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Introduction

Much of the discussion to date in relation to the changes that need to be addressed in the energy market are focussing on the large scale production and distribution of either gas or electricity and the future inter-relationship between the two markets as gas becomes a major fuel source for electricity production. Little attention has been paid to the fact that the current policies being considered by the Federal Government of a Carbon Pollution Reduction Scheme (CPRS) and revised Renewable Energy Target (RET) may see more generation at a local or embedded level, impacting on the distribution network level rather than the transmission network level.

This is true in both gas and electricity markets, with green building codes reward emission reductions within individual projects, forcing developers to install gas-fired cogeneration plant to achieve the necessary rating for the project.

Looking at renewable generation technologies, with the exception of geothermal generation, the majority of renewable energy projects will be less than 75MW, making it more appropriate for them to be embedded in the distribution network rather than the transmission network. The exception to the above will be any large scale solar thermal or wind farm projects, which will exceed the 75MW size.

The geothermal generation projects will create their own set of problems, as they will start relatively small, but will be constructed on a modular basis, building up to sizes equivalent to our existing coal and gas-fired plant. The current locations of proposed projects will make connection through to either distribution or transmission networks extremely difficult, particularly under the current payment structure for new grid connections.

The following comments are made taking into account the changing face of energy markets as noted above and have concentrated our comments on those areas relevant to our current research activities.

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?

During the planning phase of any large scale development sufficient resources are allocated to ensure infrastructure needs are addressed. This includes the location of power stations in close proximity to their primary fuel source, irrespective of whether they are fuelled by gas or coal. The same locational requirements are even more important for renewable generation technologies.

It is the capability of the gas markets to supply smaller embedded generators that needs to be addressed as the size of the market increases. This difference between electricity and gas markets is currently being recognised by those entities looking at cogeneration options, such as new commercial buildings that are utilising gas-fired cogeneration for air-conditioning and other building plant, such as lifts. These will impact directly on the need for high pressure gas delivery into high land density areas such as CBD's and business/industrial parks.

The introduction of gas-fired cogeneration plant is a trend that will continue due to the weighting placed on greenhouse gas (GHG) emissions in the Green Building Council of Australia's 'Green Star Rating Tools'. Under the Green Star Rating Tools for Office Design (Green Building Council of Australia 2008) a total of 29 points may be awarded for energy efficiency with 20 of these relating to GHG emissions. These are awarded on a sliding scale based on predicted emissions using a GHG coefficient (kg $CO_{2\text{-}e}$/annum) of 1.068 for total electricity consumption compared to 0.257 for total gas consumption. The use of cogeneration plant to generate electricity on site can significantly reduce the emission profile of a project.

Gas markets will need to ensure that infrastructure is able to deliver the necessary volume at the required pressure during the peak times required (normally from 7:00am to 7:00pm). In addition many cogeneration plants that will be utilising renewable fuel, such as solar thermal and wind will also rely upon gas as a reserve fuel. Whilst many of these projects may not be connected directly to the gas network, larger projects in highly intermittent areas will be seeking to do so, including solar thermal and wind farms supplying local communities.

Areas where additional infrastructure is required need to be identified now and rolled out as planned major land development and building construction projects are identified.

From the centralised electricity system perspective it is felt there is at present a need for proposed gas pipelines to be built quickly. One example we think about is the on-going issue with the PNG pipeline, we remember this pipeline being discussed at Queensland Power Conferences in the late 1990s. Coal Seam Methane gas turbines can of course be placed at the source of the gas, the issue is the distance to the high-voltage transmission system. Also, the output of the proposed Gladstone LNG Project is supposedly all for export. However, a projected falling demand for LNG because of the economic downturn may allow for the expansion of gas-fired generation in Central Queensland, either by new investment or retrofit to existing coal-fired plants.

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?

Recent costings undertaken by building developers have also identified that the pricing structures within the two markets can lead to material differences in the final product costs, dependent upon usage.

Whilst the Green Star rating system and proposed CPRS is the main drivers behind the push to utilise gas powered cogeneration systems, the differing market conditions are making planning difficult. The major difference is in the pricing for each fuel within the market, with electricity being charged based on actual usage, compared to gas pricing being set based upon a pre-agreed supply, with any additional gas use over and above that contracted for resulting in significant penalty pricing conditions. There is no reduction in the contract for any gas under the contract not utilised.

Similarly, if the gas use exceeds the contracted amount on a regular basis, contracts provide for the retailer to increase the contracted amount to guarantee supply. This higher amount than becomes the contracted amount and is charged to the customer irrespective of the level of future use.

The security of gas pipelines is another issue to be resolved. The threat of a terrorist strike to pipelines or even an accident (similar to that which occurred in June 2008 in Western Australia) can disrupt supplies for extended period and whilst this is also possible for high-voltage transmission lines gas might be a softer target. Additionally the testing of gas pipelines for leaks and explosive potential needs clarifying.

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

The major constraint within the market is the lack of knowledge over proposed legislative and regulative changes surrounding both the CPRS and revised RET. With the existing MRET scheme nearing the end of its operational period, many entities have been unwilling to invest in new capital works. Whilst the new schemes have been announced investors are waiting until they are able to determine the additional potential economic returns available under both of the above schemes before committing to new investment.

Discussions with plant construction companies have also indicated that there may be considerable delays in construction timetables due to significant development in India and China, utilising much of the current experienced technical workforce.

The AEMC has already recognised that there may be risks in achieving the reliability standard in the future if investment in new generation is delayed or does not occur (AEMC 2008). The availability of a highly trained workforce to meet demand on a timely basis is an issue that needs to be considered.

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

It is considered that the constraints are transitional, but will extend for a number of years after the policies are known as the number of possible contracts, particularly for current plant upgrades or new gas and renewable plants is expected to be large. In addition consideration has to be given to the replacement of existing coal-fired plants that are nearing the end of their useful life. This may significantly increase the amount of new capacity to be constructed if some plants cannot be effectively upgraded/maintained during this period of increased construction activity.

Those plants that are not able to proceed due to construction delays may be cancelled if current RET proposals limiting the scheme to a maximum of 15 years prevents completion and commissioning by the date required to meet economic viability targets.

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

System Operators such as NEMMCO (or AEMO from mid-2009) have needed to make interventions on events that impact on the market such as: advance notice of low reserve conditions, status of market systems, over-constrained dispatch, price adjustments, constraints, market directions, market interventions, market suspensions. These interventions can be small or large scale but it is believed that these interventions are to maintain the reliability and security of electricity supply. So whilst it maybe effective it may be inefficient because higher-cost generating units maybe bought online to satisfy demand (thereby negating an economically efficient least-cost dispatch method) which will drive up the spot price paid by wholesale pool customers. Having a hedged position may minimise the extent pool price increases due to interventions for some participants.

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 level of intermittent capacity that may exist on a network without effecting capacity, given current technology, can be up to 20% of total capacity. It should also be noted that should energy storage systems also be introduced, the effects of the intermittency would be minimal (Zahedi 2007).The current push for gas-fired generation plant, particularly in Queensland will further assist due to the short lead-in period required to vary output. Whilst gas is already considered a useful ‘peaking power’ generation technology, it can also be used to supplement intermittent renewable generation sources.

Whilst the scoping paper highlights the fact that where air conditioning may induce peak loads on hot days which are relatively still, these conditions would generally provide good generating conditions for PV and solar thermal generating plants. This highlights the need to ensure that distribution networks have a mix of both wind and solar thermal plants or that transmission networks will allow for the movement of electricity between different regions which should be encouraged to exploit those renewable resources that are most abundant in that region (Dodd 2008).

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

It is important that both transmission and distribution networks recognise the strengths (and weaknesses) of renewable energy resources and ensure that planning infrastructure will incorporate the use of these resources. More planning will be required by operators of gas-fired generating plant, which may be used as 'peaking plant' when the renewable resources are unable to generate sufficient power. (However as noted in point 23, investment for plant required for this purpose will be difficult to obtain.)

As noted in point 6 above, peak demand in many instances is related to hot still days and increased use of air conditioning. It is on these days where PV and solar thermal generation will be capable of supplying their maximum load, whilst little would be supplied by wind.

A current discussion paper on *Improving Sustainable Housing in Queensland* (Department of Infrastructure and Planning 2008) has raised the question as to compulsory PV installations when building floor area exceeds a given area. This will allow for many residential dwellings to meet their own 'peak demand' requirements. Similarly, a wider roll-out of solar hot water, which currently accounts for approximately 25-30% of residential dwellings electricity use, will also allow for greater management of resources during periods of peak demand.

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

Challenges to systems operations will be material if planning for intermittent generation does not start as soon as practically possible. Having a RET of 20%, with much of this to come from wind and solar in the short to medium term, will require changes to the current systems.

In many ways, wind and solar based systems will complement each other, as solar tends to operate more efficiently on hot still days, with wind generally associated with more adverse climatic conditions. This can be both efficient and effective if there are sufficient generating resources available of each renewable fuel type, together with sufficient back-up generating resources that can be brought on-line quickly, such as gas-fired technologies.

NEMMCO has recently established the 'Australian Wind Energy Forecasting System' in conjunction with the Australian Government (NEMMCO 2008b) with wind being the predominant intermittent generating resource currently utilised within the market. This will allow for more accurate forecasting of available generation for this source. Over the short to medium-term solar thermal technologies will also be extensively deployed within distribution networks. The availability of similar forecasting technologies for this fuel source needs to be investigated.

Consideration will also need to be given to planning in areas where both fuel generation options are being utilised. Whilst noted above that they may be complimentary, climatic conditions will arise where both are operating at maximum capacity. If all generating capacity is embedded in the distribution network, than planning will have to allow for a greater information flow between the two networks.

The overall reliability of systems operations will increase as the reliance on coal-fired plant decreases (through retirements) and new gas-fired plant is brought on-line. The problem that arises is whether investment will be forthcoming for new gas-fired plant that will only be utilised during periods that intermittent resources cannot meet their portion of anticipated demand.

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

Existing transmission and distribution networks have been established on the basis of one-way electricity flow. With the use of domestic PV, the current systems have been upgraded to allow for two way flow, but this is currently on a very small scale. As the uptake in these systems increases, particularly as many companies have been established to target whole community based installations, further investment in infrastructure is required. As noted in point 1, buildings and industrial parks are also looking at cogeneration options, which in the future, may also provide for export back into the electricity market. As the cost effectiveness of renewable technologies start to compete with gas options, an increase in the use of these technologies should be expected.

Similarly, as more and more intermittent generation is included within the network, tools will have to allow for greater fluctuations in both supply and demand. European markets have been utilising large scale intermittent generating capacity for some time. This would indicate that systems tools to manage such operations currently exist. Current operators will need to review this technology and ensure that current tools are upgraded to cope as new generating technology comes on-line.

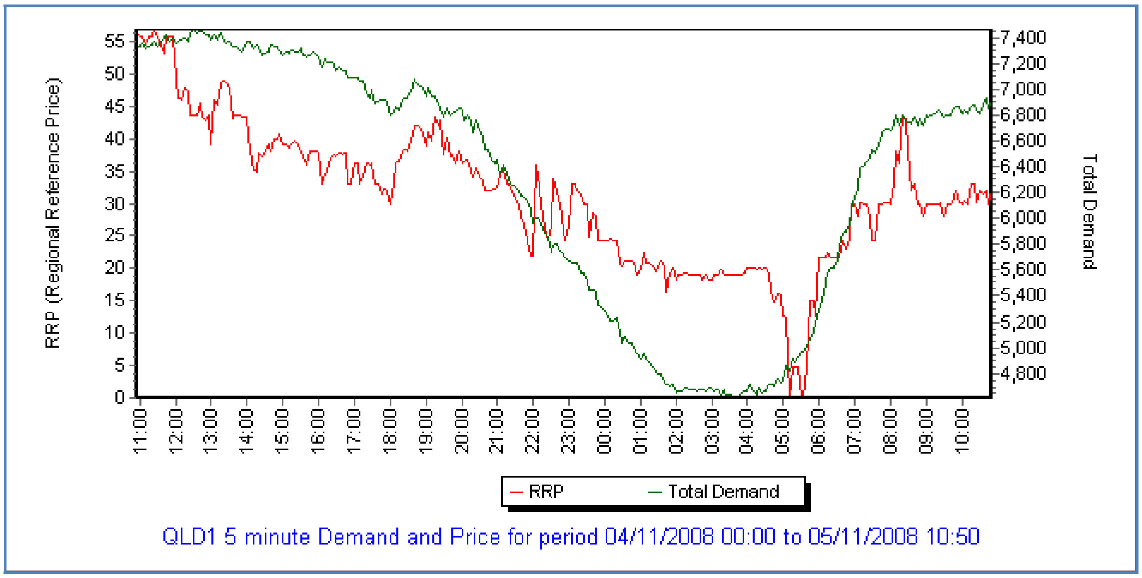
10. How material is the risk of large scale intervention by system operators and why might such actions be ineffective or inefficient?

No Comment

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

Existing generators will want to maximise revenue by supplying electricity during periods of peak demand. It will be the responsibility of the operators to ensure that sufficient scheduled resources are available and that those that have the capacity to hold back on supply do not do so. The daily price movements follow a similar daily pattern as shown below.

Figure 1 - Daily Electricity Demand and Price



Source: (NEMMCO 2008a)

At present all generators behave in a similar manner, with the gas-fired generators having the ability to increase or decrease generation significantly in the short-term, depending upon demand. Intermittent generators are limited by the fact that they can only generate electricity when climatic conditions are favourable.

This may result in a spot price being considerable lower during periods where no (or low) intermittent generation is available. Intermittent generation from solar based plants will occur during periods of both high demand and price. As part of the push for renewable plant, all generation should be dispatched at the prevailing price. The problem that arises is that this may cause an excess of supply which may result in both lower prices overall and less dispatch required from gas-fired 'peaking plant'.

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

The connection regimes of both electricity and gas are very similar, in that both require the user to pay for any costs associated with upgrading the system to accommodate their network connection. Based on discussions, large scale gas connections are currently less expensive than electricity connections, however, electricity is still an essential service that cannot be forgone in any development.

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

Co-ordination problems will arise as a large number of small generation sites (including both cogeneration and renewable technologies) try connecting to both electricity and gas grids. One of the major problems will be determining the needs of the area, particularly as the projected demand for services for the total area may exceed the services upgrade required for the new connection. This will require the continuation of the current approach of bilateral negotiation, ensuring that both current and future needs are addressed.

Whilst the CPRS will stimulate investment in gas-fired generation, there will also be significant renewable generation through the expanded RET. It is believed that the majority of these problems, due to the size of the generating plant, will impact upon distribution rather than transmission networks.

The scoping paper acknowledges that NEM participants must bear the initial cost of network upgrades to allow for their connection. In many future cases, with a number of renewable generators likely to evolve in a general location (due to high availability of resources), the upgrade required will initially be at the distribution level, with any upgrade at transmission level affecting only those who connect at some later stage (after any surplus capacity has already been utilised).

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

The costs for new entrants, particularly for electricity generators, are a major barrier for entry. As noted in the scoping paper, the areas that provide the greatest potential for renewable energy generation are located considerable distances from the existing grid. Generation through renewable resources should occur where those resources are most abundant and it was this same policy that has determined the location of most of our current fossil fuel based generation plant.

For the production of base-load power, the major potential source of renewable energy is geothermal, with the major resources and most advanced proposed demonstration plants being located approximately 2,000 kilometres from the nearest connection point to the grid. In addition, if the proposed level of generation possible is achieved (which would be some considerable time in the future, even based upon geothermal industry reports) the plant would need to be independently connected into each major capital city.

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

The management of congestion must include the dispatch of 'green energy' to meet both the needs of retailers and RET obligations. In the short-term, physical network constraints may lead to more output than is required by demand, however this will be overcome in the long-term as older fossil-fuel based plants are retired.

Community expectations will require that all 'green energy' is dispatched and utilised (at the prevailing spot price) to the fullest extent possible.

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

No Comment

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

Gas networks are managed based upon a pre-negotiated level of supply being available. Congestion will occur based upon network expansion not being able to keep pace with connection requests. This will be particularly true in CBD areas, where many building redevelopments are incorporating cogeneration facilities to meet 'Green Star' building requirements. This is a material problem that needs to be addressed as many of the gas networks in these areas are difficult to upgrade or provide for additional network infrastructure.

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

No Comment

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

No Comment

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

No Comment

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

No Comment

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

No Comment

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

One of the major drawbacks to private investment is the need to not only fund the generating plant project, but also the need to fund any additional infrastructure required to upgrade the transmission or distribution network to allow for the electricity generated to be dispatched.

For many renewable energy options (like fossil fuel options), the plant is established in areas where the greatest amount of fuel resources are available, which for renewable options the distance to existing network connection points may be significant, particularly as noted in point 14 above in relation to geothermal energy.

Similarly, the fact that a company provides for the infrastructure upgrade does not guarantee exclusive use of the asset, and will in fact subsidise future companies that need to connect to any point on this new transmission line. This is a penalty for taking early action which needs to be addressed.

Current planning provisions are also a major drawback for private investment. Most local government planning authorities have not given any consideration to the establishment of electricity generation plant within their boundaries. Much of the possible renewable energy plant will be less than 50MW capacity and particularly with solar thermal located close to the point of use, embedded in the distribution network. Planning issues need to be resolved to make planning and investment attractive by resolving development application approval issues.

As noted in figure 1, the times that renewable fuel sources are able to generate (with particular reference to solar) are the periods of high demand and price. Whilst this may prove to be an incentive for investors in this type of generation, it may also prove to be a disincentive for gas-fired plant, if it is primarily to be utilised for system reserves.

Finally, as noted earlier, the delays in finalising the CPRS and RET are not allowing private investors to fully determine the levels of economic return, therefore resulting in investors taking a cautionary 'wait and see' approach to investment. Private investors wishing to invest into fossil fuel plants (mainly gas turbines) will wish to know of the carbon price certainty in the initial period of the CPRS. The Final Garnaut Review Report (Garnaut, 2008) recommended fixing the price of carbon permits to $20 per tonne of $CO_{2\text{-}e}$ for the transition period (indexed for the period 2010-2012). This will provide some certainty for investors but after that market determined prices may see it rise to $40 per tonne or more, as reported recently in some mainstream media. If all permits are all auctioned (that is no free permits) right from the start of the CPRS, as recommended by Garnaut (2008), then investment in renewable forms of power generation maybe higher than expected.he relative price of gas to coal will be an important consideration for investment into new gas-fired plant. And the capital costs of fossil fuel technologies, especially if Carbon Capture and Storage (CCS) becomes feasible reality. The current push by the Rudd Federal Government to fund research and development into clean coal technologies may see commercial viability of CCS by 2020, whether existing newer coal-fired plants can be retrofitted may negate new investment in totally new coal-fired CCS plants.

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

To ensure that investment is forthcoming, some certainty in relation to any renewable energy being sold within the market is required. This could be in the form of a guarantee that all electricity generated from renewable resources will be dispatched at the prevailing market spot rate.

It is also noted that the AEMC has proposed a rule change to increase the 'Value of Lost Load' to provide the necessary price signal for new generating capacity investment (AEMC 2008).

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