origin

18 November 2008

Australian Energy Market Commission
Level 5
201 Elizabeth Street
Sydney NSW 2000

By email: submissions@aemc.gov.au

RE: EMO 0001: Scoping Paper

Dear John,

Origin Energy Ltd (Origin) is pleased to provide a submission to the Australian Energy Market Commission's (AEMC) consultation "Review of Energy Market Frameworks in light of Climate Change Policies" (the Review). This is an important Review.

While we consider that existing market frameworks for both gas and electricity are generally well placed to manage the introduction of the Carbon Pollution Reduction Scheme (CPRS) and National Renewable Energy Target (RET), there are a number of areas of concern. Some of these have the potential to increase the risks to participants, and as a consequence require close attention from the AEMC. While we discuss these issues more fully in our attached responses to the specific questions posed in the Scoping Paper, we summarise our key concerns below.

Risk settings and interactions between gas and electricity markets

Currently gas fired generation (GFG) makes up only a small proportion of overall generation capacity in the National Electricity Market (NEM). The CPRS will drive a significant upsurge in the level of GFG seeking access to gas markets and pipeline capacity across the eastern seaboard. This will increase the inter-dependence of electricity and gas markets as demand for electricity will have a more direct impact on the demand for gas. GFG demand for gas is relatively unpredictable and dynamic and can respond much more quickly to changes in electricity prices than gas supply can respond to changing GFG demand. The CPRS is therefore likely to increase volatility of gas spot markets as well as increase stresses on the operational performance of pipelines. This is likely to have implications for congestion, cost allocation and reliability of supply.

It is critical in this environment that risk settings and price caps are consistent between gas and electricity markets to avoid as far as possible circumstances where greater returns available in one market compromises security and reliability of supply in another.

Investment in pipeline capacity and pipeline access

Pipeline investment in states other then Victoria is underpinned by long term bi-lateral contracts between pipeline owners and gas shippers. Shippers obtain firm transport rights to any capacity they fund (i.e. they have priority access to the capacity they need for transporting gas). Pipeline owners have incentives to make additional pipeline capacity available to those seeking it, and those participants requiring this capacity are willing to pay because they have exclusive rights to the additional capacity created. This combination of incentives should deliver the pipeline capacity GFG will need to operate in the NEM.

The Victorian principal transmission system (PTS) on the other hand is open access and investment in capacity, like in the NEM, can proceed through both regulated and private means. However, many participants are concerned that the regulatory process is conservative and insufficiently forward looking to meet the capacity needs of participants. Unfortunately private incentives for funding capacity investment in Victoria are also weak. While new privately funded capacity attracts AMDQ rights (a form of access right which provides some protection against congestion), non rights holders can use the additional capacity created by others without contributing to its cost. Creating additional pipeline capacity for one's competitors at no cost to them is unlikely to be conducive for encouraging private investment.

Origin considers that the lack of firm access rights in Victoria could delay or prevent much needed investment in transmission capacity, without which the network will become increasingly constrained and unable to support substantial increases in GFG. The development of firmer access rights is an important area for further reform in the Victorian gas market.

Congestion risk in the NEM

The CPRS and RET will encourage increasing quantities of renewable generation to connect to the network. Broadly speaking, the location of the best renewable resources is likely to mean that projects will tend to be in different areas to where generation has traditionally been located. This is likely to change the subsequent pattern and quantum of congestion. We are concerned that the regulated transmission investment process may not be sufficiently dynamic to keep pace with increasing and shifting patterns of congestion on the network or in many circumstances, be cost effective in resolving such congestion to the satisfaction of participants.

The materiality of this important issue will be investigated by three sets of modelling; commissioned by the Energy Supply Association of Australia, the National Generators Forum and Grid Australia. This modelling will usefully inform the extent of the problem. However, the complexity and uncertainty of accurately modelling congestion impacts some way into the future, leads us to lean towards supporting further development of alternative mechanisms for managing congestion, regardless of modelling outcomes. Relying purely on transmission investment to mitigate congestion under a CPRS may not provide sufficient certainty for participants in respect of the congestion risk they may face in the future under a CPRS.

Origin has previously indicated its support for selectively applied contract support and pricing arrangements and intends to further consider the potential of this approach and other approaches in more detail for further input over the course of the Review.

Investment in remote renewable generation

Meeting the objectives of climate change policies will require a substantial increase in renewable generation; and many of the best renewable resources, including wind, geothermal and solar thermal are located remote from the existing network. The long distances involved, and economies of scale of transmission, are likely to require large capacity high voltage lines for connection to these areas. However, extensions to the network that connect a generation participant, or group of generation participants, generally do not fall under the umbrella of the Regulatory Test, and as such lines would need to be funded by connecting parties themselves.

However, as Garnaut has noted[1], (and we discuss this issue in detail in Section 5 of the attachment), existing coordination problems and cost allocation arrangements impose high upfront costs and commercial risks on the first connecting parties to trigger the need for new large connection assets. This may discourage investment in remote generation because no party will want to be the 'first mover'.

This could mean that climate change policy targets are either not met, or met at much higher costs to consumers than necessary. Origin considers this to be a key weakness in the existing transmission regulatory arrangements, and we present some thoughts on how this may be resolved in Section 5 of the attachment.

Allocating costs for inter-regional investments under the Regulatory Test

A further important area of reform is the cost allocation arrangements for large transmission investment projects which pass the Regulatory Test (they provide net benefits of the market). Some of these projects may have benefits spread across the NEM, but the actual transmission costs fall within one or two regions (because that is where the resource is located). This is likely to become an issue of increasing importance under a CPRS and RET, which will over time require access to more remote renewable resources. To have one state's consumers bear the majority of transmission costs while the benefits of the investment are spread across other states is likely to be politically unacceptable. This may cause delay to important transmission projects necessary for meeting climate change policy objectives. Therefore, the development of an appropriate inter-regional transmission charging mechanism will be important going forward.

Carbon-pass through

The ability for retailers to pass through carbon costs will be fundamental to ensuring the reliability and security of supply under a CPRS.

It will be very difficult to predict how future wholesale prices will be impacted by the CPRS in its early phases, as there will be no history of prices on which to base such an assessment. Establishing the appropriate cost of carbon in contracts, and retail tariffs, will therefore be a difficult exercise in this uncertain environment. This uncertainty is reflected in the current lack of forward contracting taking place for supply beyond 2010.

The anticipated complexity of estimating carbon costs for inclusion in retail tariffs lends strong weight to arguments for fully deregulating retail tariffs post 2010. If price regulation continues without the certainty of carbon cost pass through, retailers could find it increasingly difficult to contract for supply from potential new generators which will impact generation investment.

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[1] Ross Garnaut, *The Climate Change Review, Final Report*, Cambridge University Press, 2008, chapter 19

In the absence of deregulation however, the question then arises as to what is the best method for estimating the cost of carbon in the short to medium term for input into regulated retail tariffs for electricity and gas (where applicable). Origin strongly encourages the Ministerial Council on Energy to commit to establishing a single national framework for assessing the relevant costs of the CPRS (possibly under the auspices of the Australian Energy Regulator) and direct the AEMC to develop a common methodology for determining the cost of carbon in retail tariffs. A common methodology is critical as this would ensure that the competitive landscape facing retailers remain neutral across jurisdictions and that regulatory risks do not vary by state. The prospect of different jurisdictions adopting different approaches to the pass through of CPRS costs is of key concern to Origin.

This process should commence immediately, as it is essential that the elements of the framework are in place and agreed by jurisdictional Ministers prior to the end of the current retail price determination periods, most of which are up for review around the time of the commencement of the CPRS, or shortly thereafter.

Impacts of CPRS and RET on reliability of supply

A fundamental concern of the AEMC Review is the extent to which the CPRS and RET will undermine supply reliability in the NEM. While Origin considers these concerns are overplayed to some extent (as we discuss in section 2 of the attachment), it is important that some of the issues which have led to the climate of uncertainty in the contract market are addressed soon so as to minimise potential impacts on generation investment going forward.

Some of these issues may prove to be transitional, such as the uncertainty surrounding the finer details of the design of the CPRS and RET. However uncertainty surrounding carbon price pass through in the retail market and increasing doubts regarding the level of firm access to the network have the potential to seriously undermine investor confidence in the market. It is therefore imperative that these issues are dealt with as part of this Review.

Please do hesitate to contact Tim O' Grady on 02 8345 5250 or Con van Kemenade on 02 8345 5278 in the first instance if you have any questions on these matters.

Yours sincerely,

Carl McCamish
Executive General Manager
Corporate Development and Communications

Questions and Answers

1 Convergence of gas and electricity markets

Summary of key points

- Development of spot markets in SA and NSW and Bulletin Board is likely to enhance flexibility and transparency in the gas market, helping to facilitate trade in gas
- As the proportion of gas fired generation increases, gas and electricity markets will become inextricably linked.
- Congestion should be included in the market price in Victoria
- There needs to be consistency in risk setting in both gas and electricity markets.
- Private incentives to invest in pipeline infrastructure in Victoria need to be strengthened to complement the regulatory framework.

1.1 How capable are the existing gas markets of handling the consequences of a large increase in the number of gas-fired power stations and their changing fuel requirements?

1.2 What areas of difference between gas and electricity markets might be cause for concern and how material might the impacts of such differences be?

Interactions between gas and electricity markets

Victoria has a spot market for gas, and a spot market i.e. the short term trading market (STTM) is set to be introduced in SA and NSW in 2010, at around the same time as the commencement of the Carbon Pollution Reduction Scheme (CPRS). It as anticipated that this will assist in creating a transparent daily market signal for the value of gas. A Bulletin Board has also recently been introduced, which is intended to increase the transparency of information in the gas market. These developments should help facilitate trade and the delivery of more flexible forms of gas supply to market, allowing gas fired generation (GFG) participants to make more efficient trade-offs between gas and electricity markets.

The quantity of all types of GFG entering the National Electricity Market (NEM), including peaking, intermediate and baseload will increase substantially under the CPRS and Renewable Energy Target (RET). As GFG increases its proportion of overall generation capacity, gas and electricity markets will become more inextricably linked. For example, tightness in the supply-demand balance in the NEM is likely to be reflected in the gas market as GFG demand more gas for electricity generation. It is important to note, however, that GFG can adjust its output much more quickly to respond to changes in electricity demand than gas supply can respond to changes in GFG demand for gas. Consequently, as the quantity of GFG increases in gas markets the variability of electricity prices during the day will impose an increasing level of volatility in gas markets and operational stresses on the pipeline infrastructure.

In Victoria this is likely to increase the occurrence of "surprise congestion uplift", which already forms by far the largest component of overall congestion there[1]. A key problem in the Victorian market is that congestion is not included in the market price, but is calculated and settled separately, which leads to complex, opaque and at times inconsistent, cost allocation amongst participants. These issues are likely to become more significant as an increasing volume of gas connects to the principal transmission system (PTS) and elsewhere in the south eastern gas markets.

[1] This type of congestion is due to under-forecasts of supply requirements by shippers, requiring more expensive gas supply, LNG, to be constrained on

Origin considers that congestion should be included in the market price in Victoria, as this increases the accuracy, transparency and information signalling properties of the gas market price. This in turn improves prospects for efficient consumption, demand side management and investment in storage and pipeline capacity (both of which may be vitally important for supporting future GFG), which will be critical to meeting the upsurge in gas demand required for GFG. This approach to pricing would also be more consistent with proposed design directions for new gas spot markets in SA and NSW.

Risk settings and security of supply

Currently when there is shortage of supply in gas markets, GFG tend to be among the first to be curtailed. GFG can respond quickly, and because they are mostly peaking generation they tend to have interruptible contracts[2]. In addition, owners of peaking capacity are typically retailers, who prefer to reduce their GFG before constraining their gas customers. To date this has been a relatively acceptable state of affairs given the low quantity of GFG in the market. Curtailment of GFG will become more problematic as its volume grows over time, and more baseload plane enters the NEM. Large volumes of GFG quickly ramping up gas demand could create shortages in the gas market, or create operational stresses on pipeline infrastructure compromising its capacity to deliver gas to customers. This is likely to increase the frequency of curtailment of GFG which may impose significant opportunity costs on participants; particularly for independent generation participants (vertically integrated participants will obtain the benefit of being able to supply gas to its end users).

Apart from financial implications for generation participants, curtailment of gas supply to GFG may also impact the reliability of supply in the electricity market. NEMMCO relies on GFG to manage supply disruptions because of its quick ramping capability. While an integrated Australian Energy Market Operator (AEMO) will be well placed to manage these sorts of trade-offs, it is important that existing security and reliability mechanisms operating across electricity and gas are consistent and that these do not distort economic incentives for market participants. Take the example of the current review of the value of lost load (VoLL) in the Victorian gas market. Consultants commissioned by VENCorp have recommended that it be more than halved from its current level of $800/Gj. This value is approximately equivalent to a $10,000 VoLL (when converted for heat rates) in the NEM. The NEM VoLL is also under review, with the Reliability Panel recommending that it be increased to $12, 500/MWh from 2010.

To the extent that outcomes of these reviews lead to price caps that vary significantly between markets this has the potential to create incentives for making supply shortages worse. When demand is tight in both gas and electricity markets and prices are near their caps, the incentive for GFG could well be to maximise their consumption of gas for electricity generation, thus making a gas shortage worse. While this would be mitigated by gas customers (mostly GFG in the first instance) being ‘constrained off’, this is a hardly a satisfactory outcome for generation participants who will receive no compensation for doing so.

The ability of GFG to sell contracted gas directly into the Victorian gas market at a price which approximates its opportunity cost in the electricity market is therefore important in ensuring that market mechanisms support reliability of supply outcomes and at the same time encourages investment in GFG generation capacity. A sufficient level of VoLL that recognises the opportunity costs of gas will also be vital in encourage building the storage and pipeline capacity required to sustain large increases in GFG without compromising the integrity of gas markets.

[2] Peaking generators tend not to reserve excess capacity, because they generate so infrequently, some prefer to rely instead on liquid fuel, which would still be profitable given high electricity VoLL.

With its recently added responsibility for gas market rule changes, we consider that the AEMC is well placed to undertake a review into the consistency of risk settings in gas and electricity markets.

Transmission investment in the Victorian gas market

Pipeline investment in states other then Victoria is underpinned by long term bi-lateral contracts between pipeline owners and gas shippers. Shippers obtain firm transport rights to any capacity they fund (i.e. they have priority access to the capacity they need for transporting gas). Such firm access to transportation capacity will be maintained even with the introduction of spot balancing markets in these states[3].

Victoria on the other hand operates an open access network where rights to transmission capacity are not required for transporting gas. Similar to the NEM, investment in transmission capacity can occur both through regulated and private means. The regulatory approach requires VENCorp to undertake a Regulatory Test (i.e. a cost-benefit analysis), to determine whether a particular investment confers net benefits to the market, (for e.g. a project could increase competition between different supply sources, allowing new cheaper sources of gas to enter the market, or enhance the reliability of supply). Where a particular project is deemed to pass the regulatory test costs can then be recovered from consumers.

The regulatory test has only recently been introduced in Victoria and is as yet to be fully tested. Unlike the NEM, there is no obligation on either VENCorp or GasNet to invest to maintain reliability standards. This weakens the incentive to pursue investments because there is essentially no accountability for either party for the consequences of investment. We note for example that in the NEM, where there is a strong reliability requirement, very little transmission investment has been undertaken for anything other than meeting reliability standards.

In one sense this demonstrates the power of having a mandatory requirement. On the other hand, this is also indicative of some key difficulties of a regulatory approach to investment. Transmission investment creates winners and losers, and the regulatory test process is as a result a complex modelling process requiring broad stakeholder involvement and agreement. Like any modelling it is dependent on assumptions which will be open to interpretation and debate. The test is therefore conservative; it requires a proposal to be the best among a number of alternative proposals and across a range of possible future scenarios. Further, because it is difficult and potentially controversial to ascribe more weight to one future scenario over another it takes no account of the potential for some scenarios to be more probable than others (scenarios tend to be equally weighted). This leads to a "lowest common denominator" approach to investment, which minimises the potential for dispute and for consumers to face "excessive costs" associated with stranded investments.

Largely as a consequence of these issues, which have more relevance in gas due to the absence of a mandatory investment requirement, a key concern for participants that operate in the Victorian market is whether the regulatory approach to investment is responsive and dynamic enough to support the substantial increase in GFG expected under a CPRS. Over the past two winters capacity has been very tight in Victoria, which already points to investment not keeping pace with demand. For this reason, Origin considers it of critical importance that private incentives for investing in pipeline capacity are strengthened so that transmission investment arrangements as a whole can be more responsive to meeting the challenges of climate change.

Origin and others have been keen to invest in the PTS to increase access to market for both its gas market customers and GFG but the regulatory framework provides little support for this. While new privately funded capacity attracts AMDQ rights (a form of access right

[3] This will be achieved by ensuring that non firm shippers who are dispatched in the spot market are required to provide capacity payments to firm shippers who are not dispatched. See STTM stage 1 detailed market design, forthcoming VENCorp website.

which provides some protection against network congestion), non rights holders can use the additional capacity created by others without contributing to its cost. Creating additional pipeline capacity for one's competitors at no cost to them is unlikely to be conducive for encouraging private investment. And no rights at all are available for expanding capacity to increase exports out of Victoria. The latter identifies a clear boundary between regulatory arrangements for gas markets in different states which may undermine moves towards a more integrated national gas market.

Origin considers that the lack of firm access rights in Victoria could delay or prevent much needed investment in transmission capacity, without which the network will become increasingly constrained and unable to support substantial increases in GFG. The development of firmer access rights is a key area for further reform in the Victorian gas market.

2. Generation capacity in the short-term

Summary of key points

- The single largest barrier to investment is uncertainty surrounding cost pass through in the retail market.
- Continued uncertainty surrounding the finer details of the climate change policies is likely to delay investment
- Uncertainty regarding access to the network is expected to become an increasingly important issue as more generators enter the market
- A significant shortfall in generation capacity is not anticipated in the short term, but impediments to investment must be addressed to avoid shortfalls in the medium to long term.

2.1 What are the practical constraints limiting investment responses by the market?

2.2 How material are these constraints, and are they transitional or enduring?

Uncertainty surrounding costs pass through in the retail market

Origin considers that the regulatory uncertainty surrounding cost pass through in the retail market, (particularly with the introduction of the CPRS), is the single largest barrier to investment and the future security of electricity supply. The current jurisdictional based price regulation mechanisms creates uncertainty as to whether retailers will be able to pass on the costs associated with the CPRS to customers. If price regulation continues without the certainty of the carbon cost pass through, retailers could find it increasingly difficult to contract for supply from potential new generators. This is likely to constrain investment by making it harder for new generators to enter the market.

The removal of price regulation or at a minimum the development of a consistent framework for assessing CPRS costs and the mechanisms for the full pass through of these costs is needed. This issue will be discussed in greater detail later in this submission.

Uncertainty surrounding access to the network

It is anticipated that the RET and CPRS will result in more renewable generators (particularly intermittent generators) entering the market. Given the location of the renewable sources, these policies also have the potential to change the location of future generation in the NEM away from where it has been located traditionally. This will have implications for the configuration of the network, which along with the increased volume of intermittent generation could result in more network congestion. An increased level of congestion creates uncertainty regarding the level of firm access available to all generators, as congestion can often result in the 'constraining off' of some generators. Increasing uncertainty regarding the lack of firm access to the network has the potential to impact negatively on investment by leading to higher discount rates and the need for higher rates of return to satisfy potential investors.

The materiality of this constraint and whether it proves enduring is dependent on the speed and effectiveness of the policy response aimed at addressing the required changes to the network to facilitate the CPRS and RET.

Uncertainty and climate change policy design

Uncertainty surrounding the Government's climate change policies has led to scepticism amongst investors in the electricity market. The virtual non-existence of long term contracts beyond 2010 and the relatively low level of reserve generation indicate that businesses have opted to delay investment until the future direction of the energy market becomes clearer.

Notwithstanding that this Review's primary purpose is not to assess the merits of the policy design of the CPRS or RET, Origin considers that some of the key design features of the CPRS in particular, is likely to further impede investment decisions in the market.

The Green Paper states that the Government will announce a medium term national target range for 2020 in the White Paper at the end of the year. The setting of a fixed target now, is preferable as too broad a range is likely to exacerbate the uncertainty in the market. At the very least a decision rule similar to that proposed by Garnaut would be useful where a 'maximum effort' target would be adopted if an international agreement is reached and a 'minimum effort' target (that Australia would be willing to commit to) in the absence of a global agreement.

The scheme caps are to be set and announced for a minimum period of five years in advance. Again, industry would prefer a longer period as five years is unlikely to provide enough comfort for investors looking to invest in long-lived assets. The timing of the announcement of the scheme caps is also important, with the Government planning to announce in the White Paper an approach to setting caps for the period 2010-11 to 2014-15. The finalised caps for the first five years of the scheme will not be set until early 2010. We see no reason why a firm scheme cap for rest of the Kyoto commitment period cannot be announced by the end of year, followed by firm caps to 2020 following the international negotiations.

The above proposals do not provide sufficient clarity to inform investment decisions. The longer the level of uncertainty in the market persists, the greater the delay in investments and the more likely any future shortfall in electricity supply.

In regard to the RET, the Government has yet to indicate its preferred trajectory. This is important as the trajectory will shed light on the required speed of investment needed to meet the target.

2.3 How material is the likelihood of a need for large scale intervention by system operators? How likely is it that this will be ineffective or inefficient?

Origin considers that based on our modelling and other factors discussed below; it is unlikely that there will be a need for large scale intervention by systems operators to address shortfalls in capacity in the short term (i.e. by 2015). It is important, however, that the impediments to investment discussed above, are urgently addressed, to ensure that there are no shortfalls in the medium to long term.

Baseload capacity

There has bee some concern that the CPRS in particular could lead to a deficit in supply in the short term if it makes it so expensive for coal generators to operate that they are forced to run less frequently or exit the market prematurely, or if it results in a change in the merit order of dispatch which forces coal plant to behave more flexibly – possibly stretching their technical operational limits.

We do not anticipate a significant withdrawal of coal plant from the market in the short term as they will be able to pass through the higher costs associated with the carbon price, as we discuss briefly below.

In the NEM, coal provides approximately 70% of capacity and around 85% of energy – all of which is required by retailers to meet their existing contract requirements. Given the lead times for new entry, there will not be sufficient alternative generation from lower emissions generators in the short term to erode the pricing power of coal fired generators in the spot market, or compete with coal plants in the provision of contracts to generators. We expect therefore that coal generators will be able to pass on the higher prices as a result of the CPRS, which should provide an incentive for them to remain in the market[4].

While it is acknowledged that asset values may be reduced for high emissions generators under a CPRS, this is unlikely to affect reliability or lead to sudden and disorderly exit from the market. Many high emissions generators are financially backed by state governments and thus their credit ratings may be little affected. For those whose credit ratings fall precipitously they will simply become takeover targets for other companies or the debt providers themselves, who will have every incentive to run them because capital costs for many of the generators will already have been recovered, or in any case are sunk. This means that provided wholesale prices exceed the variable fuel costs of the generators the incentive will be to run them, regardless of their capital or ownership structure.

Over the longer term if wholesale prices fall below marginal cost, forcing closure of more expensive plant, the reduction in supply should lift wholesale prices and subsequent revenues obtainable for other generators, as well as encouraging new entry. There is little reason to suspect that normal market mechanism of entry and exit should break down under a CPRS provided costs can be appropriately be passed through to end users. It is in effect retailers who will underpin generation investment by entering into forward hedge contracts with generators to supply their customers. However, retailers will only enter into contracts with generators, and new customers for that matter, if they can be assured of passing through their wholesale energy purchase costs.

It should also be noted that the Government has assured a relatively ‘soft’ start to the CPRS to ensure a smooth transition to a low carbon economy. This means that the carbon price in the early years is unlikely to be high enough to effect a change in the merit order of dispatch which minimises the risk of coal plants being forced to generate more flexibly – beyond their technical capabilities.

Demand management

Efforts to address the demand side will also assist in loosening the demand supply balance. These include:

- The roll-out of smart meters
- The Acme's review into demand side participation in the national electricity market (NEM); and
- The Council of Australian Government’s (COAG) intention to work towards the implementation of a cohesive national approach to energy efficiency

[4] See for example, Roam Consulting submission to the federal government's consultation on the Green Paper

- Higher electricity prices that capture the cost of carbon in particular will provide a strong incentive for enhanced demand side response

3 Investing to meet reliability standards with increased use of renewables

Summary of key points

- Large increase in intermittent generation will have to be supplemented by investment in peaking plant and augmentations to the transmission network.
- Proactive approach to managing reliability will be important going forward.
- Appropriate inter-regional transmission charging mechanism needs to be developed.

3.1 How material is the risk of a reduction in reliability if there is a major increase in the level and proportion of intermittent generation?

3.2 What responses are likely to be most efficient in maintaining reliability?

The RET, in particular, will lead to a significant increase in the volume of intermittent generation (chiefly wind) entering the electricity market. Wind farms by their nature cannot be relied upon to ramp up their generation in response to increases in demand, and thus any increase in the level of wind generation will have to be supplemented by increases in 'back up' capacity (most likely gas fired peaking plant), to ensure that reliability is maintained.

The challenge is to provide enough incentives to encourage investment in peaking generation given the relatively limited opportunities these plants have to recover fixed costs. The proposed increase in VoLL from $10,000 to $12,500 should help stimulate investment in peaking plant, but it is not yet known with the certainty how effective this will be given the large increase in peaking generation that will be required.

The large increase in intermittent generation is also likely to require augmentation in the transmission network, including increased interconnection. There is a risk however of new generation capacity connecting more quickly than the efficient downstream augmentation of the network can occur, particularly given the lead time for new transmission investment. This could have serious implications for reliability if the increased volume of intermittent generation leads to new and enduring areas of congestion in the network, which are unable to be addressed in time by augmentations to the network. Congestion often leads to the 'constraining off' of some generators, which limits supply and could potentially make it more difficult to meet the reliability standard.

There is therefore a genuine risk of a reduction in reliability if there is not a corresponding increase in peaking generation as well augmentation of the transmission network to address congestion and to allow for more interconnection amongst regions.

Managing future reliability

A proactive approach in managing reliability will be important going forward. The Reliability Panel's (Panel) proposed incremental increase in VoLL from $10,000 to $12,500 is likely to strengthen the investment signal by providing a greater incentive for Market Participants to enter contracts.

Additionally, the proposed two-yearly review of the reliability settings, including VoLL, will further facilitate this proactive approach by providing an opportunity to alter the reliability settings in response to changes in the market.

As discussed above there might also be a need for augmentations to transmission network such as upgrades to the interconnectors, to help manage any increase in congestion. An appropriate inter-regional transmission charging mechanism (IRTCM) will be required to ensure that the cost of any augmentation is appropriately apportioned. This will help in ensuring that transmission projects that offer inter-regional benefits get built.

The AEMC outlined four options for an IRTCM in its National Transmission Planner (NTP) Draft Report. It is important that these options are further developed for consideration as part of this Review.

Importantly there will also be a need for investment in the augmentation of secondary transmission elements, which have the capability of constraining primary transmission elements (interconnectors). An example of this is in South Australia where constraints on transmission lines in the South East (partly due to increased wind generation) can lead to a downgrade in the capability of the Heywood interconnector. Origin welcomes the intent of the new National Transmission Planner (NTP) to also focus on these secondary transmission elements and not just the national transmission flow paths (major corridors of power transfer).

4 Operating the system with increased intermittent generation

Summary of key points

- Large increase in intermittent generation will require greater use of ancillary services to ensure system security and stability is maintained.
- System operator has sufficient tools to deal with network security and stability issues.
- There is a risk for the need for large scale intervention if transmission investment does not keep pace with any increase in congestion.

4.1 How material are the challenges to system operations following a major increase in intermittent generation?

4.2 Are the existing tools available to system operators sufficient, and if not, why?

The anticipated increase in intermittent generation (chiefly wind) will make system operation increasing more challenging with serious implications for network stability and security. With a large volume of wind generation in the system, unexpected changes in the output from wind farms is likely to impact on frequency and voltage control. This will require greater use of frequency control ancillary services (FCAS) and network control ancillary services (NCAS) to manage frequency and voltage respectively.

Origin is of the view that NEMMCO has sufficient tools at its disposal to deal with the challenges to system security posed by the increased entry of intermittent generation in the market.

All new wind farms will have to be classified as semi-scheduled generators under the new semi-dispatch Rule, which means that they will be incorporated into central dispatch at times of a binding constraint. This will give the market operator greater control over the output of intermittent generators, enabling better management of system security.

The availability of the new Australian Wind Energy Forecasting System (AWEFS) will enable NEMMCO to get more accurate forecasts of wind power and assist in the preparation of the unconstrained intermittent generation forecast (UIGF), under the new semi-dispatch

arrangements. The UIGF is the equivalent forecast of electrical power output from a generating unit based on the forecast amount of energy available for conversion into electrical power. The AWEFS and the UIGF should enable NEMMCO to better manage the power system, provided that the forecasts provide a high degree of accuracy.
Semi-Scheduled Generators will be responsible for the full cost of the regulation FCAS that they create the need for. This should provide an incentive for them to minimise their contribution to frequency deviation through measures such as investing in more advanced active power control technology, and providing the most accurate information available for use by the UIGF.

Increased costs (i.e. FCAS costs, risk of being 'constrained off') should also provide incentives for intermittent generators to locate in areas that make it less challenging for the market operator to manage the system. The problem with this, however, is that like existing high emissions generators, renewable generators are somewhat constrained to locate near their fuel source, which leads to concentrations of renewable generators in certain areas. If however, the costs of locating at first tier wind sites becomes too high due to greater network congestion and the corresponding increase in the likelihood of being 'constrained off' as well as greater FCAS costs; it might become more economical for prospective wind generators to locate at second tier sites.

Semi-Scheduled Generators are also required to have the capability to respond to voltage and reactive power instructions from NEMMCO, in accordance with the requirements in the technical standards.

4.3 How material is the risk of large scale intervention by system operators and why might such actions be ineffective or inefficient?

4.4 How material are the risks associated with the behaviour of existing generators, and why?

There is a real risk of both intermittent and scheduled generators being 'constrained off' by the market operator as a means of maintaining system security and reliability, particularly where new areas of congestion occur.

The above actions are likely to prove effective with dealing with any system operations issues, but will not necessarily be efficient as it could result in the 'constraining off' of cheaper sources of generation, which is contrary to the national electricity objective of satisfying demand at least cost. Moreover, to extent that transmission investment does not keep pace with increased congestion brought about by the large volumes of renewable generation connecting to the network, there will be increased opportunities for the exercise of market power in constrained regions, which can distort market and pricing outcomes.

There might also be perverse incentives for some generators to locate on the 'wrong side' of a constraint to take advantage of market power opportunities as other generators are 'constrained off'.

5 Connecting new generators to energy networks

Summary of key points

- The existing economic incentives in the current regulatory arrangements appear to encourage efficient trade-offs between gas and electricity transmission investment.
- Existing arrangements for connection of generators will discourage investment in remote generation
- Incentives for private investors to fund large transmission projects need to be

strengthened.

- A variant of the California solution mentioned in the Garnaut report could work here.

5.1 How material are the risks of decision-making being “skewed” because of differences in connection regimes between gas and electricity, and why?

Investors in generation capacity will typically look at a wide range of factors in deciding where to locate. A key decision factor is comparing the costs and risks of transporting fuel versus transporting the electricity itself. In deciding where to locate, GFG will need to compare the costs and associated transport risks of locating close to the gas supply source and potentially funding electricity transmission to get the product to market, versus locating closer to the market and funding more gas transmission to get the fuel to the generator. The regulatory arrangements for both gas and electricity (transmission pricing and access) should encourage this trade-off to be made in an efficient manner so that over time, the optimal combination of electricity and gas infrastructure is developed to meet market demand.

Gas pipeline capital costs are typically half that of electricity transmission, and generally also offer firmer access to transportation capacity. So all other things equal, the incentive for an investor in GFG is to locate closer to market where electricity is to be supplied and build more gas pipeline infrastructure to transport the fuel.

It is important to note, however, that there are circumstances where a generator who chooses to locate closer to the fuel source may not bear the full costs of the electricity transmission required to connect the generator to the network. This occurs if there are wider benefits to the market as a whole associated with that particular locational decision (as assessed through the regulatory test consultation process). For example because of the networked nature of electricity transmission (as compared to gas infrastructure), the expansion of transmission to connect the generator may increase the level of geographic competition between different generators, inter-regional reliability through capacity sharing, or defer the building of more expensive generation capacity elsewhere. Where the predicted benefits of this (in avoided costs or lower wholesale prices) outweigh the costs of the transmission itself then the costs can be recovered from consumers and the connecting party will not have to pay.

The regulatory recovery of transmission costs from consumers is not available for gas transmission in states other than Victoria. However, given that gas pipeline network in these states tends to be point-to-point rather than networked; expansion of pipeline capacity in these circumstances is unlikely to confer the same sorts of "public good" benefits as electricity transmission.

The existing economic incentives in the current regulatory arrangement therefore appear to be broadly appropriate for encouraging efficient trade-off's to be made between gas transmission and electricity transmission, despite the differing access arrangements.

More problematic would be the circumstance where gas transmission was considerably more expensive than electricity transmission but the opportunity for "firmer access" in gas relative to transmission skewed decisions toward pipeline investment over transmission investment. This would indicate that differences in regulatory arrangements between gas and electricity were potentially distorting efficient market outcomes in transmission investment.

5.2 How large is the coordination problem for new connections?

5.3 Are the rules for allocating costs and risks for new connections a barrier to entry, and why?

Lack of private incentives for funding transmission

Currently negotiations for new connections are done bi-laterally between the Transmission Network Service Provider (TNSP) and each new participant connecting. Confidentiality prevents each connecting party from knowing whether other connection applications are in train with the TNSP. To date an incremental and sequential approach to connection has not been a serious issue, due to new generation generally locating close to the existing network. It has the potential to become much more problematic however, as increasingly remote renewable resources will need to be accessed under the CPRS and RET.

To meet the climate objectives of CPRS and RET will require a substantial increase in renewable generation, and many of the best renewable resources, including wind, geothermal and thermal solar are located remote from the existing network. The long distances involved, and economies of scale of transmission, are likely to require large capacity high voltage lines for connection to these areas. However, extensions to the network that connect a generation participant, or group of generation participants, generally do not fall under the umbrella of the regulatory test (as only the network is considered to confer shared benefits to the market as a whole), and so such lines would need to be funded by connecting parties themselves.

As was identified in the Garnaut Report[5], however, the existing NER may discourage private funding of large connection or transmission assets. The first party triggering the need for the transmission asset will be required to pay its full costs asset up front. Whilst the costs of the line are reimbursed to the original connecting party over time as other parties connect, the 'first mover' bears the risk that others may not turn up. The incentive will therefore be to wait for others to be the first to trigger the investment; clearly however, if everybody waits then the transmission line will not get built. While participants could seek out one another and collectively fund the line up front, this will involve search and negotiation costs, and ignores the fact that new entrants are likely to enter the market at different times.

A further disincentive for private funding of large transmission assets is the fact that paying for the line does not guarantee access to market, which is determined through competitive dispatch offers and the extent to which congestion in the deeper network itself prevents dispatch of remotely located generators. While participants who fund the connection asset could also fund additional deeper network re-enforcement to accommodate the additional energy transferred from the connection asset, this would not confer any additional firm rights over the new capacity created (it does not prevent other new entrants from using it). There is currently no compensation for being 'constrained off', so access to the network, regardless of whether transmission is funded by participants or by consumers, will be non-firm.

The above issues create a classic prisoner's dilemma, where it is in the interests of market as a whole to have generation built remote from the network to access renewable resources, but the incentive for individual participants is to wait for others to do so first. This may either delay or prevent much needed renewable generation from being built in a timely fashion. The implication of this is that either climate change objects are not met or they are met at much higher costs than necessary.

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[5] Ross Garnaut, *The Climate Change Review, Final Report*, Cambridge University Press, 2008, chapter 19

These problems will be of particularly relevance for renewable participants, who tend to be of small size. Renewable resources located in remote areas may contain thousands of MWs of renewable potential, but each connecting party may be quite small in comparison (most wind generation participants are rarely over 100 MW). Small Individual participants are unlikely to be willing or able to pay the substantial up front costs of a large capacity line access to which may well be available to others down the track.

Solving the incentives and coordination problem

As discussed above, the incentives for private funding of large connection assets is weakened by "first mover" problems and the inability of the funding parties to capture the full benefits of the deeper reinforcements required to support the connection to the network. Private funding of transmission capacity, whether connection assets or deeper reinforcement, may provide inadvertent support to competitors in gaining access to the market as they connect subsequently. This will act as a barrier to entry for renewable generation.

This issue could be addressed in two, possibly complementary, ways. The first is to allow for firmer financial access to transmission that is privately funded. For example, some form of access or transmission right could be allocated with privately funded transmission capacity. Such a right would then allow for compensation to be paid to participants in the event they are constrained off. The key benefit of this type of approach is that no regulatory test or centralised decision process would need to be undertaken for progressing investments. Participants could simply evaluate the information provided by the National Transmission Planner (NTP) on where and when to invest, and then go ahead and do so. Such an approach would however be complex to implement and would most likely require Transmission companies to play a significant role in assessing, collecting and making compensation payments.

A second approach, identified in the Garnaut report, introduces a centralised coordination process for assessing private interest as well as a new cost allocation process for large connection assets. It therefore contains elements of a regulatory approach while enhancing private investment incentives, which may be more consistent with and incremental to existing arrangements. It is a variation of an approach originally conceived in California and directly addresses the coordination and economies of scale issues of transmission.

- The NTP would identify and rank areas of high potential for renewable resources; TNSPs and participants could use this information to undertake a process for assessing and coordinating participant interest for future connection in these areas.

- A number of different areas of potential could be identified; A "high level" economic assessment by the NTP and TNSPs combined with assessed participant interest (this could be financial commitment or planning consents etc, or possibly even forward sale of access contracts) would determine the location and optimal size of the line, taking into account of economies of scale, deeper reinforcement and stranding risk.

- The TNSP could seek AER approval for up front funding for the balance required to build the line (a regulatory allowance could be sought in the same way as for a "contingent project").

- The residual costs of the line are repaid to TNSPs over time as each new generator connects. However, consumers bear some of the risk of asset stranding relating to that proportion of the line for which no prior participant commitment is made.

- Each generator pays only for the proportionate capacity of the transmission line which he utilises to transfer his generation, which is consistent with a shallow connection policy. If the line becomes part of the shared network over time (for example if loads connect along the line, or additional transmission is built to connect the line to other parts of the network), then users should contribute to the costs.

- Initial funding could be provided from Infrastructure fund, as suggested Garnaut suggests, as this would avoid the need for increases in transmission charges.

This approach would have the following benefits:

- Improves incentives for generation investment in remote resources.

- Provides a mechanism for TNSPs to obtain full cost recovery for the transmission investment without unduly burdening the development of renewable generation (wind, solar thermal, geothermal in particular).

- Reduces the costs and risks to renewable participants associated with transmission investment and increases the potential that it is developed in a timely (more strategic) manner. In particular it increases the likelihood that transmission will be available when participants initiate a transmission connection request and ensures they do not have to bear the full cost of those facilities up front.

- While electricity customers will bear some of the risk of transmission asset stranding, they benefit from the unlocking of remote renewable generation resources through which climate change policies can be advanced, and lower costs associated with economies of scale (the public good benefits of transmission). This should lower the overall costs of climate change to consumers.

- Could be incorporated readily into existing arrangements

While undoubtedly needing further review and refinement Origin considers this kind of approach, or some variation of it, could form a very useful complement to existing transmission investment arrangements and would sit comfortably with the new national transmission planning framework.

6 Augmenting networks and managing congestion

Summary of key points

- Significant increase in renewables including intermittent generation connecting to the network may increase and shift existing patterns of congestion.
- Increased congestion risk combined with inability to secure firm access could inhibit investment.
- Private incentives to invest in gas transmission are weaker in Victoria than in other states.
- Mechanism needs to be developed for the interregional sharing of costs of significant transmission projects which pass the regulatory test

6.1 How material are the potential increases in the costs of managing congestion, and why?

6.2 How material are the risks associated with continuing with an “open access” regime in the NEM?

Origin notes that the transmission investment framework has recently been strengthened, with a more streamlined Regulatory Investment Test for transmission providing stronger incentives for TNSPs to seek out and undertake transmission investment that has either market or reliability benefits. The MCE has now also recently endorsed the establishment of a NTP, to commence operations in mid 2009, whose principal task will be to develop a long term strategic national transmission network development plan (NTNDP). The purpose of which is to provide a greater perspective on transmission investment needs over the long term including ultimately the impact of the CPRS and RET. As part of its information provision role it will also seek to provide early indication of where congestion might arise.

The CPRS and RET are expected to encourage the connection of more renewables, including intermittent generation to the network. These generators are likely to be located in more remote areas from the existing network and will represent a significant departure from where generation has located traditionally (near coal resources). This will change the configuration of the network, and in turn existing patterns of congestion, the materiality of which will be difficult to predict in advance, even by a well resourced NTP.

Moreover, an increasing quantity of intermittent generation will also require additional peaking generation capacity to ensure reliability is maintained. Given the low capacity factor of wind generation, it is unlikely that it will be economic for transmission investment to accommodate fully the capacity of both forms of generation, which means that there may be increasing situation where excess generating capacity will be competing for scarce transmission capacity.

The transmission investment arrangements tend to be triggered only if new investment is likely to generate net benefits to the market or is required in order for reliability standards to be met. Congestion which might be significant to individual generators may not be cost efficient to remove from a whole of market perspective (providing demand can be met from generators that are not constrained). Whilst participants who are exposed to this congestion could fund augmentations to remove it, the lack of firm access over the new capacity created removes the incentives for doing so, since this will only encourage competitors to co-locate to take advantage of this new capacity. While any new entrant would need to contribute to the original cost of the augmentation, they are not required to compensate existing participants if their dispatch adds to congestion. In other words, paying for transmission investment to remove congestion does not in fact reduce the congestion risk for that participant over time (if it encourages new entry).

Origin's key concern is whether transmission investment progressed through regulated means can keep pace with new and shifting patterns of congestion that may emerge (or whether indeed it is cost effective to do so). To the extent transmission investment falls behind, existing generators may inadvertently find themselves in positions of market power (being able to bid strategically on the importing side of constraints) or in a position of having their access to market reduced (if on the exporting side of the constraint). This could lead to ‘disorderly bidding’ which may increase wholesale price volatility and undermine efficient price outcomes.

The increasing emergence of new areas of congestion over time may increase the level of participant uncertainty around market access, for new investors as well as existing generation participants. This could have flow on implications for financing and investment decisions.

Firmer access

If transmission investment does not keep pace with increasing levels of congestion on the network the ‘open access’ nature of the transmission regime may substantially increase risks for participants, because their level of access to market will become difficult to predict and manage. As noted, there will also be minimal incentives for private parties themselves to fund transmission investment to remove congestion, because they cannot fully capture the benefits of doing so.

The implication of this going forward is that it may discourage investment in new generation, and reduce the capability of generation projects to underpin their investment with the appropriate level of finance. Debt and equity markets require comfort that investment won't be exposed to unnecessary cash flow risk. Increasing levels of congestion increases cash flow risk as it affects the level of access to market. This in turn will limit the amount of debt projects are able to raise, and increase required hurdle rates.

It is likely that the ability to achieve firmer access to transmission, and therefore the regional reference prices at major contract trading hubs, would support investment and reliability in the NEM, as the cash flow risks would be reduced for investors in generation capacity.

Origin therefore considers it may be worthwhile for this Review to consider alternative mechanisms, other than transmission investment, for addressing the level of congestion risk in the NEM. Much work has already been done on such mechanisms, and we consider that this work may need further attention. Origin has previously indicated its support for selectively applied contract support and pricing arrangements and intends to consider the potential for this and other approaches in more detail for further input into this Review.

6.3 How material are the risks of "contractual congestion" in gas networks and how might they be managed?

It is important to note that different markets for gas operate in SA, QLD, and NSW relative to VIC. In these states, investment in new capacity is primarily market driven. Pipeline owners assess the demand for pipeline services and are happy to expand capacity providing shippers underwrite such capacity. Shippers are happy to do this as they will have firm rights over capacity (shippers will be able to supply a known quantity of gas from an injection point to an off-take point using that capacity). Therefore it is not likely that contractual congestion will occur in these markets.

This differs to Victoria which operates as an "open access" regime. Like the NEM transmission capacity is allocated on the basis of bids regardless of who has underwritten that capacity. While existing AMDQ rights do provide some measure of protection against congestion, non AMDQ holders can use capacity paid for by others without contributing to the costs of such capacity. Thus private incentives for investing in gas transmission in Victoria are much weaker than in other states. A regulatory test needs to be relied upon to ensure sufficient investment occurs in the network. However there is significant concern among participants that this process is too slow and ineffectual and will not deliver the capacity needed in a timely fashion to support a substantial increase in the demand for gas in the context of a CPRS.

6.4 How material is the risk of inefficient investment in the shared network, and why?

There is some risk of inefficient locational decisions within regions by generators because they do not bear the full cost of the congestion they cause. The cost and risks of congestion are shared by all participants behind a constraint thus muting incentives for any one participant to factor congestion costs into its location decision. The potential for inadequate locational incentives to add to congestion over time could be addressed through the availability of firmer access to transmission, which would allow compensation for rights holders where new generation locates in already congested areas.

A further potential area of reform is the cost allocation arrangements for significant transmission investments which pass the regulatory test, where the benefits are spread across different regions, but the actual transmission costs fall within one (or fewer) regions.

This is likely to become an issue of increasing importance, as the CPRS and RET will over time require access to more remote renewable resources which may be located within particular states, however the benefits of unlocking these resources for meeting climate change policies will be national. To have one state's consumers bear the substantial shared network reinforcement costs needed to support large and expensive network extensions which benefit the whole market is unlikely to be politically unacceptable.

This issue was identified in the AEMC review of national planning arrangements, but needs to be progressed and resolved under this current review if climate change targets are able to be met in a timely and least cost fashion.

6.5 How material is the risk of changing loss factors year-on-year?

Many renewable investments are underwritten by contracts with retailers. One key risk that has emerged under the current regime is the year to year variability in Marginal Loss Factors, which is generally passed on to retailers.

Experience has shown that the MLF can change significantly from year to year, and further changes are likely given the sustained investment required to meet the expanded CPRS and RET.

7 Retailing

Summary of key points

- The fundamental concern for retailers under the CPRS is the ability to pass through carbon costs.
- Deregulation of prices is unquestionably the most efficient and simplest solution for managing carbon pass-through risk
- In the absence of deregulation the AEMC should develop a common methodology that can be applied consistently across jurisdictions.
- This process should commence immediately so that any methodology can be considered in next jurisdictional tariff reviews.
- Early auctioning of permits in 2009 is important for creation of an early price signal for carbon, which in turn can be incorporated in carbon methodology.

7.1 How material is the risk of an efficient retailer not being able to recover its costs, and why?

7.2 What factors will influence the availability and pricing of contracts in the short and medium term?

The CPRS will require emissions intensive generators to purchase permits in order for them to generate. The value of the permits they buy will effectively form an addition to the variable costs of each MW of energy produced, which will be reflected in generator bid prices in the wholesale market. Due to the variations in emissions intensity of different generators, the extent to which permit prices are reflected in the clearing price will depend on the emissions intensity of the marginal generator and the extent of competition between generators relative to the level of demand (which in turn determines who the marginal generator will be).

Over time, wholesale pool price forecasts will incorporate forecasts of CPRS costs and would therefore form, as now, the appropriate reference point for negotiating commercial contracts as well as establishing the forward looking wholesale component of regulated retail tariffs for small customers.

In the shorter-term, however, over the transitionary phase of the CPRS, it will be very difficult to predict how future wholesale prices will be impacted by the CPRS as there will be no history of prices on which to base such an assessment. Establishing the appropriate cost of carbon in contracts, and retail tariffs, will be a difficult exercise in this uncertain environment. This uncertainty is reflected in the current lack of liquidity in wholesale supply contracts beyond 2010.

The complexity of estimating carbon costs for inclusion in retail tariffs lends strong weight to arguments for fully deregulating retail tariffs post 2010, as getting it wrong could expose retailers across the board to significant margin squeeze and loss of profits. This will reduce competition and new entry with flow on implications for contract market liquidity and generation supply.

Consequently, if full price deregulation is not progressed in the early phase of the CPRS, it will be critically important that a consistent methodology for carbon cost pass-through is developed. This would ensure that the competitive landscape facing retailers remains neutral across jurisdictions and that the regulatory risks do not vary by state. The prospect of different jurisdictions adopting different approaches to the pass through of CPRS costs is of key concern for Origin.

The Ministerial Council on Energy (MCE) should commit to establishing a single national framework for assessing the relevant costs of the CPRS (under the auspices of the Australian Energy Regulator) and direct the AEMC to develop a common methodology for determining the cost of carbon in retail tariffs. This process should commence immediately, as it is essential that the elements of the framework are in place and agreed by jurisdictional Ministers prior to the end of the current retail price determination periods, most of which are up for review prior to or in 2010.

As a starting point, Origin suggests that a national approach could be based around estimates of permit price outcomes from early auctions multiplied by some agreed level of emissions intensity (based on some estimate of the level of carbon cost pass-through). In this regard, however, it is important that the first auctions are brought forward from late 2010 to mid to late 2009 to fit into the retail tariff reset schedules that are being imposed by the jurisdictions.

7.3 How material are the risks of unnecessarily disruptive market exit, and why?

Due to volatility or high prudential requirements, retailers may exit the market. In particular, the early years of the CPRS will create additional difficulties for retailers due to uncertainties and inexperience with the Scheme parameters for both generators and retailers. The need to acquire increasing proportions of renewable generation in the retailer's portfolio and expanded obligations to support various efficiency and renewable energy schemes adds to costs and uncertainty.

Given this, it is possible that a number of existing retailers (particularly those operating without a generation portfolio) will choose to exit the market. Some will do so in an orderly fashion by consolidation or sale, some will do so under financial stress.

Currently, each state has adopted a different approach, and different timetable, to the development of a Retailer of Last Resort (ROLR) Scheme. Origin notes that a number of these jurisdictional ROLR schemes have failed to recognise the current operational and financial risks to the ROLR retailer following a default. These risks are likely to increase under a CPRS scheme given the greater complexity for the ROLR of acquiring a suitable mix of hedging contracts and renewable energy certificates in a ROLR event scenario.
Origin has strongly supported the MCE/COAG commitment to developing a national ROLR scheme to replace these various jurisdictional schemes.

The approach set out in the Draft National ROLR Review addresses many of Origin's concerns with some of the jurisdictional schemes and is generally supported by Origin (see our submission to this Review). Critically, the proposed national scheme goes some way to recognising the risks and costs to the ROLR entity associated with its responsibility to supply the defaulting retailers' customers, and provides an approach that will enable the ROLR to recover the reasonable costs of providing the ROLR service.

The proposed national scheme therefore will provide greater confidence in the retail market. Additionally, by facilitating the development of a competitive market in the provision of ROLR services, the proposed national ROLR scheme will ensure, longer term, the delivery of a least-cost solution for customers.

In summary, the introduction of the CPRS, expanded RET and increased demands on retailers for efficiency programmes all increase the risk of a ROLR event (particularly in the adjustment period) and, simultaneously, increase the requirement for an effective and fair national ROLR arrangement. Origin supports the current proposal for a national ROLR scheme. Origin therefore urges COAG to commit to implementing the national ROLR scheme by the time the CPRS commences.

8 Financing new energy investment

Summary of key points

- The CPRS and RET trajectories will have implications for the need and timing of network infrastructure.
- New approaches to funding transmission infrastructure need to be explored.

8.1 What factors will affect the level of private investment required in response to climate change policies?

8.2 What adjustments to market frameworks, if any, would be desirable to ensure this investment is forthcoming at least cost?

The CPRS and RET will require a large investment in low emissions technologies (renewable and gas) as well as in energy networks. This will lead to major new requirements for financing energy infrastructure and generation over a short period.

The volume of intermittent generation entering the market and the areas where these generators choose to locate will have implications for congestion and systems security, and ultimately on what augmentations are needed to the transmission networks. For e.g. as the volume of wind generation grows in SA the interconnector may need to be upgraded.

In the case of the CPRS the carbon price and emissions trajectory will have a direct bearing on the economics of all types of generation and indicate how much investment in lower emissions technologies is needed to transition to a carbon constrained future.

The RET trajectory will have implications for how quickly renewable generators get built. The speed at which renewables (particularly wind) enter the market is important as this will have implications for the need and timing of investment in network infrastructure required to accommodate the increased volume of wind in the market.

The development of new sources of renewable generation such as geothermal will impact on the need for new transmission infrastructure, particularly if the technology is proven in time to take advantage of the RET.

Given some of the market failures associated with building transmission infrastructure (e.g. first mover problem) it might be necessary to have some public funding of network as outlined in Section 5.

The development of an appropriate IRTCM is needed to ensure the funding of transmission infrastructure that will result in inter-regional benefits e.g. interconnector upgrade.

Upgrade to the interconnector, could mean that more wind generators can be accommodated in regions such as SA, without compromising systems operations. This means that wind farms would be less likely to be 'constrained off' or incur added FCAS costs, which should ultimately lower investment costs.

The role of the NTP will be important since it will take a holistic view of the transmission network and will be best placed to identify when/where network augmentations are needed.

The NTP might be called upon to advise the AEMC to exercise its Last Resort Planning Power to direct TNSPs to undertake the Regulatory Test if a planning failure is identified. This could ultimately lead to a TNSP building a particular transmission element and it being rolled into the Regulatory Asset Base, provided it passes the Regulatory Test and is approved by the Australian Energy Regulator under its Revenue Reset process.