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Discussion Paper: Annual WEM Report to the Minister
Attn: John Lillywhite
Economic Regulation Authority
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Dear John,

RE: Annual WEM Report to the Minister

Griffin Energy welcomes the opportunity to provide comment for the annual review of the WEM, as outlined in the discussion paper. As an integrated generator and retailer in the WA market; and as a current developer of significant generation capacity, Griffin holds an interest in ensuring the new market meets its objectives in a in the timely and efficient manner.

Griffin offers comment on the following discussion Points:

Discussion Point 1:

Fuel supply and fuel price plays a major role in any electricity market. Investment decisions are made on the availability and price of competing fuel types. Markets differ considerably around the world based on their peculiar attributes with regard to fuel supply. Putting renewable generation aside, the WA market has been built primarily on the availability of coal proximate to load centres (in Collie) and gas, available via very long pipelines connecting gas sources to the north of Perth. Each of these fuel types has specific physical attributes and constraints. These are well understood in the generation sector. The physical supply and price constraints of each fuel type form part of the economic investment decision making process. While unforseen, the reduced availability of gas and the rapid increase in gas prices in the last 2 to 3 years as a result of the expansion of the LNG sector, is part of the market driven risk profile of this fuel. These increases have materially affected Griffin's decisions regarding our current gas-fired generation developments. Similarly, while unfortunate, the recent Varanus Island incident is not probabilistically unexpected and again forms part of the risk profile of gas supply which should be factored into future investment decisions.

Constraints that are less well known, and hence create investment uncertainty, are those related to policy. Consider the current scenario in WA, where supply of gas to the South West is influenced by a number of policy related issues, such as the regulatory regime on the pipelines; the affects of exploration and production legislative parameters; and policies relating to reservation of gas supplies for the domestic market. Similarly, coal generation is affected by the considerable uncertainty of both state and federal policy relating to carbon emissions and the environmental approvals process. It is these constraints that lead to the greatest uncertainty when making investments decisions. Policy surrounding these issues should be transparent and made with the long-lived investments typified by the generation sector in mind, rather than by short term reactions to specific events. For example, government subsidised gas storage facilities close to load centres may materially alter competition between fuel types and impact on existing investment decisions by changing the supply equation.

With regard to the short term operation of the market and the affect of fuel supply constraints, Griffin believes that the most significant issue is that of diversity and security of supply; and the impact on the generation reserve margin. The reserve margin should reflect the high reliance in the SWIS on undiversified gas supplies.

<u>Discussion Point 3:</u>

The transmission system in the SWIS is operating near full capacity. Many new generation developments are reliant on an expansion of the existing transmission system. Large transmission augmentation projects will often have longer gestation and development timelines than generation developments; so there is a scenario in the SWIS where new generation developments are being held up by a lack of transmission capacity. Exacerbating this is the requirement for new generation developments to have a network access offer in order to obtain capacity credits[1]. This leads potential generation developers to seek network access very early in the development phase, which in turn leads to the formation of a 'queue' for access to the scarce transmission commodity. Often, projects occupying queue space, and hence valuable resources at Western Power, will not make it through to development. This creates time constraint problems for bone-fide projects which must compete for Western Power resources. This scenario may also lead to spurious network access applications being made on parts of the network that are seen as likely locations for future generation investments. A position on the transmission queue is not far removed from the rights afforded by an access arrangement; and subsequent abuse of these rights needs to be monitored[2]. Griffin believes that the lack of transparency around projects occupying queue space is unwarranted. Potential generators seeking access rights should be treated no differently than existing generators with access rights, that is information relating to the proponent, location and size of the proposed project should be known (information relating to technology type or other commercially sensitive information should not be made available – in keeping with normal confidentiality practice).

Griffin has direct experience with potential generation developments that have been delayed due to a lack of transmission capacity. In our opinion, much of this is due to the misalignment between the drivers for funding and procuring new transmission capacity and the constraints of the reserve capacity cycle.

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[1] The IMO is effectively outsourcing a key element of its obligation to ensure adequate generation capacity exists to a Western Power transmission planning and funding process that is not designed to meet this critical system obligation.

[2] Either the purposeful delaying of other projects on the queue through nefarious tactics, or the inadvertent delay of other projects through inadequate project development capability.

Discussion Point 4:

The risk that network connection will not be delivered on time is a development risk, similar to a projects own construction risk or equipment manufacturing risk. However, these risks are normally mitigated through liquidated damages clauses, negotiated between parties. Since disaggregation, Western Power has moved away from accepting liability for costs incurred through not meeting contracted deliverables such as late delivery. The lack of competition in this regulated monopoly market enables this position. Western Power's regulated return should account for the earnings of a competent and prudent network operator. This does not imply that the operator should be exempt of negotiated contractual risk.

Discussion Point 5:

Connection charges are a contentious issue. On one hand, it can be argued that generation investment responds to load growth, so that the cost of augmenting the transmission system should be borne by loads. On the other hand, there are locational signals associated with transmission costs. A captive coal deposit or geothermal resource hundreds of kilometres from a transmission connection point cannot expect the cost of that connection to be borne by loads, as this attribute forms a fundamental part of the economic cost of the generation plant (where the cost or capacity to relocate the fuel source must be weighed against the cost of transmitting the power).

Transmission systems for vertically integrated electricity utilities (which historically the SWIS has emerged from) have been developed over a long period of time and are designed around the most efficient compromise between generation location and power transmission. The objective of a disaggregated regulated network operator is for continued prudent investment in the transmission system which ensures adequate system capacity in a way that does not prejudice competing private generation interests. This is a balancing act that requires decisions on where and when to invest in the network. Just because a particular part of the network was not strengthened at a particular point in time does not mean that this was the most efficient use (or non-use) of transmission investment resources. Western Power itself admits that investment decisions are reactive, relying on information relating to future generation developments; and that their own reaction times often far out weight generation development timelines.

> *"Western Power relies on proponents to provide details of projects early enough to be incorporated in scenario planning. However, there are a range of factors that can change the feasibility, timing, size and location of such projects. Moreover, in some instances, proponents only provide details of their intentions once the projects are nearly committed, to minimise their commercial risk. Each of these factors will affect Western Power's ability to accommodate all new generation proposals in a timely and economically efficient manner. Western Power's planning process must manage the high levels of uncertainty associated with the timing, size and location of potential future generation sources. The impact of this uncertainty is increased by the time taken to complete major transmission network augmentation projects, such as the construction of 330 kV transmission lines. While the construction phase of a generation project can take as little as two years, establishing a new transmission line can take seven to 10 years from conception to commissioning."*[3]

[3] Western Power "2008 Transmission and Distribution Annual Planning Report"

Like a fuel source, the location of existing transmission assets (and in particular, existing connection points such as terminals), should act as a locational price signal for new generation investment. Generation proponents should expect as a minimum, that the existing transmission system will be maintained to a degree that enables new generation developments to connect to meet load growth demands.

Griffin's view is that generally, deep transmission connection costs should be smeared across loads when these costs relate to the augmentation of the existing transmission system (i.e. the network of high voltage transmission lines connecting existing or planned generation connection points with distribution points). In this way, new generators can confidently plan developments that connect to existing (or prudently planned) assets, knowing that they will incur the cost of connection to the existing transmission system, but will not be liable for additional augmentations.

Griffin believes that the process of determining network connection costs would be improved by more transparently describing the methodology used in attaining these costs.

Discussion Point 6:

The network planning process should be better integrated with the reserve capacity process to ensure that sufficient transmission access is available to new generation developments in a timely manner. This, coupled with a more transparent treatment of deep connection costs (as outlined above) should enable new generation investment to be made with more certainty.

Discussion Point 7:

Prima facie, the reserve capacity mechanism creates a disproportionate incentive for investment in low-capital cost plant. However the prejudice of the reserve capacity mechanism will always be counterbalanced to a degree by opportunistic investments made on comparative advantage. Griffin acknowledges that it is too early to interpret the pattern of new market entrants.

Generally speaking, Griffin believes the reserve capacity mechanism is too narrow to adequately cover the differing range of capacity types without introducing inefficient market distorting signals. While we advocate simplicity in the Market Rules where possible, this should not be in lieu of robust competition between capacity types. This concern is captured in some of the following comments.

Discussion Point 8:

The reserve capacity price does not provide an investment signal *per se*. If this were the case, the signal would be to invest in liquid fired OCGT plant with no gas connection and located somewhere on the network that incurred minimal connection costs[4]. As is mentioned in the discussion paper, the lack of a reserve capacity auction to date implies that all reserve capacity has been bilaterally traded. This suggests that the real reserve capacity price is a market price based on the capital cost of constructing the specific facility to which the reserve capacity is assigned.

Discussion Point 9:

[4] The 2010/11 IMO capacity price build does not include a gas lateral connection and only permits around \$20.7M of connection and deep augmentation costs.

The reserve capacity refund is designed to imitate the response of an energy-only gross pool market, where suppliers of hedge products are likely to be called during periods of peak demand. While peak demand in the SWIS is not necessarily linked to times of system capacity constraints (as the current Varanus Island incident highlights – where significant plant is unavailable for a variety of reasons), the design of the refunds are predicated on sound theory.

Of concern to Griffin is the affect of the capacity refund mechanism on new facilities. The capacity cycle encourages new facilities to enter operation at the beginning of the hot period, when capacity refund payments are high. This creates a situation where economically efficient planning of the construction of a new generator is impacted by the high penalties incurred if the construction of the facility falls behind schedule. To deliberately corral the entry of new facilities, when their capability to meet their long-term operating design capacities is vulnerable, into the period of highest demand and capacity price risk seems illogical.

Another inconsistency in the capacity refund mechanism is its bias toward penalising high capacity factor plant. Coal or CCGT facilities (or any other facility with a high capacity factor) are effectively 'on call' 24 hours a day (i.e. they are required to meet their maximum capacity obligations at all times). Outages or partial deratings are picked up and penalised at every occurrence, even if there is sufficient capacity in the market to meet demand. Low capacity factor facilities (liquid fuelled OCGT or DSM) can theoretically not be fully functional at their maximum reserve capacity for the majority of the year, but will not incur penalties unless called. Investment in high energy producing plant should not be penalised disproportionate to peaking plant. In effect, the reserve capacity mechanism is a proxy for the hedge products offered by peaking generators in a gross-pool, high VoLL market. If anything, it is these plants that should bear the brunt of capacity refunds, as they have been built specifically to meet capacity shortfalls during high-priced periods. Griffin would welcome a review of the application of the capacity refund system (acknowledging that a review has been conducted recently) that looked at the application of refunds levied at generators when system capacity is not at risk. Meeting the cost difference between the failed plant and the plant that is dispatched to meet the marginal supply caused by the failure might be a more appropriate mechanism.

Discussion Point 10:

Griffin does not believe there are significant benefits to changing the timing of STEM closure at this early stage of the market's development. There is insufficient volume traded in the STEM to warrant the potentially high costs of altering systems and processes to manage this.

Discussion Point 13:

The introduction of the expanded MRET target (20% by 2020) will have a significant impact on the amount of wind (and potentially other intermittent) generation on the transmission network. The MRET policy provides a direct consumer-pays subsidy for wind generation, in the order of $30/MWh - $40/MWh, or approximately double the historical cost of electricity produced in Australia. There are additional, indirect costs caused by intermittent generation, including increased standby generation, inefficient operation of existing (mostly base load) plant and the significant investment required to reconfigure a transmission system not designed to export energy from high wind resource areas. The allocation of these indirect costs is contentious. On the one hand, if they are smeared across all users (as most of them presently are), then intermittent generators receive significant subsidies beyond those provided by the MRET scheme. If they are to be borne by intermittent generators, then WA risks creating an environment where, relative to other jurisdictions, investors will be unwilling to pursue new renewable (intermittent) generation. While the second scenario might be considered the most economically efficient outcome[5], it is probably not a politically sustainable outcome.

The structure of the existing electricity system has been established over a long period of evolutionary development. It cannot be expected for this system to be radically altered without incurring significant costs. Griffin's view is that if it is politically and socially acceptable that new renewable (intermittent) generation is developed in WA, then the consequent higher cost of our electricity system should be borne by all users.

<u>Discussion Point 14:</u>

DSM should play an important role in any electricity market, especially a market with the characteristics of the SWIS, an isolated system with very high peak demand loads relative to latent and overnight loads. However, Griffin believes the capacity mechanism provides a sub-optimal structure for administering DSM. As stated previously, the capacity mechanism rewards investment in new capacity, providing a payment stream similar to those generated by providing derivative products in a gross-pool, high VoLL price market. DSM involves little (or no) investment. DSM is used as a last resort, generally when all system generation capacity is exhausted. The alternative to DSM would be rolling blackouts. It would seem more sensible to auction the right receive power at these times rather than pay, over the course of a year, for a potential load reduction at the time of system constraint. Auctioning the right to receive power might work by enabling those with the capability to do so to bid a price, up to a pre-determined cap, for which they are willing to reduce their load. Where it is economically efficient, loads will be reduced for monetary compensation. Loads will need to calculate the probabilistically weighted cost of not entering a DSM bid price (and potentially being turned down with no compensation) against entering a DSM bid price.

Structural changes to the Market Rules of this nature would take some time to implement. In the interim, the DSM working group has made sensible modifications to the existing treatment of DSM that at least requires DSM proponents to prove the capacity payments they receive throughout the year are backed by a legitimate resource. Introducing an appropriate refund regime has also made DSM more consistent with other types of capacity with which it competes. While an argument may be mounted that theses modifications to the rules will lead to less DSM in favour of generation capacity, especially in periods of high economic growth, this merely reflects efficient market signals.

<u>Discussion Point 15:</u>

Generally, Griffin believes the rule change process is conducted in a transparent and efficient manner. All markets continue to develop and change over time. This is especially true of new markets.

The Discussion Paper raises a number of issues relating to rule changes. These are:

- Timeliness: Griffin believes that issues around the timing of rule changes are being adequately addressed by the IMO.

[5] The SWIS is an isolated system characterized by a very long and lightly loaded transmission network, with wind resources at the extremities of this network, and a low overnight load. This creates a high cost environment for the development of significant intermittent generation resources.

- Conflicts: With regard to the IMO being both the rule administrator and enforcer, Griffin believes that this arrangement is prone to conflicts. While the 'I' in IMO stands for 'Independent', experience in other jurisdictions suggests that similar statutory bodies are not always immune from the interference of the political masters of the day.
- MAC: The MAC plays a vital role in streamlining the rule change process. It is important to have cross section of market participants involved in the evolution of the market. While it is natural for short-term vested interests to surface, as long as the market objectives are adhered to, then vested interests that are also in the interest of the market will prevail while others will not. Griffin believes the IMO performs the role of arbiter of the market objectives well.

<u>Discussion Point 17:</u>

The lack of price transparency is built into the design of a net-pool market. Unless this is changed to a gross-pool design, or until the STEM begins trading considerably more volume than it presently does, pricing signals will remain opaque.

<u>Discussion Point 18:</u>

The WEM is still dominated by the incumbent state owned generator and retailer and the vesting arrangements between them. While the WEM has been successful in attracting new generation investment (helped by constraints on the incumbents), new retail entry will be stymied as long as the current vesting and contestability arrangements are in place. The vesting arrangement is rolling off in a timely manner. Retail contestability is dependent on cost reflectivity. The recent announcement by the government that tariffs in the non-contestable market would only increase by 10% per year until cost reflectivity is reached has effectively delayed full retail contestability until well into the next decade. It is Griffin's view that this decision will substantially limit retail competition in the market and hence the effectiveness of the new market.

Griffin also points out that this incremental increase in tariffs is at odds with a future Emissions Trading Scheme, where the point of pricing carbon is to change consumer behaviour. Also, in a predominantly bilateral market, where price signals are not transparent, the lack of cost reflective pricing and/or an independent tariff regulator means that the cost of emissions will not be effectively passed through to consumers. This cost must be borne elsewhere in the electricity supply chain.

<u>Discussion Point 19:</u>

The Ministerial Directions to Verve and Synergy are integral to the continued investment in the generation sector (if not the retail sector, as alluded to above). Altering the present restrictions will substantially impact the investment environment. While this is a matter of government policy, such decisions should be made with a view to the long term impacts on the market (and not as short term responses to specific supply/demand shocks). Any change to this policy should be vigorously debated and implemented with long lead times, consistent with the investment profile of the generation sector.

<u>Discussion Point 20:</u>

As mentioned previously, it is necessary for all markets to evolve over time. It is sensible to introduce guidelines, regularly reviewed, that at least provide some forethought as to how the WEM might evolve; and perhaps more explicitly, provide a pathway to achieving certain goals along the way. The enthusiasm for market evolution however should be tempered with an acknowledgement of the physical constraints on the WEM. The cost and complexity of advanced electricity markets may simply not be appropriate for the SWIS. Griffin does not believe that, in the near term at least, the WEM should seek to move to a real-time market. In fact, the WEM might benefit from a simpler centralised dispatch and balancing mechanism, rather than pursuing the STEM route. Real market reform, however, can only come about with the dismantling and/or privatisation of the state owned incumbents. Without this step, the market will continue to be influenced by political rather than purely economic drivers, with the state owned incumbents constrained from acting in the efficient and rational manner which independent private ownership affords.

Griffin Energy will be happy to discuss our comments with the Authority and we look forward to the Authority's report to the Minister.

Yours sincerely,

Shane Cremin
Market Development Manager