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Dr John Tamblyn
Chairman
Australian Energy Market Commission
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Dear John

VENCORP'S RESPONSE TO THE AEMC SCOPING PAPER FOR THE REVIEW OF ENERGY MARKET FRAMEWORKS IN LIGHT OF CLIMATE CHANGE POLICIES

VENCorp welcomes the opportunity to make a submission on the Australian Energy Market Commission's (AEMC) Scoping Paper for the *Review of Energy Market Frameworks in Light of Climate Change Policies*.

In this submission, VENCorp has identified the following priority issues:

- **Electricity market design** – The energy-only market should continue to operate with improvements to the market price setting and markets for ancillary services. In addition, there is a need for further promotion of the role of demand-side response and the electricity futures market, which complements the physical market.
- **Gas network planning** – While the introduction of the Bulletin Board and development of the Short-Term Trading Market and Gas Statement of Opportunities represent important progress in the development of the gas market, there may be a need for a strategic, national approach to gas network planning in the long term.
- **Electricity transmission network** – The economic framework for the development of the electricity transmission network needs to progress alongside physical changes to the network in the areas of network planning, network connection and network capability.

VENCorp is of the view that the implementation of climate change policy is the most significant challenge to the energy market in recent times, and looks forward to engaging further with the AEMC during the course of this important Review.

Should you wish to discuss the contents of this submission, please do not hesitate to contact John Howarth on (03) 8664 6565 or Louis Tirpcou on (03) 8664 6615.

Yours sincerely

G J Cook

Graeme Cook
Interim Chief Executive Officer

VENCORP SUBMISSION ON THE SCOPING PAPER OF THE AEMC REVIEW OF ENERGY MARKET FRAMEWORKS IN LIGHT OF CLIMATE CHANGE POLICIES

1. EXECUTIVE SUMMARY

On 10 October 2008, the Australian Energy Market Commission (AEMC) published a Scoping Paper as the first stage in its *Review of Energy Market Frameworks in Light of Climate Change Policy* (the Review). The Review has been directed by the Ministerial Council on Energy (MCE) to review the current energy market framework, to determine whether aspects of the framework will need adjustment with the introduction of the Renewable Energy Target (RET) and Carbon Pollution Reduction Scheme (CPRS).

VENCorp plays a unique role in the Australian energy market and its functions will soon be a cornerstone of the Australian Energy Market Operator (AEMO), which will commence operation from 1 July 2009. Currently, VENCorp has a number of key wholesale gas and electricity market responsibilities including the following:

- Market and system operation of the Victorian gas market;
- Planning and procurement of the Victorian shared electricity transmission network;
- Planning of the Victorian gas Principal Transmission System (PTS);
- Operating and administering the retail gas markets in Victoria and Queensland;
- Supporting the wholesale and retail gas markets in South Australia and Western Australia;
- Developing a Short-Term Trading Market for New South Wales and South Australia;
- Developing of a Gas Statement of Opportunities; and,
- Operating the Gas Bulletin Board for the eastern Australian gas markets.

In this submission, VENCorp has adopted a forward-looking approach to the possible effect of climate change policy on the energy market. It has highlighted what it considers to be key areas for further investigation as part of this Review (primary drivers) and those matters that, while likely to improve the efficiency of the energy market, can be addressed through the normal Rule-change process (secondary drivers)

There will continue to be conjecture about the possible effects on the energy market until further detail is released by the Commonwealth Government in its White Paper in December 2008. The implications of the national RET for renewable generation is uncertain, in part due to uncertainty about how the scheme will operate, and also because of considerable uncertainty about the technical feasibility of some renewable generation. Anecdotally, the information available suggests that significant changes in electricity market dispatch will only occur with a carbon price of $\$40/tCO_2$ or more.

For this submission, VENCorp has used a simple marginal cost supply curve approach to consider the potential impact of the RET and CPRS on the energy market, by looking at possible scenarios on carbon policy that are consistent with VENCorp's approach to *Vision 2030*. VENCorp is currently updating *Vision 2030*, which was initially published in 2005. *Vision 2030* uses scenario planning to develop a 25-year road map of the Victorian energy sector. VENCorp will release the updated version of *Vision 2030* in early 2009 and will inform the AEMC of any developments arising from the *Vision 2030* review.

With VENCorp's experience in gas market operation and electricity transmission network planning, this submission will focus on the following issues:

Electricity Market Design
VENCorp believes that the current energy-only market design has provided efficient investment outcomes to date, and that deviation from this model would be counter-productive. Within this energy-only framework and taking into account the impact of the RET and CPRS on the energy market, VENCorp supports further consideration of the appropriateness of electricity spot market price settings and markets for ancillary services. VENCorp also believes that further promotion of demand-side response and the role of the electricity futures market in providing an effective future price signal would lead to more efficient energy market outcomes.

Further development of gas network planning frameworks
VENCorp expects that current gas reserves in Australia will be sufficient to provide fuel for new gas-fired generation that may enter the market as a result of the CPRS in the short term. While current gas planning frameworks are developing gradually, there may be a need for a more strategic, long-term approach to planning following the introduction of the CPRS.

Utilising the electricity transmission network effectively
The electricity transmission network must be utilised effectively to accommodate large amounts of new gas-fired generation and wind energy that are expected to enter the energy market following the introduction of the RET and CPRS. This involves further development of the following aspects of the electricity transmission framework:

- Transmission planning frameworks;
- Connection arrangements, especially where generation is remote; and,
- Improving information about transmission network capability.

Attachment 1 to the submission provides VENCorp's response to the individual questions raised by the AEMC.

2. INTRODUCTION - AN ENERGY MARKET OUTLOOK

The Australian Government's introduction of a national Renewable Energy Target and Carbon Pollution Reduction Scheme will change the generation mix. However, there is uncertainty about the nature and degree of change.

Anecdotally, the information available suggests that significant changes in electricity market dispatch will only occur with a carbon price of $\$40/tCO_2$ or more.

The likely effect of the national Renewable Energy Target (RET) and Carbon Pollution Reduction Scheme (CPRS) will be the lowering of the level of greenhouse gas emissions from Australia's electricity generation industry by influencing generation investment and operational decisions. These schemes, which will be introduced in mid-2009 and during 2010 respectively, will present the greatest challenge to the operation of the National Electricity Market (NEM) since its inception in December 1998.

In the long term, the introduction of these schemes may prompt the replacement of higher-emitting brown and black coal generators with lower emissions-intensive generators. This is partly contingent on the viability of Carbon Capture and Storage (CCS).[1]

In the short term, these carbon-reduction policies are likely to have a significant impact on the gas market, with gas-fired generation expected to constitute a large proportion of the new generation mix. As such, these policies will have considerable implications for both electricity and gas network investment.

The energy market framework, in its current form, was designed to accommodate gradual evolution rather than sudden changes like the challenge of climate change. Whether the market will deliver timely investment in both generation and network infrastructure to achieve these carbon-reduction goals is currently unknown.

Given this significant challenge to the energy market, the MCE has directed the AEMC to carry out a *Review of Energy Market Frameworks in light of Climate Change Policies*. As the first stage in this Review, the AEMC published a Scoping Paper on 10 October 2008.

In this Scoping Paper, the AEMC identifies a number of issues that are likely to be relevant to the Review, and has called for submissions to address these issues. These issues are:

- Convergence of gas and electricity markets;
- Generation capacity in the short term;
- Investing to meet reliability standards and increase use of renewables;

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[1] The Australian and Victorian Governments both support CCS as a means of capturing emissions from coal plant. The Victorian Government introduced legislation into the Victorian Parliament in September 2008 to enable the onshore injection and permanent storage of carbon dioxide and other greenhouse gases. On 11 November 2008, the Australian Government introduced legislation that establishes access and property rights in Australia's offshore waters for geological storage of CO2 (*The Offshore Petroleum Amendment Bill*).

- Operating the system with increased intermittent generation;
- Connecting new generators to energy networks;
- Augmenting networks and managing congestion;
- Retailing; and,
- Financing new energy investment.

The Energy Market Outlook: Implications For Electricity Markets

This section sets out some scenarios about the possible change in electricity generation resulting from the introduction of a national RET and CPRS, which may change the generation mix significantly. Both schemes will be aimed at encouraging the introduction of more low-emissions technology into the market, with expected new renewable investment from the RET and new gas-fired generation from the CPRS.

While the exact impact on the market is currently unknown, the introduction of a carbon price is likely to make coal-fired generation less attractive commercially, and, depending on the degree of transitional assistance from the Australian Government and the viability of carbon capture and storage (CCS), may lead to the retirement of some brown coal-fired plant. The increased cost of base-load, coal-fired generation, and shift to higher-cost generation in general, may result in price increases for some market participants and end-users.

An increased reliance on gas-fired generation will also change the economics of the Australian gas market as domestic demand grows. This is likely to create demand for new gas transmission pipeline investments to supply gas to these generators.

A CPRS will price greenhouse gas emissions, to increase the cost of higher-emitting generation as compared with lower-emitting generation. This is expected to make lower-emitting generation relatively more cost-competitive than higher-emitting generation. This competitiveness will increase as prices for emissions increase.

The expanded national RET is being designed to provide a positive incentive for renewable generation by requiring retailers to source a proportion of their load from renewable sources. This is expected to create a market for renewable energy, leading to increased investment in this generation.

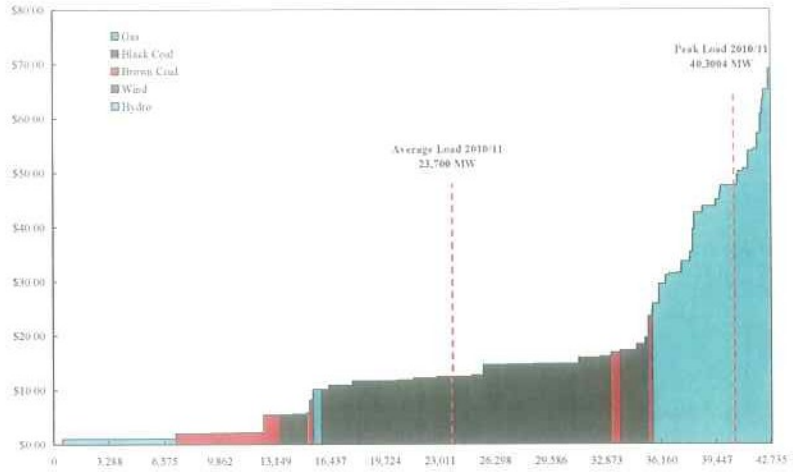
Uncertainty surrounds the type and location of new renewable generation that will result from the introduction of a national RET. A number of options are possible, including:

- Increasing wind generation, particularly in South Australia and parts of Victoria where wind generation is most suitable;
- Ongoing development of solar and geo-thermal generation, which if feasible, would be located in remote parts of Australia with geo-thermal largely in remote South Australia; and
- Increasing renewable distributed generation, such as domestic solar energy.

There is some uncertainty about the penalty amounts that will apply to the CPRS and the national RET. A simple, but insightful, marginal cost supply curve approach to analysing these changes is given below, at Figures 1, 2 and 3. These Figures indicate the change in the

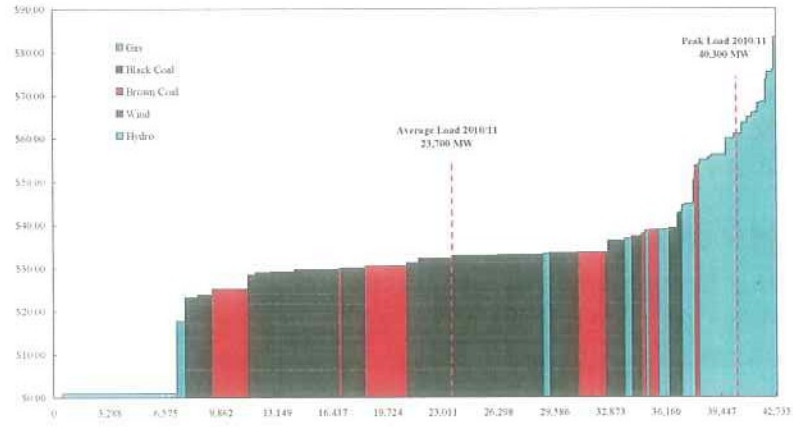
electricity generation merit order following the introduction of the CPRS, in circumstances where carbon prices increase to $20/tCO2 (Figure 2) and $40/tCO2 (Figure 3).

Figure 1: Electricity generation merit order – pre-CPRS



Source: NERA Economic Consulting

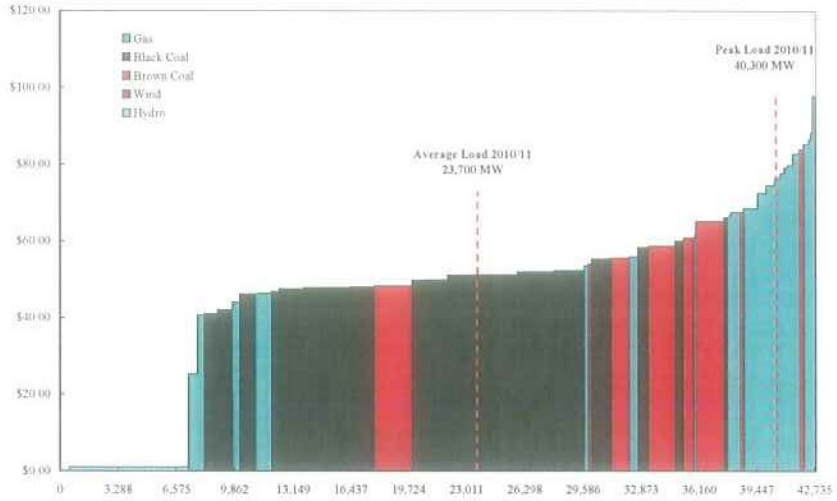
Figure 2: Electricity generation merit order – CPRS with $20/tCO2



Source: NERA Economic Consulting

Figure 2 shows that a $20/tCO2 price would result in limited changes to the merit order of generation.

Figure 3: Electricity generation merit order – CPRS with $40/tCO$_2$



Source: NERA Economic Consulting

These figures indicate that brown coal generation is expected to shift upwards in the merit order following the introduction of a CPRS. The brown coal generation would be replaced by gas-fired generation supplying base-load electricity. However, carbon capture and storage would have the effect of shifting coal generation downward in merit order.

The implications of the national RET for renewable generation is uncertain, in part due to uncertainty about how the scheme will operate, and also because of considerable uncertainty about the technical feasibility of some renewable generation. This suggests that, at least in the short term, most new renewable generation will be wind generation.

The Energy Market Outlook: Implications For Gas Markets

The introduction of the national CPRS in the short term is expected to lead to an increase in gas-fired generation in the NEM. Over time, gas-fired generation may become a significant part of Australia's electricity generation capacity. This will depend on the design of the CPRS and the effectiveness of CCS technologies. In the short term, the introduction of the CPRS is expected to lead to increased investment in gas-fired generation, most likely located in Queensland and New South Wales.

The implications of this growth in gas-fired generation for the gas market are:

- increased demand for gas to fuel new generation investments; and,
- potential need for new pipeline investments to provide sufficient capacity in locations where gas-fired electricity generators are likely to locate; and,
- gas usage will become increasingly erratic, as it responds to the dynamics of intermittent generation. This will have implications for gas storage.

Already there has been significant private investment in gas-fired generation in the NEM. In recent years, there has been a trend towards gas-fired generation as a generation technology. The 2008 Statement of Opportunities has noted 5359 MW of proposed gas-fired generation between 2008/9 and 2012/13.

VENCorp's *Vision 2030*

As the Victorian Gas Market Operator and the independent planner of the Victorian shared electricity network, VENCorp has carried out forward-looking analysis on the ability of the Victorian energy sector to deal with climate change in the following documents:

- In 2005, VENCorp released Vision 2030. In Vision 2030 VENCorp uses scenario planning, with scenarios developed through extensive industry consultation, to outline a 25-year energy sector road map. The scenarios were modelled to determine transmission capacity requirements, with 'carbon response' being one of the scenarios. Vision 2030 has indicated that the total requirements for potential investment are in the $1 to $2 billion range. Vision 2030 assumed that a large amount of wind power will be necessary in meet Victoria's future load.

  VENCorp is currently updating Vision 2030, with a planned release of March 2009. In this update, VENCorp will principally review four long-term scenarios facing Victoria's energy networks, with a particular focus on the regulatory changes in response to climate change. It will consider any necessary changes to network development plans set out in the current Vision 2030 document.

- To complement *Vision 2030*, VENCorp conducted a study on the "Capacity of the Victorian Electricity Network to Integrate Wind Power" (December 2007). This report found that with the appropriate technical solutions, the Victorian transmission network can accommodate wind generation of around 3,000 MW installed capacity, and possibly up to 4,000 MW, depending on the location of generation.

The remainder of this submission focuses on the key issues for the energy market that will result from these changes to the energy market. The first of these issues is the ability of the current electricity market design to attract sufficient new investment in generation to meet carbon-reduction targets.

3. ELECTRICITY MARKET DESIGN

The current energy-only market design has provided efficient investment outcomes to date, and that deviation from this model would be counter-productive. Improvements to the current investment framework could include the following:

Primary drivers

- Further consideration of the appropriateness of electricity spot market price settings with possible alignment with the true value that consumers place on energy;
- Consideration of markets for ancillary services;
- Increased promotion of demand-side response; and,
- Promotion of the electricity futures market in providing an effective future price signal.

Secondary drivers

- Sharper investment signals though 5-minute dispatch and 5-minute settlement model.

As the energy market deals with the introduction of new carbon-reduction policies, one of the key issues will be the ability of the market to attract timely and efficient generation investment to ensure reliability of supply. As the scenarios suggest, the need for generation and the mix of this generation will vary according to the choice of carbon price. It will also depend on whether brown coal generators continue to operate, which in turn may depend on the degree of transitional assistance provided by the Federal Government and long-term success of CCS technology.

The potentially sudden introduction of large amounts of wind generation will also require new back-up generation, most likely in the form of open-cycle gas turbines. This section looks at the following as issues for new generation:

- The NEM's energy-only market design;
- The effectiveness of market price settings in the NEM;
- Promoting demand-side response in the market; and,
- The role of a deep and liquid futures market in providing future price signals for potential investors.

The NEM's Energy-Only Market

VENCorp firmly supports the energy-only market design in the NEM, and believes that it has provided efficient investment outcomes in the NEM to date. VENCorp is not in favour of the AEMC considering capacity mechanisms to attract new investment in the course of this Review. Capacity payments or a capacity market would represent a significant departure from the current framework, and consideration of a capacity model alone would be disruptive and would create further uncertainty in the market.

Further, overseas experience indicates that capacity markets can lead to negative market-related outcomes. The American Pennsylvania-New Jersey-Maryland (PJM) carried out a comprehensive re-design of its capacity market, and introduced a new capacity market in 2007, because the previous model was encouraging high concentrations of market power.[2]

Despite employing nodal pricing, both the previous PJM and the New England capacity markets were not designed to attract new generation investment at the most optimal locations. In fact, due to only 11 MW of new capacity entering the New England market in 2005 and 2006, the Federal Energy Regulatory Commission ordered New England to re-design its model to improve its locational signals. The PJM introduced a new capacity market (the 'Reliability Pricing Model') in 2007, and New England introduced its new capacity market in 2008 ('Forward Capacity Market').

With these well-established American markets still refining their capacity market models to improve locational signals for investors and prevent against the abuse of market power, Australia should not consider changing its model unless there are significant proven economic benefits of doing so.

Adjusting Market Price Settings

The spot price cap is an important signal for attracting new generation. In an energy-only market, prices for electricity in the spot market directly influence investment decisions. Spot market prices should attract the right amount of investment balanced by the right amount of activity in the demand-side of the market. Under competitive conditions, spot prices should reflect supply-demand dynamics, indicating the level of new capacity required.
In energy-only markets, spot markets drive these price signals. If the market is competitive, high spot prices should only materialise during a small number of hours each year when demand is high and supply is scarce. These high prices each year provide profits for peak-load and intermediate generators, which supply energy during these few hours of peak demand. This wholesale market price volatility is important for attracting investment.

Market price settings, especially the price cap, must be set high enough to provide these peak generators with a profit over and above their capital investment and operating costs during peak periods, to attract their investment in the market. Although the price cap or 'value of lost load' (VoLL) in the NEM is being raised to $12,500, the AEMC should consider whether this new cap is sufficiently high to attract timely investment in the new carbon-constrained environment.

In Victoria, VENCorp applies the Value of Customer Reliability (VCR), which is a measure of the cost of unserved energy that VENCorp applies to Regulatory Test assessments for planned augmentations to the Victorian electricity transmission system. The VCR is determined through a customer survey approach that estimates direct end-user customer costs incurred from power interruptions at the sector and state levels. Unlike the NEM price cap, the VCR is measured through customer surveys and reflects the demand-side's willingness to reduce usage.

[2] *PJM State of the Market Report* (2006).

The Rules stipulate that the Reliability Panel, in reviewing the level of VoLL, must have regard to investment in the electricity market and reliability of the power system. VENCorp believes that the Reliability Panel, in its next Review of the price cap, take into account the likely changes to the incentive structure for investment in new generation post-CPRS to ensure that the price cap supports reliability in new investment conditions. It should also consider incorporating the value of demand by determining customer preferences.

Encouraging More Demand-Side Response In The Market

The spot market price cap must also be high enough to encourage further use of demand-side response (DSR). DSR is one of the benefits of more dynamic price-signalling that has resulted from liberalisation. DSR can reduce the pressure on the system during peak periods. Regular use of DSR, along with direct load control and household interval meters, would reduce the need for investment in peak-load generating capacity. Greater elasticity of demand, through DSR, also improves competitive market conditions.

DSR has been a gradual and slow addition to the NEM. In 2007, the Energy Reform Implementation Group estimated around 700 megawatts of potential DSR in the NEM. NEMMCO also procures DSR through Reserve Trader. It is likely that some DSR is unreported.

VENCorp would support active promotion of and education among industrial users about the role that DSR can play in reducing usage during peak periods. The Commission should consider this during the course of the Demand-Side Participation Review.

5/30 Dispatch Intervals In The NEM

The NEM spot market currently uses a 5-minute dispatch interval, but settlement takes place by averaging six 5-minute intervals over a 30-minute period. A 5-minute settlement model would result in greater cost-reflectivity, and would allow NEM participants that can start up quickly to respond effectively to 5-minute price signals. VENCorp would support re-opening this issue, which NEMMCO investigated in 2001/02.

Providing Appropriate Incentives For Investment In Back-Up Generation

The introduction of more wind energy in the NEM, as a result of the Renewable Energy Target (RET), will require increases in back-up generation to manage the increased intermittency of supply. This back-up generation will need to be sourced from existing generation, or new generation that enters the energy market. The incentives available from the markets for ancillary services are on their own not enough to justify building new power plant. These incentives should come from energy market signals and carbon price signals. Capacity markets or payments would be a further distortion to these two incentive drivers.

As wind energy can ramp up suddenly and uncontrollably, generation must be available to lower it through the 'raise' and 'lower' regulation Frequency Control Ancillary Services (FCAS). This back-up generation must already be spinning, or have the ability to ramp up quickly. Hydro electricity can match the ramp rate of wind but most states, including South Australia and Victoria where most new wind is likely to be located, have limited hydro-electric generation. With a $20 carbon price, thermal brown coal generation may continue to provide back-up support for wind generation, depending on its location. In VENCorp's view, the FCAS market design will need to be reviewed if a change in the merit order dispatch of generation occurs. This would be in the interests of ensuring continued secure and reliable supply.

Promoting A Deep And Liquid Futures Market

The market for tradeable electricity futures on the Sydney Futures Exchange can be seen as the energy-only market's 'capacity' mechanism. This is because a deep and liquid financial market provides potential investors with a strong signal of future energy prices.

Where contracts are listed on the futures market, they are transparent and provide a price signal to potential investors. The longer the duration of financially-traded products, the greater the future price certainty is for potential or new investors. In Australia, electricity futures products are currently going out up to four years. These prices are determined by market participants based on market conditions, taking into account a number of factors. One of the factors currently being considered by traders is the future carbon price.

The strength of the signal depends on the volume and liquidity of the market. Over-the-counter (OTC) contracts that were more commonly used before the futures market developed, on the other hand, are traded bilaterally and are not transparent. For this reason, the market would benefit from a continued shift towards transparent futures trading, and greater awareness about the role of financial markets.

4. IMPLICATIONS FOR THE GAS MARKET AND GAS NETWORK PLANNING

The CPRS will drive further convergence between the gas and electricity markets. There has been important recent progress in the development of transparent gas markets in Australia. Improvements to the current framework could include the following:

Primary drivers
There may be a need for a more strategic, long-term approach to gas network planning following the introduction of the CPRS.

Gas Market Design

As the AEMC has noted in its Scoping Paper, the Government's policies to address climate change are likely to increase the use of gas as a source for electricity generation. As discussed in Section 2, there are already significant amounts of proposed gas-fired generation earmarked to enter the NEM.

Distinct from climate change policies and related implications for the electricity market, the gas market has been undergoing a rapid transformation as technology has improved for the extraction of coal-seam methane, resulting in significant increases in gas availability on the Eastern seaboard.

This has led to planned investments in LNG production facilities, fed by gas from coal seam methane, in Queensland. These investments may have implications for domestic gas prices, which have been historically lower than world gas prices.

However, as coal-seam methane gas production is increased in advance of the commissioning of the LNG plants, there is expected to be surplus gas available for the domestic market. This surplus gas should particularly benefit existing gas-fired generation. As such, investors in new gas generators will still need to negotiate longer-term gas supply contracts to support generation investment.

In its Scoping Paper, the AEMC has raised gas market design as an issue, particularly price-responsiveness in the gas market. The gas market has developed more slowly than the electricity market at a national level. However, the Bulletin Board and soon-to-be-established Short-Term Trading Market, both short-term instruments, have been initiated to improve transparency and price-responsiveness in the gas market.

The STTM will be a day-ahead wholesale gas market where suppliers and sellers can trade gas at a hub. This day-ahead market establishes a daily hub price for gas and settles gas consumed at the hub. The Victorian gas market will continue to operate as it currently does. The STTM will initially operate in the NSW and South Australia with Queensland and ACT likely to join at a later stage. A national operating gas market presents a potential area for improved transparency and investment signals.

The STTM and Bulletin Board will feed off the long-term Gas Statement of Opportunities. The Victorian gas market now has ex ante pricing and runs according to five daily intervals, representing an improvement in cost-reflectivity and responsiveness to market dynamics.

Gas Supply

There is likely to be gas available, at reasonable prices, to support the necessary expansion in gas-fired generation that will be required in the near-to-medium-term future. The core uncertainty in the medium term is likely to be where gas-fired generation will be located, and the availability of network capacity for transportation of this gas. The most likely candidates are Queensland and/or New South Wales. For NSW to be a feasible location, construction of gas pipelines are necessary to provide sufficient capacity to supply these new generators.

While there appears to be sufficient gas reserves for to fuel gas-fired generation in the near-to-medium-term future, there may be constraints on gas supplies in the longer term for the following reasons:

- While gas can be stored, gas storage, including linepack in Victoria, is limited. Further, under-ground storage facilities in Australia are few in number and those that exist are small and remote from load centres. Gas demand is likely to become 'peakier' as more gas-fired generation is needed to support wind generation, requiring adequate storage facilities.

- Australia currently has healthy gas reserves, but much of these reserves are located in Western Australia on the North West Shelf, far from load centres. VENCorp's 2008 Annual Planning Report estimates Victoria's total recoverable reserves at 9173.9 PJ. This equates to 5.9% of Australia's total recoverable reserves, which are estimated to be 154226.8 PJ. Victoria currently exports some of this gas, and future reserves will depend on export levels.

Gas Network Planning Arrangements

Existing arrangements within the gas market would be expected to adequately address these investment needs in the case of incremental changes to the gas industry. Historically, there have been examples of pipelines being financed and constructed by consortiums of electricity generator investors (for example, the SEA Gas pipeline was constructed as a joint venture by TruEnergy, Origin and International Power to fuel gas-fired generators in South Australia). However, the climate change response and the resulting need for gas network augmentation may be on a scale larger than anything previously experienced. With this in mind, there may be a need for a more strategic and economic long-term approach to gas network planning.

It is also expected that new wind generation in the NEM will require back-up generation that can start up swiftly. This back-up generation may be open-cycle gas generation, which will also require support from the gas transmission network.

Recent gas pipeline investments have been typically supported by contractual arrangements between parties, with a limited formal pipeline planning framework. The exception has been Victoria, where VENCorp prepares an Annual Gas Planning Report, which provides information on gas demand and supply, and transmission capacity within the Principal Transmission System. However, VENCorp only advises the market about the need for appropriate augmentations, and assists participants once they proceed. VENCorp does not direct these augmentations.

The Gas Market Leaders' Group is currently developing the framework for a Gas Statement of Opportunities (Gas SOO), which would be prepared by the AEMO, and provide information on gas demand and supply conditions for a period of up to 10 years. In addition, the GMLG has

proposed that the SOO will cover information on gas storage, transmission network capacity and interconnection constraints.[3]

The Gas SOO is not intended to form the basis of centralised pipeline investment decisions, but rather to assist commercial enterprises to identify opportunities that may arise.

The Gas SOO is expected to have similarities to the Annual Planning Report prepared by VENCorp, which provides forecasts of energy demand and supply and identifies future development requirements for both the electricity shared transmission network and the gas Principal Transmission System (PTS).

A more difficult problem for a gas-fired generator is accessing sufficient capacity in existing pipelines, in circumstances where the capacity is contracted but underutilised. Currently, there is no obligation on holders of contracted capacity or pipeline owners for spare capacity of an uncovered pipeline to provide access to a new connecting user.

This means that for the majority of Eastern Australian pipelines obtaining access requires direct negotiation with the pipeline owner or contractual capacity holder. In the event that the access-seeker fails to negotiate access on acceptable terms and conditions, the only remaining option would be to seek coverage for the pipeline, before engaging in an access dispute proceeding in accordance with the rules. This approach would take considerable effort on the part of the access-seeker, thereby creating a potentially significant impediment to access.

If a pipeline is covered, (for example, the PTS in Victoria), then it is possible to seek access to spare capacity, even when this capacity has already been contracted to a third party. It is arguable that the National Gas Rules allow for an access dispute determination to require access to contracted capacity, although only where the contractual rights are not reduced. This suggests that access to the available capacity might be limited to an interruptible form. For a gas-fired generator, firm access would be required.

VENCorp is not aware of any proposed gas-fired generators having difficulties accessing either gas supplies or pipeline capacity, which would warrant changing the current approach in gas. Current developments such as the AEMO having responsibility to prepare an annual Gas SOO, and the national gas market Bulletin Board, will likely result in significant market awareness of the commercial pipeline capacity and supply opportunities that will arise from an increase in demand for domestic gas.

However, there have been short-comings even in Victoria, where commercial positions do not always align with economic considerations. On one notable occasion this has required VENCorp to propose an augmentation to the PTS which would otherwise not be constructed because of potential free-riding issues, should it be built by a commercial player.

While the current arrangements seem adequate to deal with incremental changes to the market, sudden amounts of gas-fired generation entering the market in response to a CPRS may place added pressure on the network. The adequacy of network planning arrangements for the gas network required to accommodate this new gas-fired generation. For this reason, there may be a need for a more strategic, long-term approach to gas network planning following the introduction of the CPRS.

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[3] Page 11, Gas Market Leaders Group, (2008), *National Gas Market Development Plan – Scope of a National Gas Statement of Opportunities*, Industry Consultation Paper, August.

5. ELECTRICITY TRANSMISSION NETWORKS

The electricity transmission network must be utilised effectively to accommodate large amounts of new generation expected to enter the energy market following the introduction of the RET and CPRS. This involves further development of the following aspects of the electricity transmission framework:

- transmission planning frameworks;
- connection arrangements, especially where generation is remote; and,
- improving information about transmission network capability.

Primary Drivers

- National approach to inter-regional transmission pricing
- National approach to addressing firm access

Secondary Drivers

- Improvements in the distinction between prescribed and negotiated services

The RET and CPRS are likely to drive large amounts of electricity transmission investment to support expected changes in the geographic location of new generation investments, compared with existing generation. The location of both renewable generation and gas-fired generation will have implications for electricity transmission requirements. An effective economic framework for the operation of the transmission network is needed not only to accommodate new generation, but to provide important signals to investors about the optimal location of generation.

VENCorp is of the view that the economic framework must develop to match the physical changes to the network in the following areas:

- network investment, through planning arrangements;
- network connection; and,
- network capability.

Electricity Transmission Network Planning

A critical question for the Commission's review is whether current electricity and gas network planning and investment frameworks provide appropriate incentives for efficient network investment. Economic frameworks should signal the need for the right amount of investment, rather than under- or over-investment. Such a balance is difficult to strike.

The current electricity transmission network planning regime relies on a centralised planning framework, with specific transmission investments being undertaken when the benefits are found to exceed the costs, in accordance with the requirements of the Regulatory Test.

It is possible that the transmission network framework in the National Electricity Rules (NER) may not provide the incentives to drive timely and efficient network investments, to support renewable generation investments. This is because:

- the Rules governing major extensions to the network are not clear, such that inefficient duplication of a network extension asset might be promoted; and,
- the risks and costs involved with a major extension might be so large that they outweigh the potential benefits a renewable generator might receive from connecting to the network, in the absence of a consortium of generators being established.

In the climate change context, the Regulatory Test has been criticised as being unable to accommodate renewable generation through the market benefits limb. VENCorp is of the view that once a carbon price is set, investors will have the necessary information to compute the market benefits of augmenting the network under the Test.

This highlights that for electricity transmission networks, improving the arrangements for the planning of major extensions is an area for further investigation.

CONNECTION AND TRANSMISSION PRICING

Gas And Electricity Connection Regimes

There is potential for bias in generator locational decisions resulting from differences in the charging framework between the electricity transmission and gas network. For gas networks, the generator must fund any new pipelines necessary to produce its gas. However, in doing so, the generator generally obtains a contractual right to firm access for the expanded capacity. This is known as the 'contract carriage' approach.

For electricity transmission networks, augmentation is funded either through the Regulatory Test or it is paid for by the generator. However, unlike for gas networks, a generator who funds a shared network augmentation does not obtain any rights to the new transmission capacity. This difference in approach between electricity transmission and gas networks means that a new generator's locational decision could be skewed by the difference in the connection regime.

However, a decision about the location of a generator is based on a multitude of considerations, including: access to a fuel source on a firm basis; transmission losses to the regional load; and expectations about regional wholesale electricity prices. It is therefore unlikely that the theoretical bias would in practice affect a generator location decision.

Connecting Remote Generation

While the final design of the expanded RET is unknown, its introduction is likely to encourage large amounts of remotely-located renewable generation to enter the NEM, particularly wind generation. Under the current connection framework, a generator must pay for the full cost of connection (a shallow approach) and must pass the Regulatory Test to pass on its costs through the shared network. These requirements may act a barrier to the integration of this new remote electricity generation.

If designed effectively, connection charges can provide important long–run locational signals for generators. Currently the Rules for connection and access and the economic regulation of

networks are set out in Chapters 5 and 6A, respectively, of the National Electricity Rules (NER). Chapter 6A also provides Rules for transmission pricing.

The high cost for remote generation to connect to the network, via the shallow pricing approach, may act as an impediment to the integration of renewable energy to meet the Government's targets. This will depend on the location of the wind and its proximity to the network. It will also depend on the TNSP's ability to pass on any costs of augmentation through the shared network by passing the Regulatory Test.

The Regulatory Test has been criticised for not accommodating renewable generation through the market benefits limb. However, once a carbon price is set, VENCorp is of the view that it will have the necessary information to compute the market benefits of augmenting the network under the Test.

Improvements In The Distinction Between Prescribed And Negotiated Services

Another area where the NER lacks some clarity is in the area of shared transmission network augmentation classification. Where a generator requires the transmission network to be augmented to allow effective connection of the generation plant to the transmission network, the vagueness of the NER definition in many instances enable the augmentation work to be classified as either prescribed or negotiated.

The consequences are that if the augmentation is classified as a Prescribed Service, the cost of the augmentation is passed onto customers at large through TUOS charges. If classified as a Negotiated Service, the cost remains solely with the generator. The lack of clarity in the definitions of these services can differ from jurisdiction to jurisdiction, and circumstance to circumstance within the same jurisdiction. This uncertainty can lead to hesitation to invest since generators do not know with any certainty whether they carry the cost of network augmentation or not.

Coordinated network connections

The current NER do not encourage coordinated applications for connection to the network. As such, most applications for connection are negotiated bilaterally. This can be inefficient. Due to this gap in the Rules, VENCorp uses its Connection Guidelines to guide connections of multiple generators. Any Rules or guidelines about multiple connections must provide a guide for dividing these costs between connecting generators.

In considering any model to encourage coordinated connection, the AEMC must ensure that:

- it does not remove the incentive for new entrant generators to locate close to the network; and,
- it maintains the technology-neutral approach of the National Electricity Rules.

Inter-Regional Transmission Use Of System Charges (TUoS)

VENCorp strongly supports the introduction of a national framework for inter-regional TUoS, to ensure that costs associated with augmenting the shared network are allocated evenly between customers. This is particularly important as new generation that enters the market as a result of RET and CPRS is unlikely to be located proportionally across regions.

Improving Signals About Network Capability

The introduction of large amounts of new generation in the NEM could limit transmission network capability at specific points within regions and on transmission inter-connectors. This is likely to result in inefficient decision-making, while also reducing competition in the market. Locational signals within the connection framework will need to combine with further information about network capability for efficient utilisation of the transmission network to occur.

The AEMC has previously acknowledged, in its Final Review of Congestion Management, that the introduction of new generation driven by Government climate change policies may result in the emergence of material congestion. The Commission added that new Government policies introduced in response to climate change are likely to "stress test" the NEM's regulatory framework, including the Congestion Management Regime and that "even a proportionate response might involve significant reform to the regulatory Framework".[4]

In the new carbon-constrained environment, the current approach to pricing congestion in the NEM is inadequate for the following reasons. Intra-regional transmission network congestion, and the economic value of this congestion, is not transparent in the region-based NEM. There is currently no exposure to the cost of increased congestion on the common carriage network as a result of generator investment, and there is little information to indicate the impact of this congestion on local generation and load. This lack of transparent information about congestion means that new entrant generators may not consider the cost of transmission in their locational decisions.

There is already evidence of wind generation causing network congestion in the South Eastern, Eyre Peninsula and mid-north areas of South Australia. Congestion caused by Lake Bonney wind generators has led to constraints on the Heywood interconnector. In recent weeks, congestion in this area has caused 196 negative price dispatch intervals and counter-price flows have occurred where South Australia has imported energy across the Heywood interconnector, despite the price in South Australia being lower.

This highlights the growing need for comprehensive information about network capability to drive efficient augmentations by TNSPs and encourage efficient generator locational decisions. To ensure that the transmission network is utilised efficiently, VENCorp supports improvements to the pricing of congestion in the network. Possible options could include elements of the following:

- **Forward-Looking Information About Network Capability**
  This model would involve providing dynamic and transparent information about network capability, to inform generators' investment decisions and TNSPs' investment decisions. This information could be published dynamically on the AEMO website, and feed into a longer-term set of information in the NTNDP. This forward-looking information tool would complement the historic Congestion Information Resource to be published by NEMMCO.

[4] Executive Summary (ix), *AEMC Congestion Management Review*.

- **Generator Nodal Pricing**
  Generator nodal pricing would involve pricing nodes at which generation is located. As the AEMC noted in its Final Report of the *Congestion Management Review*, this would solve the 'dis-orderly bidding problem' that arises from congestion. However, any such model would need to be designed to take potential competition issues into account. The design would need to consider how many generator nodes should exist in each region, and ensure that particular generators do not gain strategic advantage.

- **Firm Access And Transparent Congestion Pricing In NTNDP**
  'Firm access' within the shared transmission network would provide generators with guaranteed network access. To maintain competition between generators, such physical firm access would need to be complemented by transparent and accessible information in the NTNDP about network capability or network constraints, and their price effects. Firm access in the shared network would be difficult to allocate and administer, especially as the network becomes more meshed. Further, it may not operate consistently with the common carriage transmission network.

- **Financial Rights**
  Network access for generators can also be managed with financial rights, similar to Financial Transmission Rights in some overseas markets such as the PJM. It would have to be investigated whether financial rights could operate effectively without allocated physical rights.

VENCorp would support the introduction of the first option, forward-looking information about network capability, as a positive first step in providing more information about congestion in the market. Such a model would provide a strong foundation to deal with challenges of network capability in the future.

ATTACHMENT 1 – RESPONSE TO AEMC QUESTIONS

ISSUE	QUESTION	MATERIALITY (LOW/MEDIUM/ HIGH)	VENCorp RESPONSE
1. Convergence of gas and electricity markets	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?	High	Without knowledge of the future carbon price, it is difficult to know what impact the CPRS will have on existing gas markets. However, VENCorp expects that gas and electricity markets will continue to converge. As a result, legislation and rules should, where appropriate, cover the "energy market" as a whole. This is happening gradually with the transfer of gas and electricity regulatory functions to the AER, the establishment of the AEMC, and the introduction on 1 July 2009 of the AEMO. While gas and electricity markets have developed at different paces, the gas industry is gradually incorporating mechanisms to improve transparency, cost-reflectivity and price-responsiveness. These include the establishment of the BB and the development of the STTM and the GSOO. VENCorp, in its capacity as the Victorian gas market operator, introduced five trading intervals into the Victorian wholesale gas market in 2007. This has resulted in increased cost-reflectivity and price-responsiveness. VENCorp would support further development of the gas market at a national level through. A sudden increase in gas-fired generation may place gas networks under increased pressure. For this reason, there may be a need in the future for a more strategic, long-term approach to gas planning in the context of climate change.
	What areas of difference between gas and electricity markets might be cause for concern and how material might the impacts of such differences be?	High	The most visible differences between the gas and electricity markets are the lack of near real-time pricing in gas, except for in Victoria, and price caps between gas and electricity. In the Victorian gas market, the current price cap for VoLL is $800/GJ. Developments in the STTM will improve the real time pricing in South Australia and NSW.

2. Generation capacity in the short term	What are the practical constraints limiting investment responses by the market?	Medium	Market participants and potential investors are facing uncertainty about the design of the CPRS and the specific carbon price. This uncertainty is being reflected in the financial market, in which futures contracts for electricity are not extending beyond 2012. **Market design** Market design needs to take these considerations into account. VENCorp is of the opinion that the current energy-only framework has delivered efficient outcomes to date, but there is scope to make improvements within this established framework. These improvements should include ensuring that the spot market price cap is appropriate. **The spot market price** One important factor of market design is to ensure that the spot market price cap accurately reflects the demand-side's willingness to reduce demand. If accurate, it should be high enough to attract new peak-demand generation investment. The price cap must also be set high enough to encourage further development and innovation of demand-side responses within the NEM. VENCorp's view is that the Reliability Panel must consider the new challenge that climate change presents to the NEM in its next review of the market price cap. Although the price cap is being raised to $12,500, the AEMC should consider whether this cap is sufficiently high to attract timely investment in the new carbon-constrained environment. The process for determining the price cap should also include analysis of the value that the demand-side places on losing load, as with the Value of Customer Reliability (VCR) in Victoria. Further discussion on the Electricity Market Design is in Section 3 of this submission.
	How material are these constraints, and are they transitional or enduring?	Medium	While material, uncertainty in the market will reduce as a specific carbon price or trajectory is set within the broader CPRS. The issue of an appropriate level of the price cap, however, is an enduring issue and one that must adapt with changing market circumstances.

3. Investing to meet reliability standards with increased use of renewables	How material is the risk of a reduction in reliability if there is a major increase in the level and proportion of intermittent generation?	High	An increase in the level of intermittent generation will add further pressure to the NEM, with a likely increase in dynamic constraints that may reduce reliability. VENCorp understands that initiatives, such as the semi-dispatch model, have been introduced to manage new wind generation in the NEM. . Further, the introduction of more wind energy in the NEM as a result of the RET will require equivalent back-up generation. The FCAS markets may need to be modified to ensure that they attract sufficient investment in back-up generation.
	What responses are likely to be most efficient in maintaining reliability?	High	**Improving investment signals for Ancillary Services** As wind energy can ramp up suddenly and uncontrollably, generation must be available to lower it through the 'raise' and 'lower' regulation FCAS. This back-up generation will need to be sourced from existing generation, or new generation that enters the energy market. This is because incentives available from the markets for ancillary services are on their own not enough to justify building new power plant. These incentives should come from energy market signals and carbon price signals. Capacity markets or payments would be a further distortion to these two incentive drivers. In VENCorp's view, the FCAS market design should be modified to recognise a change in the merit order dispatch of generation, to ensure continued secure and reliable supply. **Improving signals about network capability** VENCorp believes that the market needs improved signals of network capability to encourage generators to locate as efficiently as possible. As discussed in Section 5, VENCorp supports a model that provides dynamic and transparent information about network capability, to inform generators' investment decisions and TNSPs' investment decisions to meet reliability. This information could be published dynamically on the AEMO website, and feed into longer-term information in the NTNDP. This forward-looking information tool would complement the historic Congestion Information Resource to be published by NEMMCO.

5. Connecting new generators to energy networks	How material are the risks of decision-making being "skewed" because of differences in connection regimes between gas and electricity, and why?	Low	There is the potential for bias in generator locational decisions resulting from differences in charging frameworks between the electricity and gas transmission networks. For gas transmission networks, the generator must fund any new pipelines necessary to produce its gas. However, in doing so, the generator must generally obtain a contractual right to firm access for the expanded capacity. This is known as the 'contract carriage' approach. For electricity transmission networks, augmentations are funded either through the Regulatory Test or it is paid for by the generator. However, unlike gas networks, a generator who funds a shared network augmentation does not obtain any rights to the new transmission capacity. This difference in approach between electricity transmission and gas networks means that a new generator's locational decision may be skewed by the difference in gas and electricity connection regimes. However, a decision about the location of a generator is based on a multitude of considerations, including: access to a fuel source on a firm basis; transmission losses to the regional load; and expectations about regional wholesale electricity prices. It is therefore unlikely that the theoretical bias would in practice affect a generator location decision.
	How large is the coordination problem for new connections? How material are the inefficiencies from continuing with an approach based on bilateral negotiation?	Medium	As discussed in Section 5, the current NER do not encourage coordinated applications for connection to the network. As such, most applications for connection are negotiated bilaterally. This can be inefficient. VENCorp uses its own Connection Guidelines to fill this gap in the NER. If a provision is introduced into the NER to encourage coordinated connections, it must provide guidelines for dividing these costs between connecting generators.
	Are the rules for allocating costs and risks for new connections a barrier to entry, and why?	Medium	The cost allocation framework governing transmission network connection in the NER, in which generators pay shallow connection costs, may result in high costs for remote generation. This will depend on the location of generation in proximity to the shared network. VENCorp is of the view that the cost of any augmentation to the shared network

			to accommodate new remote renewable generation should be recoverable through the market benefits limb of the Regulatory Test. Following the introduction of the expanded RET and CPRS, it is expected that proponents will be able to input carbon prices and RECs into a cost-benefit analysis.
6. Augmenting networks and managing congestion	How material are the potential increases in the costs of managing congestion, and why?	High	The sudden entry of potentially large amounts of renewable electricity generation and gas-fired generation, driven by the RET and CPRS respectively, could significantly increase intra-regional transmission network congestion and congestion on interconnectors. As discussed in Section 5, high degrees of network congestion have the potential to lead to inefficient decision-making, while also reducing competition in the market. The entry of new wind generation has caused congestion in three parts of South Australia. Of particular note, the Lake Bonney wind generators have led to constraints being invoked on the Heywood interconnector. In recent weeks, congestion in this area has caused 196 negative price dispatch intervals and counter-price flows have occurred where South Australia has imported energy across the Heywood interconnector, despite the price in South Australia being lower. This inefficiency is expected to result in high costs to the market as a whole, unless there is an improvement in signalling network capability. Information on congestion can be provided by AEMO and the NTNDP.
	How material are the risks associated with continuing with an "open access" regime in the NEM?	High	The issue of physical "firm access" is a complex one, and one that should be considered in light of practical application and associated costs. The Commission should exercise caution before considering firm access for the shared network. Costs would be difficult to allocate, especially as the network becomes more meshed. Firm access may possibly be applied for connection assets but, again, there could be difficulty with allocating costs among generators. It may be possible to allocate financial rights to the network, distinct from physical rights. However, this would involve further consideration.
	How material are the risks of "contractual congestion"	Medium	The STTM will have a mechanism for shippers to efficiently trade pipeline

	in gas networks and how might they be managed?		capacity. This is not a problem in Victoria and the STTM mechanism should reduce the risk of contractual congestion in the other states.
8. Financing new energy investments	What factors will affect the level of private investment required in response to climate change policies?	High	The price at which carbon and RECs are set will be the key drivers behind any new private investment in Australia's gas and electricity markets. Depending on the price, the generation mix is expected to change considerably. As discussed in Section 3, the key factors that will affect the level of private investment include the market design, the effectiveness of market prices settings, and the role of a deep and liquid futures market in providing future prices signals for potential investors.
	What adjustments to market frameworks, if any, would be desirable to ensure this investment is forthcoming at least cost?	High	VENCorp endorses the NEM's current energy-only market design and is of the view that this model has provided efficient investment outcomes to date. As previously discussed in Section 3, VENCorp does not support capacity measures and believes that they would be counter-productive. There are a number of aspects of the current energy-only framework that can be improved, these are: • ensuring that the market price cap in the NEM is set appropriately to reflect preferences of demand, so that it can attract sufficient investment in turn; • DSR initiatives should be promoted. Raising the price cap would facilitate great DSR and encourage innovation; and, • ensuring that, through promotion and improved awareness of its role, the futures market remains deep and liquid and provides a strong future price signal for potential investors in the physical market.