Australian Geothermal
Energy Association Inc

Response to
Review of Energy Market Frameworks in light of Climate Change Policies Scoping Paper

14 November 2008

Executive Summary:

AGEA believes that geothermal energy, complemented with other renewable technologies including solar, wind and other emerging technologies, has the potential to represent a viable contribution and mitigation measure that will address the environmental and economic challenges of climate change.

Studies undertaken by the AGEA consultants McLennan Magasanik Associates (MMA), indicate the geothermal generation technology represents an economic long term renewable energy source that has potential to provide a reliable "dispatchable" and functional outcome consistent with the requirements of the NEM. Even if more conservative assumptions were applied regarding costs and learning rates, geothermal generation technology can provide for an economic long term renewable energy source.

Additionally, geothermal generation capacity can be developed in a range of geographic locations and will provide potential for a coordinated approach to Australia's long term energy requirements.

The AGEA have raised other issues relating to the interaction and linkage of issues from other related government policy forms to facilitate the holistic review of energy market frameworks.

We are of the view that gas will represent a transition fuel in a carbon constrained world. While Australian gas prices are considered low, on a world basis, in time Australian prices may have potential to assume parity with export pricing. In addition, increased gas consumption could have potential to further increase the cost of delivered energy.

The shift from coal fired generation technologies to gas fired generation technology will produce a lack of diversity in energy supply resources and may have potential for long term system security issues. In contrast, the establishment of geothermal generation capacity across Australia will provide for diversity of energy supply when compared to options involving the development and augmentation of gas supply systems.

The "most likely" development scenario will involve development of a "duplicated" energy delivery systems, in the form of large scale wind farms and gas turbine generation technology, and does not represent a capital efficient and reliable method of supplying Australia's medium to long term energy supply needs.

Presently, the existing regulatory arrangements do not make provisions for economic development of groups or clusters of generation capacity located in a particular area. The existing rules do not provide for a coordinated approach to least cost system development and does not always provide for efficient long term outcomes that are in the best interests of end use customers.

It is appropriate that consideration be given to other measures that will produce more efficient outcomes where potential exists to connect a number of generator proponents.

The AGEA propose that these transmission extensions be treated as traditional regulated assets, so that the risk of future generation development is shared across all customers in the same way as traditional network augmentations. This treatment would allow Network Service Providers to plan and construct assets efficiently and would provide for future connection options where generation capacity can reasonably be expected to occur.

The above outcomes could be achieved by developing a clear and practical economic test involving changes to the existing Regulatory Test (cost/benefit) that is currently used by Network Service Providers to assess the viability of regulated augmentations.

These outcomes could also be facilitated by appropriate inclusions in the existing "Contingent Projects" regime that provides for large and uncertain capital investments in electricity infrastructure. The inclusion of appropriate capital provisions for "Contingent Projects" is important and would facilitate the development of emerging projects that were not identified prior to the start of a Network Service Providers revenue assessment period.

In the case of interconnection augmentations, significant works may be required in one jurisdiction, but the benefits may accrue in a different jurisdiction. For the jurisdiction required to undertake the augmentations, customers will potentially incur increased TUOS charges but not be the direct beneficiaries of these capital works.

It is likely that CPRS policy will stimulate the need for interconnection augmentations. In order to produce an environment for efficient augmentation outcomes, existing regulatory arrangements will need to be changed to facilitate equitable cost recovery mechanisms between regions. This could be accomplished by the allocation of TUOS charges based on inter-regional transmission flows.

There is strong interest across all Australian governments in the potential of the Australian geothermal energy industry to assist in meeting future emissions reduction targets in recognition that geothermal energy is emission free, base-load and makes an important contribution to long term energy security goals.

In summary, appropriate consideration should be given to supporting the development of renewable energy sources that are able to provide for low cost, large scale base load generation capacity by modifying the existing Regulatory Test and making inclusions in the existing "Contingent Projects" regime.

Issue 0:
The Linkage of Reviews

The AGEA are of the view that consideration must be given to the coordination and linkage between various Australian Government policy forms to provide for robust functional outcomes and propose inclusion of the following issue.

The Australian Government is developing a range of policies and measures that aim to address environmental and economic challenges of climate change and to reduce greenhouse gas emissions. These policies will have a direct impact on energy markets. It is likely that the review of these policies will have far reaching consequences on the electricity and gas markets in all jurisdictions. The formulation of policies in one area of government may have potential for direct interaction on the policy formulation in other related areas.

Question 0A.
How is the review of energy market frameworks to be coordinated between government departments, managing other key policy issues, to meet the Australian Governments overarching objectives for carbon emission management?

Question 0B.
What initiatives will be deployed to ensure the efficient interaction and linkage of issues from other related government policy forms to facilitate the review of energy market frameworks?

Question 0C.
As part of this review, what steps will be taken to identify and communicate key issues and questions that may be of relevance to other policy forms and so ensure that key issues are not left unanswered?

Issue 1:
Convergence of gas and electricity markets

Climate change policies will mean a larger role for gas, but differences between gas and electricity markets may mean that the market response is inefficient.

Question 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?

Question 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?

The AGEA makes no response in relation to these questions.

The AGEA propose inclusion of the following questions.

Question 2A.
In Australia and internationally, gas is seen as a transition fuel to a carbon constrained world. Australian gas prices are considered low on a world basis. In time will Australian gas prices assume parity with export pricing?

Question 2B.
What will be the effect on delivered energy price (electricity and gas) of both an increase use and increased price of gas?

Issue 2:
Generation capacity in the short term

Climate Delays to generation investment due to current uncertainty on the future policy settings, and timescales required to commission new investment, could result in a transitional problem in respect of the adequacy of generation capacity.

Question 3.
What are the practical constraints limiting investment responses by the market?

The practical constraints associated that may act to limit investment in the short term are:

- *The existing rules do not provide for a regulatory framework that supports development of renewable energy projects other than wind technology;*
- *In the case of emerging generation technologies including geothermal energy the existing rules to not facilitate nor support economic incremental development of projects;*
- *The shift from coal fired generation technology to gas fired generation technology will produce a significant lack of diversity in energy supply resource and may have potential for long term system security issues;*
- *The existing regulatory arrangements do not make provisions for economic development of groups or clusters of generation capacity located in a particular area;*
- *With respect to transmission and distribution network connection, grandfathering of technical compliance issues means the cost of any network upgrades required could be borne by the generator proponent;*
- *In the case of gas turbine development, the ability to gain commercially viable gas contracts in a suitable time frame;*
- *The timely and economic connection to electricity networks that are not already congested; and*
- *The provision of appropriate government approvals that provide for economic development.*

Question 4.
How material are these constraints, and are they transitional or enduring?

The above constraints are material and represent potential for significant delays in developing generation capacity in the short to medium term.

With respect to renewable energy development, the existing regulatory provisions favour development of wind generation technology. The existing rules do not facilitate or make provision for the economic development of emerging generation technologies such as geothermal generation.

Based on the existing regulatory provisions, the "most likely" development scenario will involve development of "duplicated" energy delivery systems, in the form of large scale wind farms and gas turbine generation technology.

Studies undertaken by the AGEA consultants McLennan Magasanik Associates (MMA), indicate that geothermal generation technology represents an economic long term renewable energy source that has potential to provide a reliable, "dispatchable" and functional outcome consistent with the requirements of the NEM. (Refer to attached MMA report).

Additionally, geothermal generation capacity can be developed in a range of geographic locations and will provide potential for a co-ordinated approach to Australia's long term energy requirements.

The establishment of geothermal generation capacity across Australia will provide diversity of energy supply when compare to options involving the development and augmentation of gas supply systems.

Generally, the number of energy network augmentations that are scheduled for development are limited with respect to the potential for future demand and the changing dispatch arrangements. As the potential for constraint (in the short term) will depend on the co-ordination of gas and transmission supply infrastructure, capacity limitations may be more acute than previously anticipated.

The numerous State and Commonwealth government development acts may also have potential to cause significant delays in the approval of energy network developments and create potential for investment uncertainty.

The situation is likely to be exacerbated by delays associated with augmentations to key network infrastructure. Presently, regulated network projects may take between 5 – 10 years to establish new overhead transmission lines. An outcome of these delays may involve constraining dispatch of generation capacity or out of merit order generation capacity for long durations of time will have significant impact on the economic viability of new generation entrants.

In addition significant augmentation of the gas delivery system may be required to support increased demand and mitigate the potential for unscheduled outages of key gas infrastructure and prevent disruption to power system networks (e.g. Longford in Victoria and Varanus Island in Western Australia).

In summary, geothermal generation technology has potential to provide an efficient development option compared to a development scenario involving gas and wind technology provided that the existing regulatory framework is amended to facilitate a co-ordinated approach to Australia's long term energy requirements.

Question 5.
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?

As mentioned in our response to Question 4, the existing regulatory arrangements will most likely produce a development scenario involving gas fired generation technology and large scale wind farms.

This development scenario will lead to complex interactions between gas and electricity energy systems that will be exacerbated by large scale wind farm development that will produce new operating issue of a scale and type not identified before. The management of these adverse interactions may require pragmatic operating decisions or interventions that cannot be identified or readily costed at this time.

Any review of the energy market arrangements should provide for a holistic overview of development issues by modifying regulatory framework to support development of groups or clusters of generation capacity located in a particular area; recognising the need for diversity and security of energy supplies together with a long term focus on renewable energy projects other than wind technology.

Issue3:
Investing to meet reliability standards with increased use of renewables

If standards relating to the reliability of electricity supplies are going to continue to be met, then investment in intermittent generation (such as wind-farms) will need to be matched by investment in other forms of generation (or transmission) – to ensure that supplies are reliable when wind generation is unavailable. Existing market frameworks might not deliver investment in such "back up" capacity at an acceptable cost.

Question 6.
How material is the risk of a reduction in reliability if there is a major increase in the level and proportion of intermittent generation?

The increasing penetration of intermittent generation capacity, in the form of large scale wind farms, may cause rapid large magnitude variations in real power capacity even allowing for diversity effects. In turn these rapid changes in real power may equate to large system frequency excursions unless dispatch from other reliable generation sources is used to "cover" the deficit and restore power system equilibrium.

It is likely that the generation sources used to restore power system equilibrium will be in the form of gas turbine technology. These facilitates will also require associated gas pipeline infrastructure, having an appropriate level of redundancy to provide for secure operation under system normal and contingency operating conditions.

It should be recognised that this development scenario is extremely capital intensive as the management of system security will require significant "duplication" of energy supply systems (in the form of wind technology, gas turbine technology and associated gas infrastructure) all having marginal utilisation.

As the installed capacity of large scale wind farms increases, the scale and cost of managing system reliability will increase rapidly. It is likely that these costs will be none linear and the infrastructure required to support the ultimate 2020 carbon emission target may be prohibitive.

In summary, a development scenario involving large scale wind farms and gas fired generation will be operationally complex, capital intensive, due to the duplication of energy supply systems and be "operationally challenging" to provide for the reliability levels that industry and the community require.

Question 7.
What responses are likely to be most efficient in maintaining reliability?

It should be acknowledged that, the "most likely" development scenario will involve development of "duplicated" energy delivery systems, in the form of large scale wind farms and gas turbine generation technology, and does not represent a capital efficient and reliable method of supplying Australia's medium to long term energy supply needs.

While "semi-dispatch" arrangements have been implemented to limit potential excursions in key flow paths, these management systems have not been tested based on the scale of generation capacity anticipated. It is acknowledged that weather forecasting systems will improve the ability to predict wind farm production.

It is appropriate that consideration is given at this time to supporting the development of alternative non intermittent renewable energy sources that do not require the attendant "duplication" of energy infrastructure. While a number of technologies are able to deliver large scale renewable energy, geothermal technology is able to provide for scheduled base load capacity that is not intermittent in nature.

The AGEA commissioned McLennan Magasanik Associates Pty Ltd (MMA) to independently assess the business development plants of Australia's geothermal energy companies in order to estimate how much electricity and generation capacity the Australian geothermal industry expects to deploy by 2020 and at what price.

The key findings of the report include:

- *The emerging Australian Geothermal Energy Industry can be expected to provide at least 1,000 MW and potentially up to 2,200 MW of base-load capacity by 2020 into the National Electricity Market;*
- *That capacity potentially represents up to 40% of the governments 2020 Renewable Energy target of 45,000 GWh – the equivalent of the output of up to 6,000 MW of wind farms;*
- *An estimated $12b would be invested to develop 2,200 MW of installed capacity;*
- *The cost of generating electricity from geothermal resources is expected to move down the cost curve through to 2020 through learning, experience and economies of scale outcomes commencing at around $120/MWh at small scale (10 MW to 50 MW) and decreasing to around $80/MWh at large scale (300 MW or greater) by 2020;*
- *That price is expected to be lowest cost of any form of renewable energy; and*
- *Most of the capacity is expected to come from developments in SA with other states increasing their contribution toward the end of the 2020 period.*

The report highlights that the Australian geothermal energy industry has a potentially significant contribution to solving Australia's long term climate change challenges. The demonstrated potential of the industry to deliver the low cost, large scale base-load benefits of geothermal generation warrants serious consideration.

The support and development required to establish geothermal energy should be seen in the same context as that required for coal fired generation capacity in the 1960 and 1970s. The establishment of coal fired generation technology could not have occurred without over-arching government support that included the co-ordination of transmission infrastructure, technological engineering support and environmental development approvals.

Provided with a supportive and an appropriate regulatory framework, geothermal energy has the potential to provide large scale, reliable and emission free energy from diverse locations across Australia.

Issue 4:
Operating the system with increased intermittent generation

Climate change policies may require more flexible operation of thermal generation plant, and this may create technical challenges or inefficient market outcomes.

Question 8.
How material are the challenges to system operations following a major increase in intermittent generation?

As mentioned previously, the increased penetration of intermittent generation in the form of wind farm capacity will serve to exacerbate both interconnection transfer constraints and frequency control issues and drive the need for additional scheduled generating capacity.

For example, consultation and studies undertaken by SA's ESIPC, would indicate a material basis for concern if large scale wind farms continue to be developed in South Australia.

In the case of large islanded power systems, such as the SWIS in Western Australia, it is likely that the establishment of large scale wind farms will drive the need for more spinning reserve plant or fast start generation capacity to ensure secure operation of the power system.

In summary, a scenario involving continued development of large scale wind farms will have potential to produce material challenges to the secure and economic operation of Australia's power systems.

Question 9.
Are the existing tools available to system operators sufficient, and if not, why?

In 2008 changes were made to the National Electricity Rules to facilitate the central dispatch and integration of wind and other intermittent generation capacity.

As a general comment it is too early to comment on the effectiveness of these changes as many wind farm developments captured under these rules are currently in the process of being commissioned.

While these new measures seek to manage secure system operation under system normal and contingency operating conditions, it is appropriate that further consideration be given to islanded operating conditions. Under islanded operating conditions the management of system frequency may be extremely difficult and could lead to significant disconnection of customer load or collapse of the power system. These issues will become more pronounced as wind farm penetration increases and displaces scheduled generator units.

Although this scenario represents a low probability event, appropriate measures should be considered and developed to manage this issue.

The value of scheduled renewable generation capacity should also be seen in this context as they also offer credible frequency control capability.

Question 10.
How material is the risk to large scale intervention by system operators and why might such actions be ineffective or inefficient?

It should be recognised that changes made to the National Electricity Rules to facilitate the central dispatch and integration of wind generation technology recognised the potential for material risk to system security and established controls to negate these concerns.

As mentioned it is too early to comment on the effectiveness of the NER changes but it is likely that as installed wind farm capacity increases the ability of remaining on-line scheduled generation or fast start generation to mange rapid changes in real power is questionable .

The most viable method of managing real power variations caused by wind farm development is by increasing the level of spinning reserve capacity or increasing interconnection transfer capacity where appropriate. However, the cost of providing these services should be noted when comparing other scheduled renewable development options.

Question 11.
How material are the risks associated with the behaviour of existing generators, and why?

In order to provide economic returns for shareholders, existing scheduled generators may seek to increase their bid price in response to market displacement by wind generators. In spite of this potential outcome, the long term economic viability of some generator units may be questionable.

As the run-time for existing scheduled generating units diminishes, the reliability of these" displaced" units may become reduced. In time, the availability of these units may be questionable and may not be capable of providing the required generation support services.

Given this backdrop, the economic viability of investing in further generation capacity may also be questionable.

Issue 5:
Connecting new generators to energy networks

Differences between gas and electricity networks, and the reliance on bilateral negotiations over connection, means that the significant expansion of gas and electricity networks may not be delivered in a timely way or at an efficient level of cost.

Question 12.
How material are the risks of decision-making being "skewed" because of differences in connection regimes between gas and electricity, and why?

The majority of Australia's electricity transmission and distribution facilities are defined as regulated assets and provide a basis for open access and provides for the connection of generation capacity by many proponents. Generally, these electricity assets are interconnected to provide economic sharing of energy and provide for increased system reliability.

In contrast to this, Australia's gas pipelines are of regulated by competition rather than a regulator. Generally, these energy networks are unregulated and are not interconnected with one another for technical and commercial reasons. While access can be gained to these gas supply networks, often the residual capacity is limited (as a result of their original basis for economic development) and associated commercial term and conditions for supply may impact on the economic viability of generation connection.

In effect, Australia's development and operation of regulated electricity networks is mature compared to the equivalent gas networks.

While the connection issues for gas and electricity transmission and distribution facilities are similar, market operation can be influenced by parties connecting to one system and not the other. This may have potential to produce unexpected market outcomes.

Question 13.
How large is the coordination problem for new connections? How material are the inefficiencies from continuing with an approach based on bilateral negotiations?

The existing regulatory arrangements do not support efficient development outcomes in the case of groups of generator participants seeking connection but having differing project timelines.

Presently, extensions to the transmission or distribution networks are negotiated based on bilateral contracts. A typical outcome of these connection negotiations is that the first generator proponent will only *install sufficient connection assets to facilitate their immediate connection requirements in order to:*

- *Minimise total connection costs and ensure project viability; and*
- *Limits access opportunity to other generators and prevent erosion of allocated marginal loss factors (MLF) or distribution loss factors (DLF).*

Often the connection configurations that are deployed by generator proponents make limited or no provision for the supply of future customer load. In addition, the Network Service Providers are required to provide connection based on the least cost connection configuration that does not materially impinge on system security. A typical outcome is that the immediate network connection assets have limited extensibility in order to minimise total development costs.

Generally, these connection issues may result in the potential to compound and complicate existing network development issues.

The increasing penetration of wind farm development will most likely see a proliferation of these issues and create potential for increased inefficiency.

In summary, the existing rules do not provide for a co-ordinated approach to least cost system development and does not always provide for efficient long term outcomes that are in the best interest of end use customers.

It is appropriate that consideration be given to other measures that will produce more efficient outcomes where potential exists to connect a number of generator proponents.

A reasonable option would be to treat these transmission extensions as traditional regulated assets, so that the risk of future generation development is shared across all customers in the same way as traditional network augmentations. This treatment would allow Network Service Providers to plan and construct assets efficiently and would provide for future connection options where generation capacity can reasonably be expected to occur.

The above outcome could be achieved by developing a clear and practical economic test involving changes to the existing Regulatory Test (cost/benefit) that is currently used by Network Service Providers to assess the viability of regulated augmentations.

These outcomes could also be facilitated by appropriate inclusions in the existing "Contingent Projects" regime that provides for large and uncertain capital investments in electricity infrastructure. The inclusion of appropriate capital provisions for "Contingent Projects" is important and would facilitate the development of emerging projects that were not identified prior to the start of a Network Service Providers revenue assessment period.

Question 14.
Are the rules for allocating costs and risks for new connections a barrier to entry, and why?

As mentioned, the existing rules for allocating costs and risks for new connections do not always provide for reliable and economic development outcomes.

The National Electricity Rules provide a frame work of shallow connection cost for generator proponents. Generally, the generator proponent is required to fund the immediate cost associated with establishing network connection.

It is also recognised that deep network augmentations may be required to facilitate network connection or increase in network transfer capability to facilitate economic development of a generation project.

In relation to deep network augmentations that may be required to establish economic generation development, consideration should also be given by Network Service Providers to applying an amended version of the Regulatory Test (based on our response to question 13) together with the inclusion of appropriate "Contingent Projects".

On occasions, Network Service Providers own and operate network assets that do not comply with the current technical requirements of the National Electricity Rules. These shortcoming or deficiencies are covered under the National Electricity Rules by technical "grandfathering" provisions. These provisions are intended to provide for pragmatic outcomes and limit the costs associated with network development.

In the process of establishing network connection, these technical shortcomings or deficiencies are often encountered and associated with upgrade costs passed to the connecting generator by the Network Service Provider. It should be noted that the cost for required upgrade work can be substantial.

The view expressed by some Network Service Provider is that as these costs were not covered in their revenue assessment period they should be paid for by the connecting generator.

While there are two sides to this issue, the existing rules do not provide functional outcomes for end use customers.

It is proposed that issues also be addressed by appropriate inclusions in the existing "Contingent Projects" regime that would provide for appropriate network infrastructure upgrades associated with "grandfathering" provisions when triggered by generation connection.

Issue 6:
Augmenting networks and managing congestion

Climate change polices may result in higher levels of congestion on energy networks and there is a risk that congestion costs are not minimised, or that they create a significant risk for potential investors.

Question 15.
How material are the potential increases in the costs of managing congestion, and why?

The "most likely" development scenario, involving large scale wind farms complemented with gas fired generating plant, will over a period of time produce significant changes in traditional network flow patterns. The potential and extent for network constraints associated with this new dispatch scenario is uncertain and will depend on many factors.

In response to these constraints, Network Service Providers, will undertake initial augmentation studies and seek to include these works within the next revenue assessment period. It should also be acknowledged that in the case of some large augmentations involving overhead transmission lines, the Development Application process may create additional delays, increased development costs and combine to produce uncertain outcomes.

In summary, the time taken to develop new regulated transmission infrastructure may typically take 5 to 10 years assuming favourable Development Application outcomes.

Question 16.
How material are the risks associated with continuing with an 'open access' regime in the NEM?

The viability of continuing an 'open access' regime will depend on the ability of Network Service Providers to plan, co-ordinate and implement augmentations works in a timely way. It is likely that network planning concepts will need to be more flexible and able to respond to an evolving range of development outcomes. The degree of scenario planning that can be undertaken will be a significant factor influencing the levels of constraint that may be experienced.

In addition, the rate and concentration of new generation connection will also influence the degree of constraint that may be seen. The rate that new generation connects will be influenced by CPRS policy. Clearly, the risks of continuing with an 'open access' regime will also depend on the responsiveness of the regulatory frameworks to adapt to change as required.

As future generation dispatch patterns change, the regulatory framework that controls network investment will need to be made more flexible and be able to support pragmatic investment decisions.

Question 17.
How material are the risks of 'contractual congestion' in the gas networks – and how might they be managed?

The AGEA makes no response in relation to these question.

Question 18.
How material is the risk of inefficient investment in the shared network and why?

The existing regulatory framework does not facilitate the efficient development of interconnections between regions.

The costs of transmission network augmentations within a jurisdiction are levied as TUOS charges for customers in that jurisdiction.

In the case of interconnection augmentations, significant works may be required in one jurisdiction, but the benefits may accrue in a different jurisdiction. For the jurisdiction required to undertake the augmentations, customers will potentially incur increased TUOS charges but not be the direct beneficiaries of these capital works.

It is likely that CPRS policy will stimulate the need for interconnection augmentations. In order to produce an environment for efficient augmentation outcomes, existing regulatory arrangements will need to be changed to facilitate equitable cost recovery mechanisms between regions.

This could be accomplished by the allocation of TUOS charges based on inter-regional transmission flows.

Question 19.
How material is the risk of changing loss factors year-on-year?

It is likely that the allocation of loss factors will change over time and may depend on a number of factors including:

- *Changes to generator dispatch patterns;*
- *Connection of additional generation capacity;*
- *Connection of additional customer load; and*
- *Changes to the network configurations (augmentations).*

It is likely that establishment of CPRS will drive new investments and may produce substantial changes in assigned loss factors for some generator proponents.

In the case of affected generators or customer load, the Network Service Provider should be required to consider the application of the Regulatory Test to assess the viability of network augmentation to facilitate economic development outcomes.

This activity should be undertaken in a timely way that gives consideration to the approval and construction timeframes for large scale network augmentations.

Issue 7:
Retailing

Changes in the level of volatility of costs faced by retailers, combined with ongoing price regulation, may reduce the effectiveness of retail competition.

Question 20.
How material is the risk of an efficient retailer not being able to recover its costs, and why?

Question 21.
What factors will influence the availability and pricing of contracts in the short and medium term?

Question 22.
How material are the risks of unnecessarily disruptive market exit – and why?

The AGEA makes no response in relation to these questions.

Issue 8:
Financing New Energy Investment

Climate change policies will require large investment in renewable and non-renewable generation capacity – and in energy networks. Current market settings may result in risks which increase the cost (or reduce the availability) of debt and equity finance.

Question 23.
What factors will affect the level of private investment required in response to climate change policies?

As mentioned, it is likely that the establishment of CPRS is likely to stimulate the need for a number of large scale investments in energy supply networks. Provided that augmentations to these energy networks are undertaken in a timely manner and that the potential for constraint or network access is minimal then it is likely that private investment in energy supply infrastructure will continue.

In order for this to occur, changes must be made to the regulatory framework and in the application of the Regulatory Test.

With regard to our response to Question 13, the AGEA are of the view that transmission extensions should be treated as traditional regulated assets to provide for economic development of generation in remote regional locations and provide for future capacity growth.

Question 24.
What adjustments to market frameworks, if any, would be desirable to ensure this investment forthcoming at least cost?

The concept of capacity payments is strongly supported by the AGEA as this will drive efficient development of appropriate renewable technologies.

The establishment of a capacity payment scheme would provide for recognition of total capital costs associated with the "most likely" development scenario involving large scale wind farms and gas fired generation capacity.

The AGEA are of the view that such a scheme would recognise the economic benefits of scheduled renewable generation, in the form of geothermal energy, compared to other intermittent sources of renewable energy.

As the capacity factors associated with geothermal energy are likely to be in the order of 90% or greater, the technology will also provide for the efficient use of connecting transmission infrastructure when compared to wind energy with capacity factors of approximately 33%. In effect, as geothermal energy can be scheduled, potentially less network infrastructure is required to deliver the same level of energy compared to *an option involving a combination of wind power and gas fired generation.*

In summary, appropriate recognition should be given to renewable generation technologies that have potential to provide firm capacity and support efficient utilisation of limited network infrastructure.