Section 40 of the Income Tax Assessment Act (1997) to recognise Geothermal Exploration Expenditure

Section 40-80 (Immediate deduction for decline in value of depreciating asset used for Exploration and Prospecting)

40-80(1)
The decline in value of a *depreciating asset you *hold is the asset's *cost if:

(a) you first use the asset for *exploration or prospecting for *minerals, ~~or~~ quarry materials or geothermal energy, obtainable by *mining operations; and

(b) when you first use the asset, you do not use it for:

(i) development drilling for *petroleum; or

(ii) operations in the course of working a mining property, quarrying property, ~~or~~ petroleum field or geothermal tenement; and

(c) you satisfy one or more of these subparagraphs at the asset's *start time:

(i) you carry on *mining operations;

(ii) it would be reasonable to conclude you proposed to carry on such operations;

(iii) you carry on a *business of, or a business that included, exploration or prospecting for minerals, ~~or~~ quarry materials or geothermal energy obtainable by such operations, and expenditure on the asset was necessarily incurred in carrying on that business.

Section 40-730(4)

"exploration or prospecting" includes:

(a) for mining in general, and quarrying:

(i) geological mapping, geophysical surveys, systematic search for areas containing *minerals (except *petroleum) or quarry materials, and search by drilling or other means for such minerals or materials within those areas; and

(ii) search for ore within, or near, an ore-body or search for quarry materials by drives, shafts, cross-cuts, winzes, rises and drilling; and

(b) for petroleum and geothermal energy mining:

(i) geological, geophysical and geochemical surveys; and
(ii) exploration drilling and appraisal drilling; and

(c) feasibility studies to evaluate the economic feasibility of mining minerals, ~~or~~ quarry materials or obtaining of geothermal energy once they have been discovered; and

(d) obtaining *mining, quarrying or prospecting information associated with the search for, and evaluation of, areas containing minerals, ~~or~~ quarry materials or geothermal energy.

Section 40-730(7)

Mining operations means:

(a) mining operations on a mining property for extracting *minerals (except *petroleum) from their natural site; or

(b) mining operations for the purpose of obtaining petroleum; ~~or~~

(c) mining operations for the purpose of obtaining geothermal energy; or

~~(c)~~ (d) quarrying operations on a quarrying property for extracting quarry materials from their natural site;

for the *purpose of producing assessable income.

Section 40-730(8)

Mining, quarrying or prospecting information is geological, geophysical or technical information that:

(a) relates to the presence, absence or extent of deposits of *minerals, ~~or~~ quarry materials or sources of geothermal energy in an area; or

(b) is likely to help in determining the presence, absence or extent of such deposits or sources
in an area.

40-860(1)

Mining capital expenditure is capital expenditure you incur:

(a) in carrying on *mining operations; or

(b) in preparing a site for those operations; or

(c) on buildings or other improvements necessary for you to carry on those operations; or

(d) in providing, or in contributing to the cost of providing:

(i) water, light or power for use on the site of those operations; or

(ii) access to, or communications with, the site of those operations; or

(e) on buildings for use directly in connection with operating or maintaining *plant that is primarily and principally for *treating *minerals, quarry materials or geothermal energy, that you obtain by carrying on such operations; or

(f) on buildings or other improvements for use directly in connection with storing minerals or quarry materials or to facilitate *minerals treatment of them (whether the storage happens before or after the treatment).

Section 995-1 definition for the purposes of section 40-30 and other

mining, quarrying or prospecting right is:

(a) an authority, licence, permit or right under an *Australian law to mine, quarry or prospect for minerals, *petroleum ~~or~~ quarry materials or geothermal energy; or

(b) a lease of land that allows the lessee to mine, quarry or prospect for minerals, petroleum or quarry materials or geothermal energy on the land; or

(c) an interest in such an authority, licence, permit, right or lease; or

(d) any rights that:

(i) are in respect of buildings or other improvements (including anything covered by the definition of ***housing and welfare***) that are on the land concerned or are used in connection with operations on it; and

(ii) are acquired with such an authority, licence, permit, right, lease or interest.

However, a right in respect of anything covered by the definition of ***housing and welfare*** in relation to a quarrying site is not a ***mining, quarrying or prospecting right***.