Wholesale Electricity Market
Rule Change Proposal Submission Form

RC_2008_35 – Capacity Refund Mechanism – New Generators

Submitted by

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Submission

1. Please provide your views on the proposal, including any objections or suggested revisions.

Griffin is the instigator of Rule Change Proposal RC_2008_35. We also made a submission in the first submission period. As generation developers with direct experience in this issue; as well as holding significant retail operations in the WEM, we are disappointed in the way in which, what we believe to be logical arguments, have been assessed to date. Griffin believes that proposals such as this must be assess against the Market Objectives using a more realistic commercial framework rather than a rigid theoretical basis.

Griffin points out that if the commercial considerations of our unique market are not given due consideration when considering the impacts of Rules on the Market Objectives, then there is a very real chance that sub-optimal market outcomes will be achieved. At issue here is that the WA market is not the NEM. We are not a gross pool market where new costs may be efficiently passed through by generators. We are a bilateral market. This has two important implications. There is unlikely to be any new energy producing generation investment in our market based on merchant finance in the foreseeable future (pure capacity plays are the only way to finance a project without an off-take contract in the current market and even then, the variable annual administered price of capacity makes this a difficult proposition). Project finance for new entrant generators requires long term off-take contracts with creditworthy counterparties. This is especially evident at a time of very limited access to project finance, both locally and internationally. This leads us to the second important and related issue. Competition amongst new generators in a bilateral market will require point-in-time (static) investment decisions based on long term dynamic pricing variables. The contracted price required to make a return on any new investment is set, with the prevailing risk costs built into that price. Any additional costs added to the investment cannot be passed through (as an efficient price signal to consumers reflecting the true costs in the market – as is the case in the NEM) and are borne by the generator. This has the effect of eroding generator returns. A secondary effect will be the potential of diminishing returns through triggering project finance debt covenant ratios, further impacting equity returns.

Reliability

Rule changes that will theoretically better meet Market Objectives may have large flow-on implications in our market. In the case of RC_2008_35 (and RC_2007_08 before it), the IMO asserts that by applying cost penalties to generators in the form of expedited capacity refunds (note that the IMO consultant MMA similarly refer to capacity refunds as 'penalties'), the IMO will better incentivise generators to manage the risk of forced outage. Griffin's contention is that, while interval specific penalties may encourage a plant, at the margins, to make a commercial decision to remain on when the facility should rightly be shut down for maintenance, in the case of new entrant generators who are late in commissioning – and as a result are not available at any interval for extended periods of time, the refund mechanism provides little incentive[1].

Examine the incentives of 2 new facilities being brought online. The first, a capacity only facility – is designed to be available for peak demand periods and is what the whole capacity mechanism is built around. A rational investor would seek to maximise project revenue from its investment. As investors understand, revenue earned early in an assets life is prized more highly than the discounted value of revenue earned later. An investor would seek to begin earning capacity revenue at the earliest date, or 01 August. A peaking facility comprises commodity equipment. Turbines roll off manufacturing slots and construction timelines are reasonably fixed (though Force Majeure events and other unforeseen risks in construction, such as safety, environmental or significant IR issues are always possible). An investor might be risk averse enough to choose 01 October as a targeted start date (i.e. start the program 2 months later rather than extend its duration so as not to increase construction and interest costs). This would cover the possibility that the plant is delivered early (and revenue can be earned from day 1). This means that, under RC_2008_35, if a peaking facility were to be under an extended forced outage due to late commissioning long enough to reach the 'safety' of the seasonal caps, then it would be late by a period of nearly 4 months for the Dec/Jan cap and 6months for the Feb/March cap. In a real world setting, this relatively low capital cost project with relatively tight construction schedules (of around 15 months for a reasonably sized facility) will be around 25% and 40% behind schedule respectively. With no other revenue but capacity (it will not earn significant amounts through energy sales in a tightly price capped market), the large additional construction overrun costs and interest on construction costs *in addition to* the high burn rate of capacity refund payments will mean the project's financiers would be stepping in very quickly to either take control of an insolvent project or apply significant pressure for the owner to get the project commissioned. For a new entrant peaking generator, suggesting that they would be disincentivised to bring the facility online as quickly as possible whilst in the relative safety of the seasonal cap period is to not understand the dynamics of

[1] Anecdotally, Verve energy, with the largest generation fleet in the SWIS, experienced a forced outage rate in 2008 (under the revised capacity refund mechanism) of 5.3%, which is higher than it had recorded in previous years. This includes an outage to their flagship Collie A Power Station at a time of extremely high energy prices during the Varanus Island incident. Similarly, Newgen, with the newest commissioned facility on the SWIN, has experienced availability issues very recently at a time when STEM prices are above average and well above their SRMC. This indicates that the IMO's 'incentives' do little to incentivise generators in the face of many forced outages. Capacity is by nature not firm – though it is generally quite reliable. As in many applications, extracting a marginal unit of reliability at the top end of the reliability curve will often leads to exponential costs.

project finance and constructing of significant assets. The risk of reduced reliability to the market from a new entrant peaking facility due to the introduction of seasonal caps is immaterial, if it exists at all. In fact, the introduction of seasonal caps may just be the factor that reduces the cash burn rate of the project proponent enough for them, at 4 months and 6 months into a late project, to keep ownership of the project and remain a viable generator in the WEM.

On to the energy producing facility: Griffin has made it clear in its rule change proposal and its first submission that base load generators are greatly incentivised by bilateral contracts and the cost of meeting bilateral supply obligations with marginally priced electricity. Increasing a base load generator's expose to refund penalties introduces an additional cost that will either be borne by generators that have contracted prior to the introduction of the cost – reducing profitability and the generator's capacity to remain a strong participant in the market, or will be passed through to consumers in the case of new entrant generators that factor the additional risk cost into their contract pricing structure. Considering there is little or nothing gained by the market from the application of the additional cost burden, then it appears an inefficient cost.

<u>Market Costs</u>

The IMO's consultants, MMA, made much comment on how the capacity refund mechanism and the capacity market itself might be impacted by RC_2008_35. One of its points was that it believed that <u>if</u> there was a slight decrease in reliability (which Griffin rejects as per the arguments above), then there might be a slight increase in costs to customers from SRC. While MMA might be congratulated for having a good go at making a theoretical case out of such an arcane system stack up, Griffin cannot follow the logic of the arguments given the real commercial mechanisms of our market.

> *"Therefore delay of a 200 MW unit which represents about 4% of the installed capacity including embedded generation would cause unserved energy to increase from 0.002% to about 0.007%. This would increase customer costs by about $40M per year which is sufficient to fund 316 MW of peaking capacity at the Maximum Reserve Price of $127,500/MW/year. This does not include the cost of the lost low cost energy from the base load plant which could be worth some $37 M/year. This cost would be borne by the generator under the bilateral contract or by the customers for any uncontracted load that was to be supplied by the generator. The loss of capacity payments would be $25.5 M per year which would not fully compensate the customers." – MMA report, pg 27*
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> *"On this basis there does seem to be little impact in reimposing seasonal cost caps in the Refund Table to protect base load plant from excessive costs if the existing refunds would not provide adequate compensation and if any additional costs for Supplementary Reserve Capacity are going to be recovered under Rule Change 34." – MMA Report pg 28*

To begin with, capacity is a customer driven mechanism. Rather than rely on very high prices (representing the Value of Lost Load – or the price the marginal user is willing to bear before curtailing use), customers pay for the provision of capacity. As pointed out earlier, capacity in not 100% firm. It never will be, no matter how much redundancy a generator builds into their facility (at cost). This means that, statistically, there will always be a need for a mechanism such as SRC. The frequency of this event will depend partially on the price signals to make capacity available (as discussed, many other aspects incentivise availability) and greatly on the reserve margin employed. So customers must price in the impacts of SRC – just as retailers in the NEM price in VoLL incidences (and the hedging products used to mitigate these). Customers should not need to be 'compensated' for SRC by generators [note: Griffin will become the third largest Market Customer in the WEM in 2009]. This is akin to asking a generator in the NEM, which has sold a cap to a retailer, to then pay the difference to the retailer when the price exceeds the cap because their plant was unavailable and contributed to the higher price – when it is the generator itself that is required to be in the high priced market to meet its cap obligations to the customer. Not only is Griffin confused as to why generators should compensate customers for SRC costs (when the Refund Mechanism deals specifically with the non-supply of already contracted capacity for which the generator has been paid for and must refund – with a penalty cost to incentivise availability in certain intervals) but is somewhat disturbed that MMA refers to other costs being reallocated within the market to further compensate customers. MMA refers to RC_2008_34 as if it were a *fait accompli*. [note: RC_2008_34 is a greatly contentious rule change proposal that is receiving significant input from concerned stakeholders. It does not inspire Griffin with confidence that MMA is acting as arbiters at the upcoming workshop on this rule change proposal].

The next point is that of the 'increased customer costs' of SRC or unserved energy ($40M based on the MMA example[2] and which we contend should be factored into customer costs given capacity is never 100% firm). If we set aside any discussion on the value of unserved energy being set at $44/kWh (or $44,000/MWh – quadruple that of the NEM), we should consider the additional revenue earned by customers from generators over a 10 year period, where capacity refunds are incurred whilst there is a surfeit of capacity in the market – hence no additional capacity costs are incurred by customers. If we assume 5,146MW of certified reserve capacity in the market, and assume a forced outage rate of 5% (a typical historical figure for the SWIS in recent years based on a technical definition of outage – and does not include late commissioning or instances where plant is not meeting its Reserve Capacity Obligation Quantity – meaning this is likely to be a conservative estimate of actual forced outage rates in the WEM), then at $127,500/MW, over 10 years, customers will receive revenue equal to $328M, or around $33M per annum. So not only does Griffin contend that, like the NEM, unserved energy costs should be factored into a customers pricing structure, but customers already receive annual revenue from generators equivalent to this cost (and likely far greater than it considering the high value attached to unserved energy in these calculations).

Additional to this is the fact that, while customers will make some allowance in their pricing structure for expected SRC costs (admittedly a difficult task considering their volatile nature) on most occasions, this additional revenue earned from generators is not passed through to end users. Market customers seem to believe that under the customer driven capacity mechanism, retailers should be kept whole and not subject to risk while generators should bear the costs of unserved energy through capacity refunds; and end users, who are the ones eventually cut off from supply once the theoretical unserved energy price is breeched, should not be compensated for being so.

Lastly, the uncapped nature of SRC costs themselves seem out of step in an otherwise rigidly price (and behaviour) regulated market. At no point does the IMO or their consultants question whether the market benefits from allowing such a volatile event remain with the market.

Discrimination

Griffin contends that the capacity refund mechanism, as applied equally to base load and peaking plant (though not equally to all capacity, as the IMO contends, as its application to intermittent generation and DSM testify) is discriminatory. Quite simply, a refund mechanism designed to incur maximum penalties in a short time frame – as applied to all facilities, will naturally be biased against those facilities that are new entrants and subject to construction risks. Additionally, where the construction timeframe and task are longer and more involved than others, generators will face a higher probability of delay. This is not a controversial statement. Nuclear plant will be more likely

[2] I assume that MMA has applied the 0.005% reliability loss to approx. 16,400GWh of annual consumption and multiplied that by $44/kWh (which incidentally is 4 x the value of unserved energy in the NEM and highly questionable) to get $361M. Applied over a 10 year period for which SRC is due to occur once (at other times there is a surfeit of capacity) and an annual cost of $36.1M (or 'about $40M) is incurred.

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to incur higher refund costs than coal plant, which is less likely than new technology coal plant with carbon capture capability, which is much more risky than a simple OCGT etc. The IMO's consultant suggests that:

> *"It is generally known that base-load generators have higher capital and commissioning costs than more flexible peak load units, and that this higher cost is compensated for by lower operating costs that provides for significant inframarginal revenue at wholesale market prices. Indeed, this inframarginal revenue provides a major source of fixed cost recovery for these units, thereby providing an ongoing basis for recovering initial development costs." – MMA Report pg 42*

Inframarginal revenue at wholesale market prices? As discussed, in the WEM, a base load plant is bilaterally contracted. It does not rely on bidding SRMC in a market on the basis that, on average, wholesale prices will be at or above its LRMC so that it can make a return on its capital rather than just meet its variable costs (as in the NEM). While it is true that peaking plant, with no other material source of revenue other than capacity, will suffer greater financial disadvantage with a similar delay in commissioning, a similar delay is much less likely to occur. As such, we believe the concept of discrimination against more complex and capital intensive new entrant plant is valid. And in comparison to existing plant, which does not encounter one-off construction risk, new entrant plant of any variety is discriminated against.

One point raised by MMA is that:

> *"The impact of an unexpected shortage of base-load capacity could have a greater impact on the market than a delay affecting peaking capacity given that base-load plants are typically much larger, and by not being available, more expensive units will often be required for dispatch, causing price outcomes to be higher and more volatile. Should a Supplementary Reserve Capacity auction be required to address the shortage, the replacement capacity would not be expected to be equivalent to base-load capacity, thereby also raising potential capacity costs for end-users." – MMA Report pg 42*

This would suggest that base load capacity is valued more highly in the market. Griffin agrees, however the IMO insists that all capacity should be treated equally:

> *"The IMO contends that the Reserve Capacity Mechanism treats all types of generation equally." – IMO Draft Report, pg 16*[3]

<u>Other Issues</u>

Away from the arguments based on Objectives, Griffin is disappointed that the IMO did not investigate ways to improve the proposed rule change to better achieve the Market Objectives. The IMO has previously suggested amendments to rule change proposals where, in its opinion, make the proposal better achieve market objectives. Particularly, the IMO cites a specific reason for its decision to reject the proposal as:

> *"The proposed Amending Rules do not address the stated objective of recognising the unique risks faced by new entrant generators;" – IMO Draft Report, pg 23*

The proposal itself comprehensively addressed this issue, but the Amending Rules, as laid out in the proposal, were intentionally drafted to apply to all participants. This was discussed on several occasions in the MAC and the Working Group. It was made evident that a few simple alterations to

3 Griffin assumes that the reference to <u>all</u> does not include intermittent generation (or DSM)

the Amending Rules would have remedied the IMO's concern. It is disappointing that the IMO choose to make the concern a rationale for rejection on the balance of evidence rather than offer a simple redraft of the Amending Rules and removed it from the discussion.

In a similar fashion, the IMO has gone to lengths in its Draft Report to point out the lack of support the proposed rule change received. It also suggests that:

> *"The original rules had the support of industry, went through the public consultation process and the IMO consider are operating as intended" – IMO Draft Report, pg 23*

It has not qualified this however with the fact that considerable opposition to the existing refund mechanism has been expressed by other generators (including a significant submission by the largest generator in the SWIS – Verve Energy and a dissenting view in the Working Group by the other generation representative TransAlta). The fact that virtually all generators in the WEM oppose the existing refund mechanism and have some level of support for Griffin's proposed amendment should be noted – even if regrettably a lack of submissions did not certify[4].

The IMO also cites a rationale for rejecting the proposal as:

> *"There is no evident benefit to the entire market from amending the rules as proposed" – IMO Draft Report, pg 23*

Griffin contends that the 'entire market' is not required to benefit from rule changes – rather that the Market Objectives are better achieved. In fact, on this rationale, RC_2007_08 would surely have been rejected as a whole group of market participants – generators suffered as a result of its implementation.

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2. Please provide an assessment whether the change will better facilitate the achievement of the Market Objectives.

Griffin believes that a more significant reform of the WEM capacity market must be undertaken to better achieve the desired market outcomes, including incentivising timely investment in new capacity and ensuring a diverse mix of energy producing fuel types in line with system security objectives and mandated renewable and emissions legislation. It is buoyed at least by the IMO's commitment to this process

Based on the current mechanism, <u>on balance</u> (rather than in it entirety), the rule change proposal should better achieve the market objectives.

(a) Decreasing regulatory (risk) costs for no (or negligible) decrease in the safe and/or reliable production and supply of electricity is economically efficient, so this objective is, on balance, better achieved under the rule change proposal

(b) There is a marginal effect under this objective where the most competitive energy markets are those with the most appropriate mix of generation types. New generators, whether competing against each other or against existing generators, that suffer a competitive disadvantage due to inefficient or discriminatory price signals which affords a

[4] Anecdotally, recent discussions with many WEM stakeholders has revealed a complete loss of faith in the rule change process – to the point where making submissions is seen as a pointless exercise. Griffin itself has decided not to lodge prepared submissions on the basis that it did not deem it had a representative voice in the discussion. This worrying aspect of the regulatory change process should be addressed by the IMO promptly.

competitive advantage when bidding for contracts to a less efficient generator) may lead to a lessening of competition in the market.

(c) New entrant generation, especially those more likely to incur extended forced outage refund costs through late commissioning (i.e. capital intensive plant or new technology) is clearly discriminated against under the current refund mechanism, universally applied to all scheduled generators. The proposed rule change mitigates some of this discrimination.

(d) Griffin contends that, the cost of wholesale electricity will be reduced under the rule change proposal.

(e) Not applicable.

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3. Please indicate if the proposed change will have any implications for your organisation (for example changes to your IT or business systems) and any costs involved in implementing these changes.

As a developer of significant generation facilities, this proposal will lead to lower risk related development costs.

As a retailer, this proposal will likely reduce (non-forecast) income via the capacity refund mechanism settlement process.

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4. Please indicate the time required for your organisation to implement the change, should it be accepted as proposed.

Not applicable.
