Report to

Independent Market Operator of Western Australia

Rule Change #35 Reimposition of Seasonal Caps on Capacity Payment Refunds

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1 INTRODUCTION

McLennan Magasanik Associates (MMA) has been invited by IMO to review the proposal for Rule Change 35 which reintroduces seasonal caps on the refunds of capacity payments. The purpose of this change is to smooth out the refund of Capacity Payments in the event of an outage of extended duration or a delay to commissioning new plant. This Rule Change is intended to reduce the financial risks to which new entrant generators are exposed to be more in line with the costs incurred in managing those risks so that the efficiency of the market is enhanced.

There is some debate as to whether the Rule Change will advance the Market Objectives and would increase the perception of instability in the governance of the Market. This report presents the case as put by Griffin Energy (Griffin), discusses the views put forward by four respondents and offers MMA's view of what is required.

The following sections 1.1 to 1.4 of this Chapter are an edited version of the summary provided in the IMO Amended Rule Change Notice for Rule Change 35. The discussion reflects Griffin's view of the issues at stake and the need to amend the Rules. It does not necessarily represent the views of IMO or MMA.

1.1 Overview

Section 4.26 of the Market Rules deals with the calculation of capacity refunds applied to Participants that do not meet their Reserve Capacity Obligations. The intent of this section is to provide an appropriate incentive to Market Participants to ensure they are able to meet their capacity obligations; or to ensure that their capacity is available at times when it is most required. The Refund Table (as part of the overall capacity systems itself) attempts to codify in one application a catch-all for all types of capacity and scenarios of loss of available capacity. Importantly, the Refund Table makes no distinction between existing generators and new entrant generators. New entrant generators have a very different risk profile to existing generators because their early availability is critically dependent on a complex and costly construction process. This risk is managed by building in spare time and resources into the construction program to maximise the probability of meeting the required service date.

In 2007, a Reserve Capacity Refund Mechanism Working Group (the Working Group) was constituted to assess the drivers of the Reserve Capacity Refund Mechanism and to develop a more permanent solution to the Refund Table. The Working Group consisted of:

- IMO;
- System Management;
- Alinta;
- Verve;

- Synergy;
- Premier Power;
- TransAlta; and
- Perth Energy.

At this time, there were three major new entrant generation construction projects underway;

- Alinta's Wagerup OCGT (near completion);
- NewGen's Kwinana CCGT; and
- Griffin's Bluewaters Unit 1 coal fired power station.

Neither NewGen nor Griffin, both constructing new capital intensive generation plant, were included on the Working Group. NewGen and Griffin were also not represented on the Market Advisory Committee (MAC) at this time. Griffin believes that adequate consideration was not given to new entrant generators when developing the current Refund Table. It is Griffin's position that new entrant generators face excessive risks that lead to outcomes that are contrary to the Market Objectives. The details of these outcomes are set out elsewhere in this proposal.

1.2 Aligning the Refund Table with the intent of Section 4.26

Griffin believes that this clause in its present form, which has been changed several times in the past[1], does not strike an appropriate balance between being an efficient incentive and a being a punitive penalty, especially for the specific subgroup of facilities that are new entrant generators.

As an efficient incentive, capacity refunds are a useful mechanism to encourage Market Participants to manage their generation plant in a manner which optimises availability during times of peak demand. When the balance is skewed toward being a punitive measure, its usefulness as an incentive is diminished. A rational Participant will reach a point where additional costs will not impact its behaviour, as all reasonable measures would have been adopted at a lower cost threshold (in fact additional costs will reduce a participants financial ability to respond). This leads to an increase in inefficient costs to the market (i.e. generators internalise the risk of activating the penalty, which is passed through to consumers as higher wholesale costs[2][2]). Put simply, the market experiences higher costs for little or no benefit to reliability. This is clearly inefficient and contrary to the objectives of the electricity market.

This inefficiency is particularly apparent to new entrant generators. New entrant generators have a far greater likelihood of experiencing extended 'outages' in the form of

[1] Including, importantly, significant changes being made subsequent to Griffin relying upon the previous regime when negotiating and agreeing the damages regime applicable under its EPC contract for the construction of Bluewaters Unit 1 power station.

[2] See Exhibit 1-1 on pricing the risk of capacity payment refunds

construction delays, leading to the repayment of capacity refunds much more quickly during the Hot season (when the capacity obligations of new entrant generators begin). This comes about due to the removal of the concept of seasonal caps. Seasonal caps protect generators that are unable to meet their Reserve Capacity Obligations from refunding their entire annual capacity payment stream in what can potentially be a very short time frame. Additionally, since there is little incentive to maintain availability once the maximum refund limit has been reached (with peaking facilities), then system reliability may be compromised in the later seasons.

New generation plant is characterised by a very different risk profile than that of existing plant. New entrant plant is susceptible to one-off construction risk where the time frame for completing commissioning can blow out for extended periods for reasons beyond the control of the generator. This is especially so with generation types characterised by higher and more complex capital requirements with longer less controllable lead times[3]. This has the effect, contrary to the market objectives, of discriminating against particular energy options and technologies. Construction delay is often out of the control of Participants (and increasing penalties to generators still under construction actually reduces the financial capacity of the Proponent to expedite the construction process). With the Market Rules not recognising this issue (or the concept of Force Majeure[4]), it can be expected that new generation costs will include provisions for such potential significant penalties. Griffin believes that the re-introduction of seasonal caps is important to prevent unnecessary and inefficient potential penalties to new entrant generators.

This is not inconsistent with previous versions of the Rules. The Refund Table in Section 4.26 in the original version of the Rules contained a provision for daily and seasonal caps. The next incarnation of this table, from the EIRU, modified these caps (before reverting to the original version on review by the Office of Energy)[5]. The remit for the IMO to again review this issue came with the specific direction from the Office of Energy that:

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[3] The capacity refund mechanism; and the whole capacity market itself is a poor mechanism to deal effectively with differing types of capacity. In this instance, the difference between new entrant generators is stark. An aero-derivative OCGT can be constructed in around 6-9 months using a labour force of between 50 and 100, with much of the components arriving at site prefabricated elsewhere. A large coal fired power station can take between 3-4 years to construct, and require a labour force of over 600 at any one time. It is very obvious that these types of projects present different construction risk profiles, yet are dealt with using the same set of rules – a set of rules which is based on the dynamics of constructing an OCGT power station.

[4] The new entrant Participant is subject to the normal force majeure from contractors and suppliers but has no force majeure recourse under the market rules. This means legitimate construction delays cannot be cited as a reason for lateness. This increases the risk to new participants thereby restricting new entrants and adding to costs. Also, this provision may increase the leverage of construction labour and others, where in dispute with the baseload proponent, which may add to delays and increase costs.

[5] There have been interpretational discrepancies with the previous wording of the rules around capacity refunds. These have revolved around the use of the terms 'average' and 'maximum' refunds. Griffin points out that for new entrant generators, where the outage is due to construction delay, the total expected capacity of the facility is likely to be affected for all intervals, so the distinction between average and maximum becomes irrelevant. This highlights the excessive nature that capacity refunds designed to incentivise reliability can have on new entrant generators.

*"The Market Advisory Committee will be asked to consult with industry and to develop a solution to the issues with Rules that relate to Capacity Cost Refunds that were identified by the IMO in developing its IT Systems, and to ensure that these Rules achieve their intent **without being unduly harsh on any single Market Participant or group of Market Participants**."* – OOE Rule change report

Griffin submits, on the basis of the arguments above, that this proviso requirement of the Rules has not been met. The current rule discriminates against and presents greater potential risks to new entrant plant over existing plant – and especially so over new entrant plant with high fixed capital cost and construction requirements.

Griffin also submits that the purpose of capacity credit refunds is to incentivise reliability and availability. While this may be effective for peaking generation, which has little other incentive to maintain availability, base load generators are less inclined to see these penalties as their main driver for availability. Base load generators are financed on their long term off-take agreements, or their ability to sell large quantities of energy into a liquid market. Capacity payment revenue, or the arbitrary value placed on capacity under the mechanism which sets the Maximum Reserve Capacity Price, is not a consideration when setting prices through bilateral contracts.

These prices comprise the Long Run Marginal Cost of producing electricity, or as a bundled price, comprising the fixed capital and operating cost and the variable operating cost. Capacity payments, based on the fixed capital costs of a liquid fired OCGT, bear no relevance to the fixed costs of a base load generator. Capacity payments merely form a 'settlements loop' where they are transferred from retailers to generators via the IMO (while capacity itself, as an arbitrary component of the bundled electricity and essentially an abstract financial instrument created and controlled by the IMO, is in return transferred to the retailer). A far bigger incentive (and potential cost) to a base load generator is the requirement for it to meet its (often) substantive contracted supply obligations using the marginal price of energy being produced in the market. It can be readily assumed that this marginal unit of energy will cost considerably more to produce than the base load energy it is replacing. This means that allocating higher capacity refund penalties to base load generators, especially new entrant generators, is simply adding further risks and costs that do little, if anything, to incentivise reliability and which will ultimately be passed through to consumers.

Costs that discriminate against base load and mid merit generators do so at the expense of market efficiency. An efficient market is one that optimises the mix of generation types.

Regulation that alters the incentive to invest in the optimal generation mix leads to a reduction in market efficiency.

1.3 Proposed amendments

Griffin supports the re-introduction of seasonal caps while maintaining the price signals developed under the significant MAC sub-group review of the refund mechanism. In this way, the original balance between providing efficient incentives for availability (without being *unduly harsh* on specific Participants – especially new entrant generators), can coexist with the more appropriate interval-specific signals adopted by the MAC sub-group. The seasonal caps proposed are adapted from the caps used in the original Market Rules, as shown in Table 1-1, where Y represented the annual maximum refund possible under the rules[6].

Table 1-1 Original seasonal caps for Capacity Payment Refunds

Season	Cold	Intermediate	Hot
Maximum Seasonal Rate ($ per maximum Trading Interval MW shortfall)	0.3 x Y	0.1 x Y	0.6 x Y

In order to differentiate Y (as it currently applies in the Refund Table) Griffin has suggested in its proposed amendment that the annual maximum refund concept is denoted as "A" (see below).

This equated to a cap of 30% of the annual maximum capacity refund applying to the cold season; a cap of 10% of the annual maximum capacity refund applying to the intermediate season; and a cap of 60% of the annual maximum capacity refund applying to the hot season.

As the Hot season was split into a Hot and a Peak season by the MAC sub-group, the following has been proposed by IMO as shown in Table 1-2.

Table 1-2 Original seasonal caps for Capacity Payment Refunds

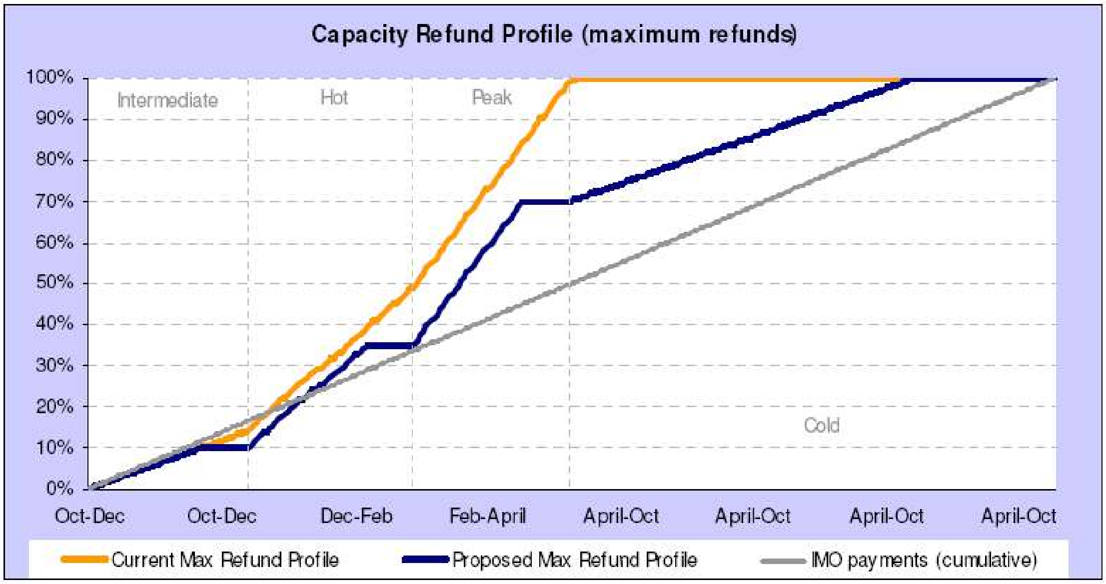
Season	Cold	Intermediate	Hot	Peak
Maximum Seasonal Rate ($ per maximum Trading Interval MW shortfall)	0.3 x Y	0.1 x Y	0.25 x Y	0.35 x Y

Adding seasonal caps (without the daily caps) has the effect of enforcing refunds up to a predetermined cap in each season and increases the timeframe for which Participants refund up to their maximum amount (i.e. the Maximum Applicable Refund – if applicable) without inhibiting the interval-specific signals applied to shorter duration outages. Griffin believes that implementing this methodology should not pose significant issues to the IT systems and monthly settlement processes.

Figure 1-1 below compares the proposed refund profile with the current refund profile for Participants that are unable to meet their capacity obligations for the whole year (i.e. the worst case scenario when the outage occurs at the beginning of the Capacity Cycle).

[6] This was not immediately apparent in the original Market Rules.

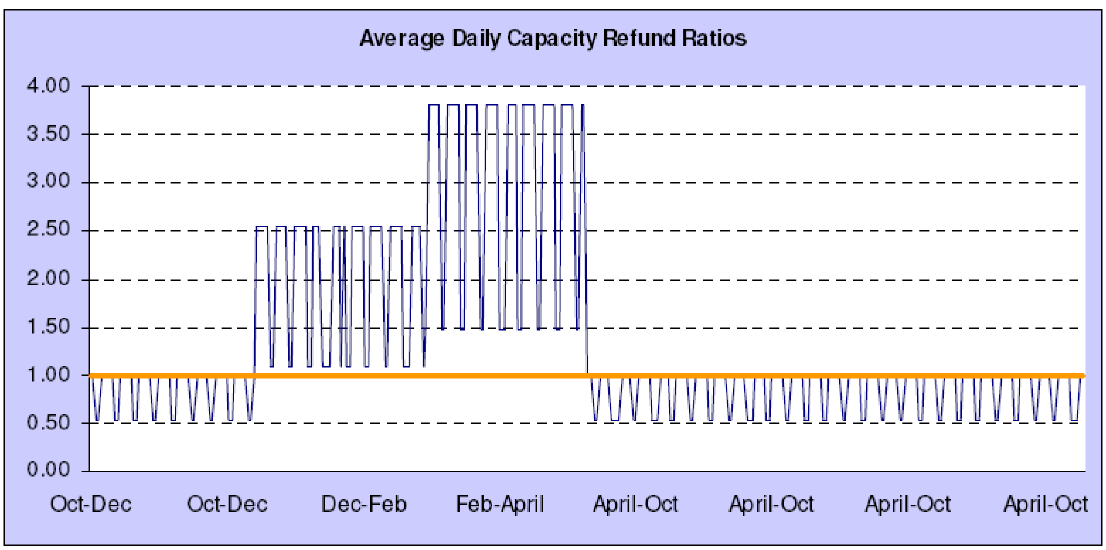
Figure 1-1 Capacity refund profiles



Source: Griffin Energy Rule Change Request 14th November 2008

Figure 1-2 shows the average daily refunds (of a long-term outage) as a ratio of capacity payments. The daily refunds are weighted over peak and non peak intervals and differentiated by business and non-business days.

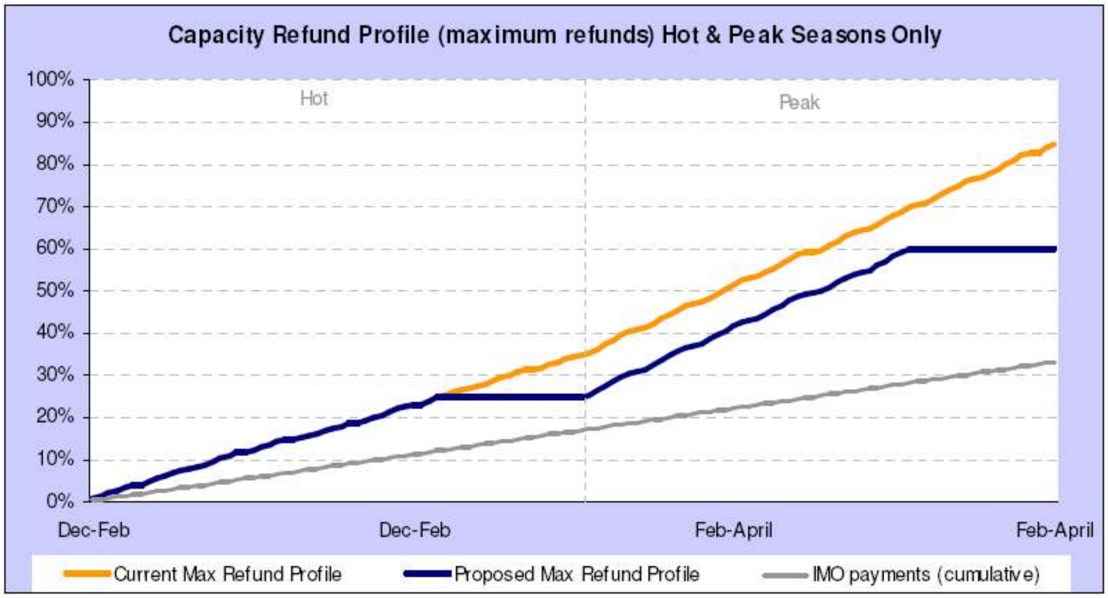
Figure 1-2 Average daily capacity refund ratios



Source: Griffin Energy Rule Change Request 14th November 2008

Figure 1-3 compares the proposed refund profile with the current refund profile for Participants that are unable to meet their capacity obligations for the Hot and Peak seasons only. This is when new entrant generators that have experienced delays are expected to begin their capacity obligations. For an existing generator that is on a long term outage from the start of the capacity year (1st October), there is a small surplus of

Figure 1-3 Hot and Peak season capacity refund profiles



Source: Griffin Energy Rule Change Request 14th November 2008

payments to refunds (i.e. a net benefit) throughout the Intermediate season (see Figure 1-1: Oct-Dec). This is not available to new entrant generators. Figure 1-3 clearly shows that new entrant generators are immediately exposed to high penalties. Griffin suggests that the 'Proposed Refund Profile' (blue line):

- represents an efficient incentive regime;
- is consistent with the intent of the Market Rules; and
- meets the Office of Energy caveat of not being unduly harsh on any single Market Participant or group of Market Participants.

The area between the 'Proposed Refund Profile' (blue line) and the 'Current Refund Profile' (orange line – and the area above the orange line) is claimed by Griffin to be an inefficient cost that will be passed through to consumers as higher long-term wholesale electricity prices. This is manifestly inconsistent with the Market Objectives.

Exhibit 1-1 Pricing the risk of capacity payment refunds

In a bilateral energy market, to finance the construction of an energy producing generator (rather than a reserve margin generator which relies on payments for making capacity available), a developer must be able to bilaterally contract the output of the facility on the basis of its Long Run Marginal Cost – comprising the energy and the capacity. How the output price is apportioned between these two amounts is arbitrary. Capacity payments in the WEM are based on the fixed costs of a liquid fuelled peaking facility. This does not bear any relevance to the fixed and variable costs of a base load facility. The capacity market simply creates a demand for an abstract financial instrument (capacity credits) that is met by the award of a right to generate capacity credits by the IMO to a generator.

While the value of a generator's output is affected by whether it is granted this right, the *quantum of this value* to any generator which sells a product that is composed of more than capacity alone[7] is arbitrary and is simply required to complete a settlement loop. The generator effectively has two separate commitments for contracted availability.

- The first is to its off take counterparty for the delivery of the (real) output of the plant.

- The second is to the IMO to meet the requirement for the award of an (abstract) capacity credit.

A new entrant generator is incentivised to meet its project delivery dates by its contractual off-take obligations. *The capacity refund mechanism, by refunding capacity credits at higher rate than being granted them, simply becomes an arbitrary financial penalty*[8] – or a cost additional to the cost of meeting the contracted commitments. If a new generator expects that it might incur additional costs for not delivering on time (where as a new entrant generator it is at its most vulnerable to construction risk and force majeure, which are largely non-controllable risks), it will 'manage this risk' by pricing the cost of these refunds into the project development as an additional contingency. This is a commercial reality of project development, where financiers protect their investments as a priority. The cost of financing the additional risk premium is a cost that is then borne by the market through higher wholesale electricity prices – whether the generator incurs the capacity penalties or not. While the generator, though poorly equipped to manage this risk, is probably still the best placed to do so, Griffin contends that the risk itself should not be

[7] For a pure peaking plant (or one that provides capacity to meet only the marginal MWh of demand in the system), the LRMC of production is equivalent to the fixed capital cost. In this case, the price paid for capacity is important.

[8] The IMO describes capacity refund repayments as a 'refund' only and is careful not to use the term 'penalty'. If the repayments to the IMO were made at the same rate at which the capacity payments were made (or at a reduced rate), then the term refund (or partial refund) would be sensible. As the repayments are made at a rate that is higher than payments; and, importantly, for a generator that has contracted off take obligations to transfer capacity rights, as the difference between payments an repayments is unable to be recouped once the plant is available again, then the capacity repayments made above the level of capacity payments received can only logically be viewed as a penalty.

there in the first place, as there is little additional return to the cost imposed in managing it.

The argument that: if the generator does not price in this cost, then others in the market (i.e. retailers) will price it in, is flawed. This is only applicable if the late delivery of a generator actually leads to higher market costs. Higher costs may be incurred through calling for supplementary reserve capacity (SRC) and through replacing the expected generation with higher cost generation in the market. Griffin does not believe there is sufficient evidence to suggest that forcing a generator to price in the potential refund penalty cost of each project development (regardless of whether it incurs penalties) – and pass that cost on through higher wholesale pricing, is more efficient (cost effective) than incurring costs relating to SRC on an infrequent basis[9]. The second potential market cost impost; that of higher priced electricity for the marginal unit not produced by the generator, will primarily be ***borne by the generator in a bilateral market*** (through its supply obligations) and is actually their main driver for ensuring timely delivery.

1.4 The Proposal and the Wholesale Market Objectives

Griffin submits that its proposed rule change proposal better achieves the Market Objectives (a); (c) and (d); and has a neutral affect on objectives (b) and (e).

(a) to promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West interconnected system;

(c) to avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions;

(d) to minimise the long-term cost of electricity supplied to customers from the South West interconnected system;

It is Griffin's view that to promote a reliable supply of electricity, appropriate incentives must be applied that encourages generators to be available at times of peak demand. To ensure that these incentives are also economically efficient, a correct balance must be achieved between financial incentive and an inefficient cost. Costs that do not improve reliability and are ultimately passed through to consumers are clearly economically inefficient. The proposed rule change seeks to address the application of inefficient costs, especially to new entrant generators which are more exposed to these costs and less likely to be able to respond to them with improvements in reliability.

Further, Griffin contends that inefficient financial penalties for new entrant generators that have not yet commissioned plant may potentially lead to work practices that result in less stringent safety and reliability standards. The safe and reliable production of

[9] The fact that SRC is potentially uncapped would appear a flaw in an otherwise price regulated market

electricity in the SWIS is a very serious concern and must certainly extend to the construction of new entrant generation facilities.

Griffin submits that the rule, as it currently stands, discriminates against the differing risk profiles of new entrant generators over incumbent generators as well as (and especially) against new entrant generators with high fixed capital costs and long lead time projects. The proposed rule change offsets some of these discriminatory effects.

Griffin defines inefficient costs, as outlined in point (a), as being those imposts on Market Participants that do not return a net value to the market. New entrant base load and mid merit generators that rely on; and are incentivised to be available by; their energy sales obligations are poorly incentivised (if at all) by excessive capacity refunds. These costs (whether actual or contingent) will ultimately be passed on to consumers.

1.5 Amending Rules

To meet Griffin's Rule Change request, the IMO has proposed that the Refund Table and definitions be amended as shown in Figure 1-4.

1.6 Summary of MMA's Assessment

Based on a review of the submissions and a multi-criteria analysis of the Rule Change proposal against the Market Objectives, MMA does not support the Rule Change 35 because it makes no significant improvement in meeting the Market Objectives and has scope for a slight detrimental effect on supply reliability.

MMA considers that seasonal caps might be useful to spread the incentive to manage performance over the year but it has not been established that seasonal caps would materially reduce the financial risk of delayed commissioning in a way that balances the costs of recovery from project delays, the costs of SRC and the costs imposed on customers from inadequate reliability. Indeed there is the risk of an unintended consequence of reducing the incentives for return of peaking plant from outages later in the seasons when the cap on Capacity Payment Refunds would be effective. This would reduce reliability and increase the risk of the need for Supplementary Reserve Capacity.

In view of the concern about successive changes to the processes around the Refund Table and the insufficient evidence of the efficiency or otherwise of the current arrangements, MMA considers that there is no immediate need to reimpose seasonal caps without reference to a reliability assessment and consideration of the impact of lead time on the refund processes. It is likely that the current refund profile that caps out between 5.5 and 10.3 months depending on the start time is not optimal but nor is it significantly inefficient to warrant the changes proposed by Griffin Energy.

Figure 1-4 Proposed amended Refund Table

Dates	1 April to 1 October	1 October to 1 December	1 December to 1 February	1 February to 1 April
Business Days Off- Peak Trading Interval Rate ($ per MW shortfall per Trading Interval)	0.25 x Y	0.25 x Y	0.5 x Y	0.75 x Y
Business Days Peak Trading Interval Rate ($ per MW shortfall per Trading Interval)	1.5 x Y	1.5 x Y	4 x Y	6 x Y
Non-Business Days Off-Peak Trading Interval Rate ($ per MW shortfall per Trading Interval)	0.25 x Y	0.25 x Y	0.5 x Y	0.75 x Y
Non-Business Days Peak Trading Interval Rate ($ per MW shortfall per Trading Interval)	0.75 x Y	0.75 x Y	1.5 x Y	2 x Y
Maximum Seasonal Cap ($ per maximum possible Trading Interval MW shortfall per season multiplied by the expected annual Capacity Credit payments)	0.30 x A	0.10 x A	0.25 x A	0.35 x A
Maximum Participant Refund	The total value of the Capacity Credit payments paid or to be paid under these Market Rules to the relevant Market Participant for the 12 Trading Months commencing at the start of the Trading Day of the previous 1 October assuming the IMO acquires all of the Capacity Credits held by the Market Participant and the cost of each Capacity Credit so acquired is determined in accordance with clause 4.28.2(b), (c) and (d) (as applicable).			

Where:

For an Intermittent Facility that has been commissioned: Y equals 0; and A equals 0

For all other facilities, including Intermittent Facilities that have not been commissioned: Y equals the greater of the Reserve Capacity Price and 85% of the Maximum Reserve Capacity Price for the relevant Reserve Capacity Auction, expressed as a $ per MW per Trading Interval figure. This is determined by dividing the Monthly Reserve Capacity Price by the number of Trading Intervals in the relevant month; and A equals the total value of the Capacity Credit payments associated with the relevant Facility paid or to be paid under these Market Rules to the relevant Market Participant for the 12 Trading Months commencing at the start of the Trading Day of the most recent 1 October, assuming the IMO acquires all of the Capacity Credits associated with that Facility and the cost of each Capacity Credit so acquired is determined in accordance with clause 4.28.2(b), (c) and (d) (as applicable).

2 REVIEW OF SUBMISSIONS

Four submissions have been received on the Rule Change as summarised in Table 2-1 together with a summary of MMA's reviews based on the analysis in the previous Chapter. The Working Group analysis is based on the Minutes of the 23rd January 2009 meeting.

Only Griffin supports the Rule Change as having material benefits to the market as a whole. The assumed path for these benefits to flow to customers is reduced risk exposure to new base load generators which results in lower wholesale prices to customers, assuming that the reduced penalties have no effect on the availability of new or existing plant and the cost of acquiring Supplementary Reserve Capacity. These assumptions are discussed in this chapter and the discussion of the Market Objectives in Chapter 3.

2.1 Basis for change

A position has been put that too many rule changes related to the Refund Table has created the impression of too much regulatory risk in the WEM. This is an argument for maintaining the status quo. It is preferable to conduct a proper assessment and take a position that will stand the test of time, rather than conduct a series of changes and improvements in response to issues as they arise. If frequent small changes occur, seemingly to correct for anomalies not previously identified with recent changes, then the Rule Change process will lack credibility and investors may shy away from the WEM.

Since Rule Change 35 reverts to a principle previously abandoned, that of imposing seasonal caps on Capacity Refunds, there would need to be a substantial justification that the Market Objectives are to be met more effectively. Most of the respondents to the Notice of Rule Change are not persuaded that the benefit for the Market is significant enough or even positive to be worth proceeding with another change to the Refund Table.

2.2 Basis for reducing the Capacity Payment Refunds

What's missing in Griffin's request is a thorough economic analysis of the basis for the parameters in the Refund Table in relation to the reliability of supply and the cost of managing the risk of project delays. In section 2.4 we have attempted to make an assessment of the relative value of reimposing seasonal caps. It is estimated that the full Capacity Payment Refund for delay of a large 200 MW unit is likely to be less in magnitude than the unreliability costs faced by customers if the current 0.002% reliability

Table 2-1 Analysis of submissions to Rule Change 35 Proposal

Market Issue	Griffin	Alinta	Landfill Gas & Power	Synergy	Working Group	MMA View
Overall view of the Rule Change	Has instigated and supports the Rule Change to reduce the working capital and insurance cost of base load projects arising from the risk of construction delays to thereby reduce overall costs in the market.	Does not support the Rule Change. New entrants have the opportunity to receive capacity payments from 1 August to manage the risk of delay. The Rule Change is unnecessarily broad in its application.	Recognises Griffin's arguments in favour of the Rule Change proposal but does not support the Change. LGP perceives that the impact of the proposed changes are relatively minor for the market as a whole, subjective, and context-dependent.	Does not support the Rule Change as its impact would be minor and potentially negative with respect to the Market Objectives. Synergy would support it if lower generation costs could be proven.	Most of the WG members do not support the change. There is already sufficient incentive for minimising delays to service of new plant.	The Rule Change is not supported by economic analysis to justify the view that a material improvement in market efficiency and electricity supply costs could be demonstrated. Any reduction in Capacity Payment Refunds by applying seasonal caps are likely to be negated by the costs of Supplementary Reserve Capacity under Rule Change 34.

Market Issue	Griffin	Alinta	Landfill Gas & Power	Synergy	Working Group	MMA View
Relative competition of technology types	That the current regime presents additional risks to capital intensive base load equipment relative to open cycle gas turbine technologies and therefore biases the market in favour of peaking plant, which would not be efficient. The additional risks occur because the greater complexity increases the probability that such plants will be delayed in commissioning.	It would be inequitable to provide the same Capacity Payments whilst accepting greater risks of performance for new entrants. Imposing seasonal caps will only benefit new entrants.	Relatively minor impact.	The Rule Change does not promote lower generation costs for any technology and size.	There are different incentives for new and existing generators. Rule Change does not reduce barriers to entry. No significant difference in impacts for different capacity sizes.	The Rule Change would reduce the financial risk to base load plants but would not change the already strong incentive to deliver capacity on time. The current Rules apply equally to all technologies and have the potential to under-state customer impacts if SRC cannot be procured at less than the Maximum Reserve Capacity Cost.

Market Issue	Griffin	Alinta	Landfill Gas & Power	Synergy	Working Group	MMA View
System Reliability	Base load generators already have a strong incentive to be available as planned due to their heavy reliance on production to meet energy intensive bilateral contracts. They do not need punitive measures to provide additional incentive. Punitive measures are counter-productive because if delays occur, they reduce the financial capacity of the generators to respond to the contingencies.	It is appropriate to provide a strong incentive for new entrants to deliver capacity by 1 December to meet the summer peak needs.	Relatively minor impact.	No impact because base load facilities already have sufficient incentive for timely commissioning.	No material effect on reliability of the need to call for SRC. Some outages might be extended. Winter reliability increased and summer reliability may decrease.	Griffin's argument that base load generators already have a strong incentive shows that reimposing seasonal caps is unlikely to change that incentive and therefore have no impact on supply reliability.

Market Issue	Griffin	Alinta	Landfill Gas & Power	Synergy	Working Group	MMA View
Regulatory Risk	If a previous rule change results in treating a single (or group of) Market Participants "unduly harshly" – whether intended or not – in contravention of a direction from the Office of Energy (and economic efficiency principles) then not addressing this through the market rule change process might lead to a greater perception of regulatory risk.	No comment	No comment	Making a further rule change shortly after completing an extensive consultation process on refund allocation, which gained broad market participant approval, potentially reduces confidence external observers would have of the rule change process. Synergy is concerned particularly that potential facility investors would not perceive this rule change as an improvement, but as a sign of market governance instability.		A position has been put that too many rule changes related to the Refund Table has created the impression of too much regulatory risk. Whilst this is an appealing argument for status quo, it is more important to conduct a proper assessment and take a position that will stand the test of time, rather than responding to every issue or qualitative argument which is raised. Refer argument in section 2.1.

Market Issue	Griffin	Alinta	Landfill Gas & Power	Synergy	Working Group	MMA View
Market objective (a) – safe efficient and reliable supply of electricity	Decreases regulatory risk and cost with no detriment to safe, reliable and efficient supply of electricity	There is no evidence of improvement to efficiency, safety and reliability of supply. There is no additional incentive to reduce the probability of unplanned outages.	Market Objectives are not better achieved.	Marginal or potentially negative impact.	No significant effect apart from some risk of slightly higher reliability in winter and lower in summer.	No material impact as there is no significant to change in incentive to commission new capacity on time.
Market objective (b) - competition	Marginal improvement to competition by encouraging the most appropriate supply mix	It is unclear that the Rule Change would materially alter the project's overall risk profile.	Market Objectives are not better achieved.	Marginal or potentially negative impact.	No reduction in the barriers to entry.	No significant impact on competition as it would not change the commercial drivers to enter the market. A change in the new entrant risk profile would affect all new entrants. It may slightly bias entry towards base load but not change overall competition.

Market Issue	Griffin	Alinta	Landfill Gas & Power	Synergy	Working Group	MMA View
Market objective (c) – no technology discrimination	Reduces the discrimination against large base load new entrants.	It is possible that the Rule Change would be of greater benefit to new peaking plant facilities compared with new base load facilities, given the greater reliance of peaking plant on capacity payments.	Market Objectives are not better achieved.	Marginal or potentially negative impact.	The Rule Change is unlikely to change market participant behaviour	It would slightly favour base load capacity by reducing some financial risk. However the penalties are formulated with a view to customers' overall costs and either way the same rules would apply to all technologies so there is no bias in that respect.
Market objective (d) – minimise cost	Wholesale cost of electricity will be reduced.	It is unlikely to reduce costs because reduced refunds may not cover the costs that are already covered by the Market Rules.	Market Objectives are not better achieved.	Marginal or potentially negative impact.	It is unclear how the Rule Change would affect overall market costs. There would be effects for individual generators.	Overall wholesale costs would be slightly increased if the seasonal caps result in delayed return to service and less incentive to reduce outages and delayed commissioning results in additional SRC costs.

Market Issue	Griffin	Alinta	Landfill Gas & Power	Synergy	Working Group	MMA View
Market objective (e) – demand side participation					The Rule Change has not effect on demand side participation.	

standard is deemed to be economically efficient[1].

It is best to have the capacity payments match the impact on customers and the cost of surplus capacity (as delivered by gas turbines) and then take that revenue away in accordance with the customer impact and the short-term cost of Supplementary Reserve Capacity. That should provide the correct signals to all new entrants irrespective of their technology.

2.3 Technology bias

If the costs to customers of delayed service of new plant without notice are high then the penalty should match the lowest of:

- The cost of acquiring replacement capacity from supply or demand side - so that replacement capacity may be acquired if this is the most economic response
- The customer impact - so that customers can be compensated appropriately if replacement capacity is not available
- The cost of advancing efforts to bring the plant in on time – so that the generator has sufficient incentive to recover if that is feasible.

The list would be expected to be in order of least cost to highest cost or highest feasibility to least feasibility. If the penalty payment matches the lowest in cost of these impacts in any situation, then the right response will be incentivised as follows.

In the first instance the potential penalty would be addressed by the generator seeking to recover the lost construction time and the capacity deficit. This may not be financially or technically infeasible. If so, the potential capacity payment refund stands.

In response to this situation the IMO will seek replacement capacity if required to maintain system reliability. Assuming that is feasible and that the cost is less than the customer impact, as would be expected for a significant capacity deficit, then that should proceed. Indeed the Market Rules imply that this is always the case as there is no reserve price on Supplementary Reserve Capacity, in the expectation that there will always be sufficient demand side response to meet the reliability requirement economically. If the cost of replacement capacity is greater than the refunded Capacity Payments, then Rule Change 34 seeks to obtain additional funding from the generators that have caused the capacity deficit. That the offending generators should receive a loss of income that is less than the cost of advancing works means that they receive the proper economic incentive and compensate the customers who are in no position to manage construction duration

[1] A reliability standard is economically efficient when it minimises the total cost of supply of electricity and electricity supply disruptions, that is when the sum of reserve capacity costs and electricity supply disruptions is minimised on an expected value basis or some suitable probabilistic measure. From the standard, the sensitivity of unserved energy to reserve capacity, the cost of reserve capacity, it is mathematically feasible to estimate the marginal value of unserved energy.

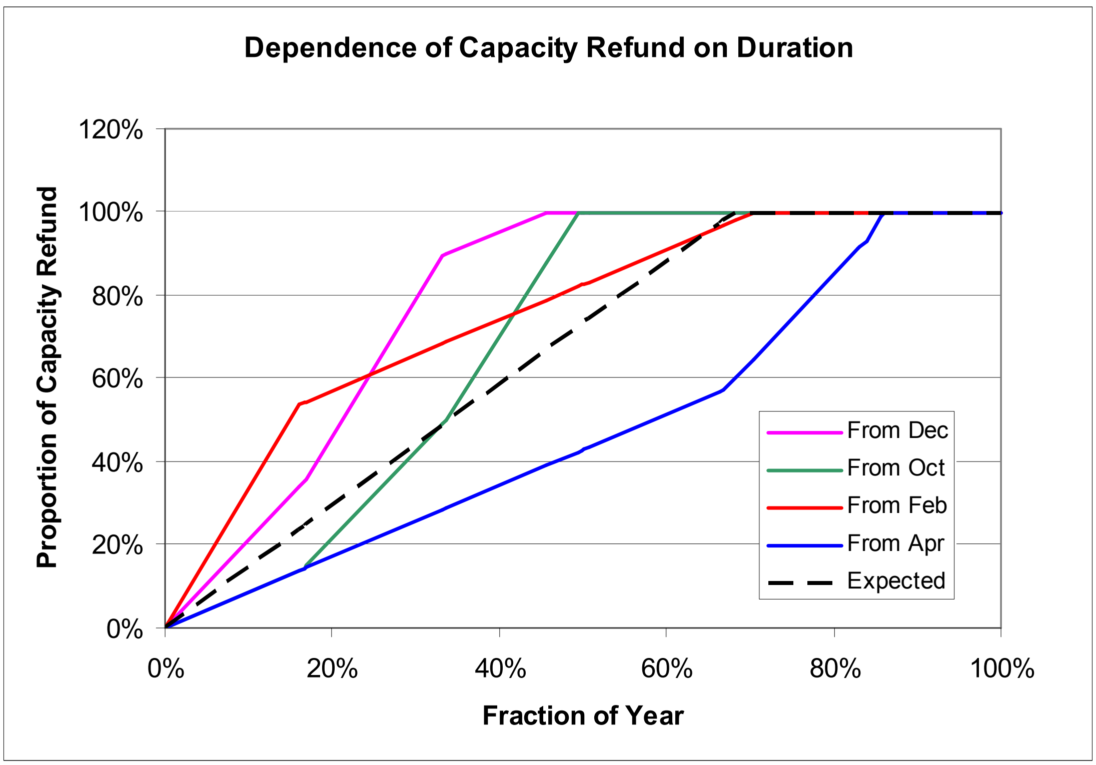
risk. This produces an efficient outcome through the procurement of replacement capacity[2].

2.4 Value of seasonal caps

Whether or not the imposition of seasonal caps produces a more efficient outcome has not been demonstrated by the Griffin submission by the provision of evidence of an economic model. There is a qualitative argument in favour of seasonal caps:

- Seasonal caps reduce financial exposure for capacity providers in situations where there is no further penalty in the short-term to extending the outage. This is illustrated by the current arrangements shown in Figure 1-1 where there is no further change in the financial penalty after 5.5 months from 1 October until the beginning of the next contract year. A fuller analysis which shows varying starting periods for an extended outage is shown in Figure 2-1. The green line in Figure 2-1 corresponds to the orange profile presented by Griffin in Figure 1-1.

Figure 2-1 Profile of Capacity payment Refund by Duration of Outage



- This capping of financial exposure reduces the risk that Capacity Payment Refunds will exceed the appropriate incentive to the capacity provider to recover from the loss of capacity. If the incentive to respond is already strong due to the loss of energy

[2] The Market Rules use the term "Supplementary Reserve Capacity" (SRC). We have used the term "replacement capacity" to avoid any necessary linkage to the concept of SRC as defined in the Rules. It is possible (although unlikely) that the capacity could be replaced by the market iteself without resorting to the SRC procurement process.

sales, then the uncapped refund profile is no better in providing a suitable incentive than the capped profile.

However, it has not been demonstrated whether the current profile or the alternative proposed by Griffin reflects the true impact on system reliability and customer impact. In reality, there would be no timeless definitive answer because the value would depend on a host of market variables that are uncertain and change over time[3]. Thus for the purposes of the Market Rules in the absence of strong support for total reform of the Refund Table, it is a matter of opinion as to whether the reimposition of seasonal caps is generally acceptable to Market Participants.

Alinta argues that the reimposition of seasonal caps would mostly favour new entrants because they have the greater risk of extended outages associated with plant commissioning. However they would still receive the same Capacity Payments if planned service is achieved and they have the opportunity to earn Capacity Credits from 1 August at the full rate even though the extra capacity would have less marginal market value. Alinta considers that the Capacity Payments to new entrants should be differentiated if a greater portion of the risk of late commissioning is to be borne by customers.

There are reasons why the Capacity Refunds should not be limited to the Capacity Credit Payments when there are substantial capacity shortfalls that occur without sufficient time to respond in an economic manner:

- The cost of capacity planned well in advance is represented by the fixed cost of liquid fuelled peaking plant. Thus with adequate notice, 100% refund of the Capacity Payment is economic.
- Without sufficient notice, there are additional costs either due to limited options, such as reliance on demand side response which is purchased under limited competition and lead time duress, or excessive customer supply interruptions if no replacement capacity can be procured. Thus there is an economic basis for more than refund of the Capacity Payments to be appropriate when the notice of extended outage is short.
- Thus Griffin's argument concerning inefficient penalties is incomplete without reference to the notice applied to the extended outage or delayed commissioning. Since the Market Rules provide for the procurement of Supplementary Reserve Capacity between 6 months and 12 weeks prior to its need, there is the implication that notice greater than 6 months can be accommodated by the normal process for acquiring reserve capacity and if shorter than 12 weeks then an auction is not feasible and direct negotiations are required to meet the lead time requirement. Rule Change 34 will provide the IMO with the ability to pass on more than the full annual Capacity Payment if needed to fund SRC, as might be expected under such short lead times.

In conclusion, MMA considers that seasonal caps might be useful to spread the incentive to manage performance over the year but it has not been established that seasonal caps

[3] Synergy uses the term "context dependent" to refer to this matter.

would materially reduce the financial risk of delayed commissioning in a way that balances the costs of recovery from project delays, the costs of SRC and the costs imposed on customers from inadequate reliability.

In view of the concern about successive changes to the processes around the Refund Table and the insufficient evidence of the efficiency or otherwise of the current arrangements, MMA considers that there is no immediate need to reimpose seasonal caps without reference to a reliability assessment and consideration of the impact of lead time on the refund processes. It is likely that the current refund profile that caps out between 5.5 and 10.3 months depending on the start time might not be perfect but it probably is not grossly inefficient either.

2.5 Incentive for base load plant

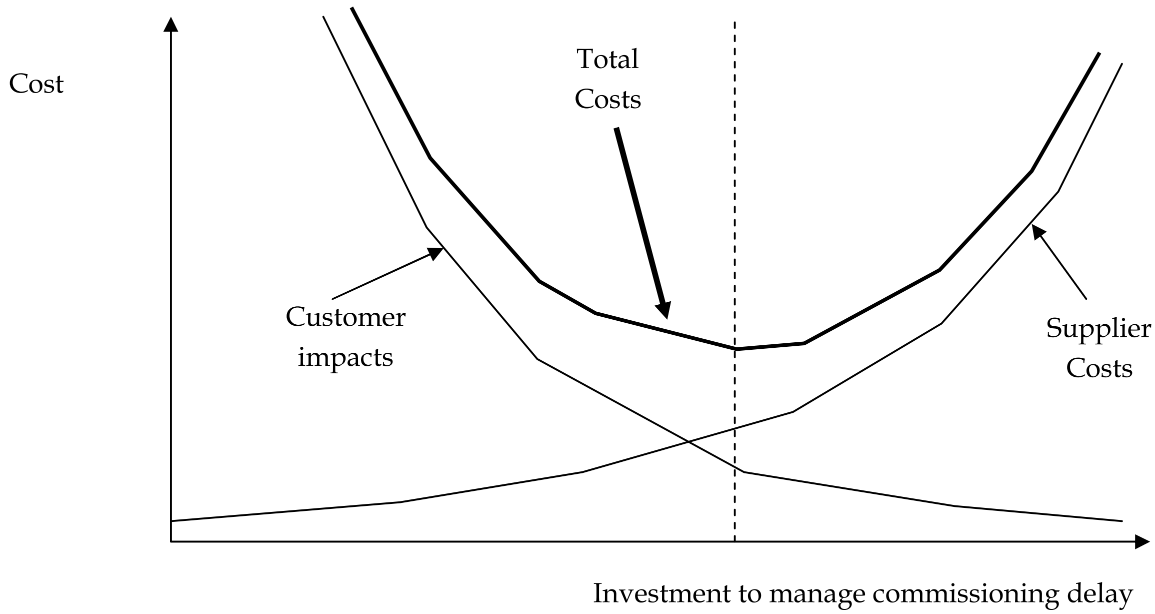
The argument that base load plant already has greater incentives than peaking plant to meet its bilateral obligations means that the penalty regime should not be that important for a base load new entrant until it knows that it will not meet its capacity obligation. The current penalty in aggregate, and considering the related Rule Changes, is commensurate in magnitude with the costs for the wider market having regard to alternative capacity sources and the impact on customers of lower reliability. Reducing the rate of Capacity Payment Refund would certainly be beneficial to the base load provider in that event but it would do nothing to benefit customers under the contingency of delayed new entry.

A priori, before a generator knew that they have a real risk of delayed commissioning, will certainly need to make working capital provision or take insurance for the possibility of the loss of the capacity payment. If the risks are substantial, then making that provision is economic and the higher costs passed through to customers would truly reflect the exposure to that risk. When a delay occurs, the funds would be available to compensate customers for their higher costs of unserved energy and replacement capacity. Thus in the generator paying a premium for insurance against delayed new entry and passing that cost on to customers in higher energy prices and in some years the customers receiving the compensating Capacity Payment Refund to mitigate the cost of low reliability and paying for SRC is not in itself a measure of inefficiency.

Assuming that additional supplier costs are passed through to customers in higher charges, there is an optimum point where the total cost of suppliers' insurance charges and customer costs from poor reliability are minimised as illustrated conceptually in Figure 2-2. This optimum place cannot be readily assessed by the IMO because the trade-offs between penalties and costs are not known. Specifically, there is no readily available economic model which provides this information.

Typically such optimisations have quite flat regions where the cost is minimised and there is scope for defining variables to be out by up to 50% to 100% without having more that about 5% to 10% impact on the total costs.

Figure 2-2 Illustration of efficiency in managing risk of commissioning delay



It is difficult to quantify this risk analysis having regard to the complexities of insurance costs, working capital costs, differences in technology, consequences for reliability and customer impact costs to be more certain as to whether the reimposition of seasonal caps would make much difference overall. It is a complex and speculative analysis even if some date were available.

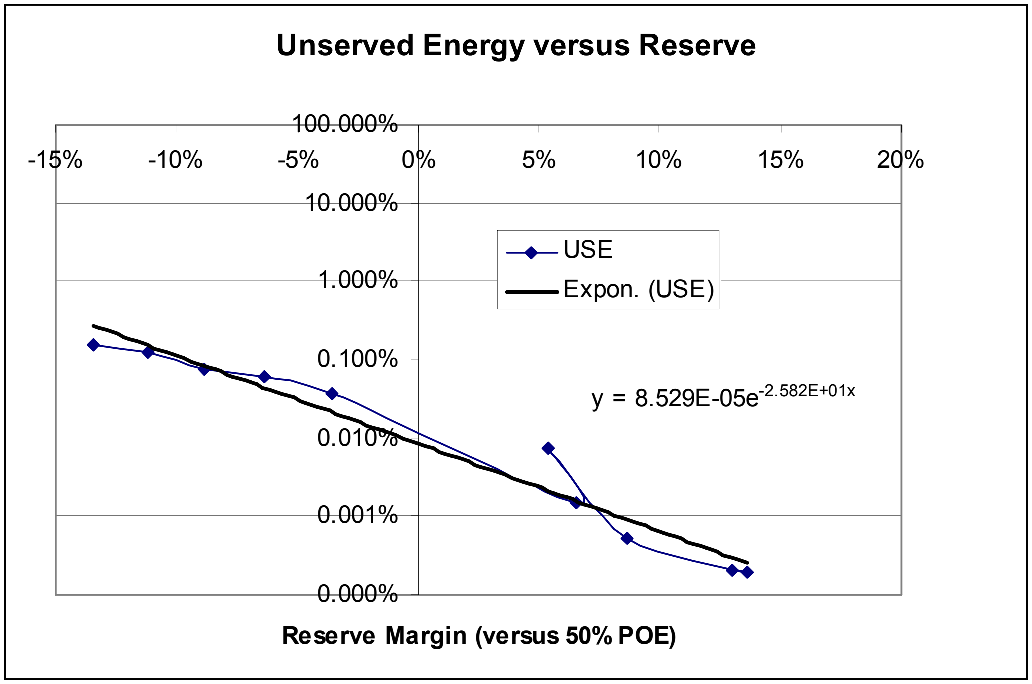
MMA has attempted to put some estimates on economic value based on some previous SWIS reliability modelling. This analysis is not highly refined and is partly based on some parameters derived from NEM experience[4]. The current 0.002% reliability standard values marginal unserved energy at about $44/kWh based on the relationship between reserve margin and unserved energy as shown in Figure 2-3. Each diamond corresponds to a financial year with no new capacity. The unserved energy doubles for a 2.7% reduction in reserve margin relative to 50% POE peak demand.

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[5]. 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.

[4] In particular the approximate weighting to 90%, 50% and 10% POE peak demand conditions in representing the impact of the continuous distribution of peak demand and unserved energy uncertainty of 30%, 40% and 30% respectively.

[5] Based on $25/MWh increase in energy cost and 85% capacity factor. This assumes a STEM prcie of $45/MWh and a short-run marginal cost for the coal plant of $20/MWh.

Figure 2-3 Unserved energy versus reserve margin over 50% POE peak demand



This is not a definitive assessment as some methods and assumptions need to be properly tested and modelled, but it does indicate that:

- Delay of a base load new entrant can create customer costs exceeding the refund of capacity payments by about 50% if replacement capacity cannot be procured. This closely approximates the sum of the terms in the Refund Table which come to 146.5% as shown in Table 2-2. This demonstrates consistency with the analysis behind the current Refund Table.
- The Generator would face a similar magnitude of costs in purchasing from the STEM to replace the lost production if it had a bilateral contract;
- If replacement capacity costs substantially more per MW than the Maximum Reserve Capacity Price then it is unlikely that the refund of the Capacity Payment would be sufficient compensation.

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.

Table 2-2 Capacity Payment at Risk

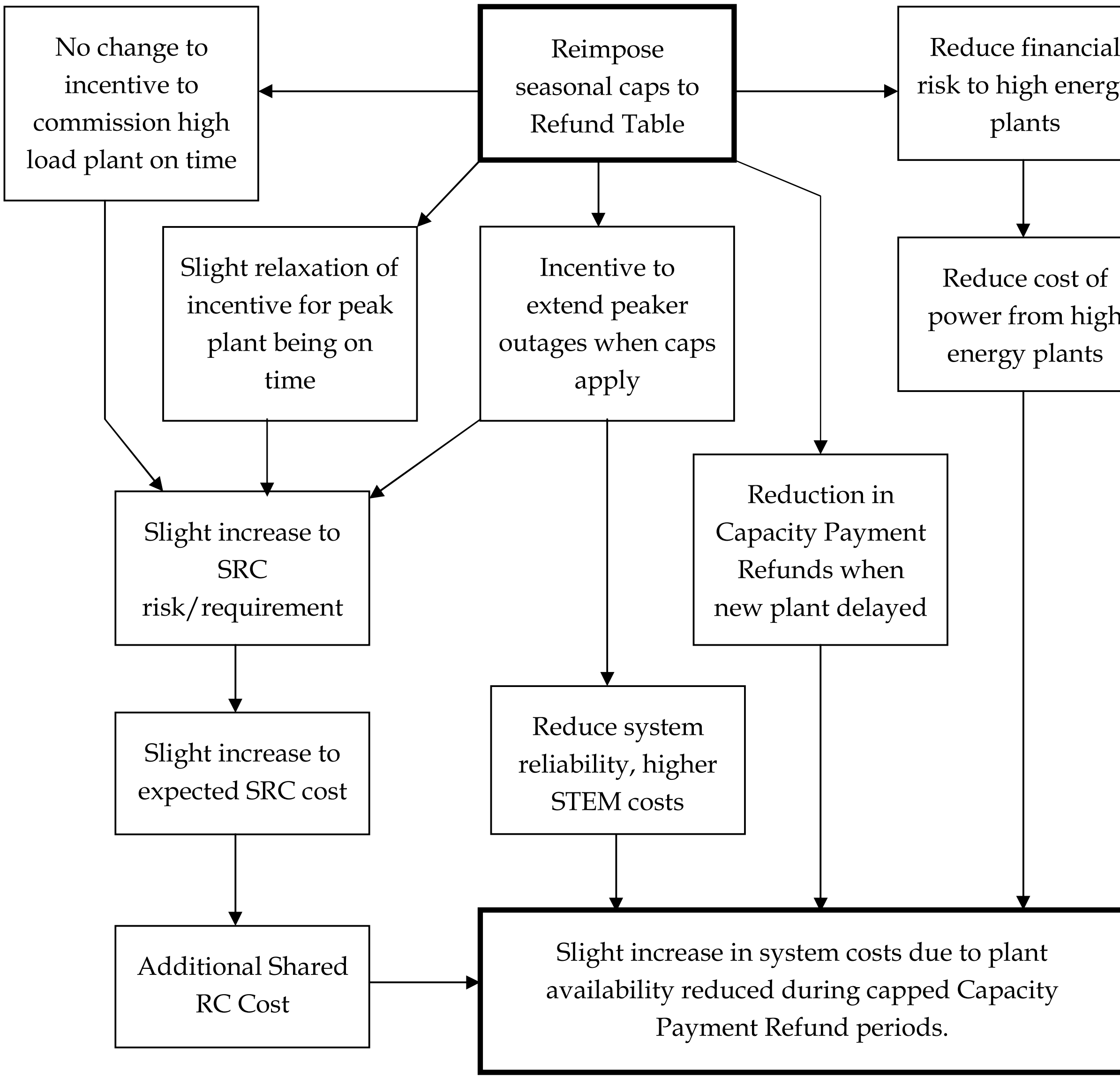
From	1-Apr	1-Oct	1-Dec	1-Feb	
To	1-Oct	1-Dec	1-Feb	1-Apr	
	Ratio of Monthly Capacity Payment				**Average**
Bus Off-Peak	0.25	0.25	0.5	0.75	0.375
Bus Peak	1.5	1.5	4	6	2.667
Off-peak	0.25	0.25	0.5	0.75	0.375
Non-Bus Peak	0.75	0.75	1.5	2	1.083
	Proportion of the Capacity Payment Available				**Total**
Bus Off-Peak	15.0%	5.0%	5.0%	5.2%	30.3%
Bus Peak	21.0%	7.0%	7.1%	7.3%	42.4%
Off-peak	5.8%	1.9%	1.9%	1.8%	11.4%
Non-Bus Peak	8.1%	2.7%	2.7%	2.5%	16.0%
					100.0%
	Proportion of the Capacity Payment at Risk				**Total**
Bus Off-Peak	3.8%	1.3%	2.5%	3.9%	11.4%
Bus Peak	31.6%	10.5%	28.2%	43.5%	113.8%
Off-peak	1.5%	0.5%	1.0%	1.3%	4.2%
Non-Bus Peak	6.1%	2.0%	4.0%	4.9%	17.1%
					146.5%

2.6 MMA observations

MMA's analysis of how the Rule Change proposal influences system costs is summarised graphically in Figure 2-4. The assessment in the first order is based on the following expectations:

- There is already sufficient incentive for high energy plants to be commissioned on time and changes to the Refund Table under the proposed Rule Change 35 will have no effect on this incentive.
- There is already sufficient incentive for incumbent high energy plants with low short-run marginal costs to return to service as quickly as possible due to their energy value relative to system marginal costs based on gas and distillate fired open cycle gas turbines. The Rule Change would not be expected to alter plant availability for high energy plant during capped or uncapped periods.
- This means that there would be no change to the need for Supplementary Reserve Capacity (SRC) due to responses from high energy new entrants or incumbents.
- The less stringent Refund Table may result in the delay to service of liquid fuelled peaking plant as there is little other revenue at stake for a delay. This may slightly increase the need for SRC. To the extent that such outage extensions are not foreseeable and temporary they would be unlikely to encourage the IMO to acquire SRC on every occasion of an outage.

Figure 2-4 Analysis of Impacts of Rule Change 35



Note: The above analysis neglects changes arising from secondary effects on market behaviour and regulatory risk arising from the Rule Change.

- Thus customers on an expected basis face a small risk of slightly increased SRC exposure due to possible delays to new peaking plant or extension of outages by incumbents.
- The reduced Capacity Refunds to new entrant generators arising from the seasonal caps result in higher costs to customers from the reduction in Capacity Payment Refunds which may be offset by reduced costs for wholesale power from generators. Assuming that all other risks are unchanged, including regulatory risk arising from the Rule Change these two cost components should cancel each other out.

- There would also be some additional STEM costs arising from lower reliability from existing plants that would have occasional windows when the Capacity Refunds are temporarily capped for the remainder of the season and the incentive to return plant to service would be diminished, particularly for peaking plant.

Most of these effects would be at the margin and hardly measurable and in the real world the counter factual conditions would not be observable. The perception of Synergy Energy that the Rule Change could be slightly negative may arise from the reduced incentive on peak plant incumbents to return plant as soon as practicable at all times.

MMA considers that there is no case to provide different incentives to maintain planned capacity for different technologies on account of their different risk profiles because from a customer viewpoint, only the capacity matters as long as the customer is bilaterally contracted and thus protected from the STEM. Therefore it doesn't matter what kind of plant is unavailable, the customer effect is similar. That some high capital cost technologies with long construction times have greater risks is offset by their lower short-run marginal costs and their higher income earning potential. As long as the pricing structure of the Capacity Payment refund regime is matched to the cost of peaking plant, the cost of supply interruptions to customers and the cost of replacement capacity from the demand side, it would be expected to provide economic incentives to all technologies and plant sizes. If base load plants developers perceive this risk profile as delaying commitment to new entry until the project value is increased accordingly, then that is an efficient response having regard to the risk.

One matter that has not been addressed in the submissions is that delay of large base load plants has the risk of higher per MW SRC costs because a greater capacity volume is to be replaced and the costs to customers of the lower reliability is greater if the market would otherwise have been in supply/demand balance. This is where size does matter and there is no good reason to relax the potential penalties for large base load plants because their timely delivery is even more important if the market is relying on their capacity, especially when it coincides with retirement of old plant.

There is no doubt scope for reliability analysis to refine the parameters in the Refund Table of 4.26.1. This is not recommended in the absence of a thorough review of reliability and capacity management in the WEM. The preliminary analysis in section 2.4 shows that the aggregate penalty level is at an appropriate magnitude for 200 MW units.

3 ANALYSIS OF MARKET OBJECTIVES

3.1 Criteria and General Approach

The issues that are relevant in the consideration of a rule change are prescribed by the Market Rules. In particular, the Market Rules specify a number of objectives that must be satisfied as part of a rule change determination process; specifically:

> *2.4.2. The IMO must not make Amending Rules unless it is satisfied that the Market Rules, as proposed to be amended or replaced, are consistent with the Wholesale Market Objectives.*

The Wholesale Market Objectives are set out in Section of 122(2) of the Electricity Industry Act and also repeated in clause 1.2.1 of the Market Rules:

> *1.2.1. The objectives of the market are:*
> *a) to promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West interconnected system;*
> *b) to encourage competition among generators and retailers in the South West interconnected system, including by facilitating efficient entry of new competitors;*
> *c) to avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions;*
> *d) to minimise the long-term cost of electricity supplied to customers from the South West interconnected system; and*
> *e) to encourage the taking of measures to manage the amount of electricity used and when it is used.*

The Market Rules provide the IMO with additional guidance to assist in a rule change determination:

> *2.4.3. In deciding whether or not to make Amending Rules, the IMO must have regard to the following:*
> *a) any applicable policy direction given to the IMO under clause 2.5.2;*
> *b) the practicality and cost of implementing the Rule Change Proposal;*
> *c) the views expressed in any submissions on the Rule Change Proposal;*
> *d) the views expressed by the Market Advisory Committee where the Market Advisory Committee met to consider the Rule Change Proposal; and*
> *e) any technical studies that the IMO considers are necessary to assist in assessing the Rule Change Proposal.*

The reality of most organised energy markets is that factors such as industry structure, the form and operation of physical, institutional and financial infrastructure, and other investment and behavioural factors combine to produce an evolving market that does not guarantee the absolute and complete achievement of market objectives such as those prescribed by the Market Rules. Indeed, the circumstances of a rule change proposal may often imply the need to compromise the attainment of some objectives, or to seek an improvement but not complete attainment of particular objectives. This is often made the case when the system cost of a change may require excessive resource requirements, or when legacy contracts, agreements or transactions make the proposed change costly or problematic.

For this reason what is important in a rule change determination, is a relative assessment of a change proposal, comparing expected change outcomes with the status quo, and using a method that can balance varying degrees of improvement or otherwise in the attainment of multiple objectives.

The method that is used in this rule change analysis is therefore Multi-Criteria Analysis (MCA). MCA provides an approach and framework that can quantify the assessment outcomes of multiple criteria that may be qualitative and multi-faceted in specification.

3.2 Multi-criteria Framework

The MCA framework for this rule change assessment is defined as follows:

- Decision criteria: These are based on the Market Objectives, and any further criteria that may be an outcome of the guidance provided by section 2.4.3 of the Market Rules. Two classes of criteria are considered:
  - Core criteria (based on Market Objectives) and
  - Non-core criteria (identified via section 2.4.3 of the Market Rules);
- Assessment indicators: These are defined for each decision criterion; they essentially provide a test or indicator that can be used to measure the relative attainment of the criterion based on an assessment of the proposed change;
- Indicator valuation: This provides for a quantitative measure of the assessment indicator, assessed either individually, or collectively for a class of indicators that together assess the achievement of a criterion. This analysis uses the following valuation scheme to provide a collective assessment of each class of indicator:
  - The indicators indicate that the achievement of the criterion is strongly improved (Quantitative score = 3)
  - The indicators indicate that the achievement of the criterion is moderately improved (Quantitative score = 2)
  - The indicators indicate that the achievement of the criterion is weakly improved (Quantitative score = 1)
  - The indicators indicate that the achievement of the criterion is unchanged or neutral (Quantitative score = 0)
  - The indicators indicate that the achievement of the criterion is weakly degraded (Quantitative score = -1)
  - The indicators indicate that the achievement of the criterion is moderately degraded (Quantitative score = -2)
  - The indicator indicate that the achievement of the criterion is strongly degraded (Quantitative score = -3)

- In the above valuation scheme, scores of 1 or -1 are assigned when the assessment relies on an intuitive or logical justification. Measures of 2 or -2 are assigned when weak evidence is provided to substantiate or justify the assessment. Measures of 3 or -3 are assigned in the case of strong evidence, such as compelling modelling results or other substantiating evidence.

➢ Assessment weights: Each criterion is weighted based on importance, with the criterion weights summing to 1 (i.e. 4 criteria each having an assessment weight of 0.25). Within each criterion the defined assessment indicators can also be weighted if they are assessed individually (the indicator weights must also sum to 1 for each criterion). This analysis applies a collective assessment, so no individual weights are assigned.

➢ Multicriteria assessment: In the case of a collective assessment of indicators, a quantitative score for each class of assessment indicators is then multiplied by the the criterion weight. The outcome for each criterion is then summed across all criteria to produce a net assessment. Net assessments that are positive suggest that the rule change is likely to improve the attainment of the objectives and a negative assessment indicates that the rule change degrades the achievement of the objectives.

This analysis tests the Market Objectives. In respect of Clause 2.4.3 (a) and (b) (refer their statement on page 32) these factors would need to be assessed in favour for the Rule Change to be accepted. The items 2.4.3 (c) and (d) relate to the assessment of the Market Objectives by the Market stakeholders and the Market Advisory Committee and would inform the Market Objectives evaluation. The technical evaluation in Item 2.4.3(e) would provide technical and economic data in support of the assessment of the Market Objectives and would not need to be treated as a separate criterion or objective; it may provide strong substantiating evidence to justify a strong assessment of one or more assessment indicators.

3.3 Setup of the MCA model

Criteria and assessment indicators to be assessed are proposed in the following tabulated lists.

Core Criteria

(Related to the Market Objectives)

Criterion	Definition	Indicators
1. Efficiency [Criterion Weight = 1/7]	Economic efficiency, defined by the following measures: (1) allocative, (2) productive and (3) dynamic efficiency.	- Prices based on marginal opportunity costs - Production at minimum average total cost - Innovation and invention

Criterion	Definition	Indicators
2. Safety [Criterion Weight = 1/7]	Safety is the condition of being protected from harm, whether this is physical, financial or otherwise.	- Lost time injury rates - No unmanageable physical or financial risks that threaten the viability of the organisation
3. Reliability [Criterion Weight = 1/7]	The ability of the power system to continue to deliver power to customers of a defined and acceptable quality in routine conditions, and in defined exceptional conditions with an acceptable level of supply disruption.	- Expected unserved energy - Achieving targeted reserve margin - The availability of existing units - New investment timing
4. Competitive [Criterion Weight = 1/7]	The extent of rivalry between businesses when they strive for the same customer or market.	- A comparison of behaviour with an expected ideal based on an assumption that the ideal is perfectly competitive.
5. Non discriminatory market arrangements [Criterion Weight = 1/7]	Avoids discrimination in the market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions;	- Institutional or structural disadvantages that affect the ability to compete. - Prospect for adverse impacts on particular Market Participants.
6. Long-term Cost [Criterion Weight = 1/7]	Minimises the long-term cost of electricity supplied to customers from the South West interconnected system.	- Long-run delivered cost of electricity to customers inclusive of all wholesale, network, retail and other associated costs. - The cost of externalities on related markets and transactions.
7.Demand Management [Criterion Weight = 1/7]	Encourages the taking of measures to manage the amount of electricity used and when it is used	- The presence of infrastructure to facilitate load management incl. interval metering and control technologies, pricing structures and other incentives. - Participation by demand-side participants

Non-Core Criteria

(Related to further objectives that may be identified via section 2.4.3 of the Market Rules.

Criterion	Indicators
1. Implementability: [Criterion Weight = 1]	Comparing the prospective benefits with the practicality and cost of implementing the Rule Change Proposal.
2. Consistent with Participant Objectives	No additional criteria have been identified as part of this rule change proposal
3. Consistent with Market Advisory Committee	No additional criteria have been identified as part of this rule change proposal

3.4 Analysis of Issues

The following discussion is structured to address each of the identified criteria. An aggregate assessment is presented in section 3.4.9.

3.4.1 Efficiency

Efficiency measures whether scarce resources are used in their best or optimal way to satisfy the wants and needs of society. Economists typically define three measures of efficiency – allocative efficiency, productive efficiency and dynamic efficiency; specifically:

- **Allocative** efficiency –This is attained when welfare is maximised, that is, when no one can be made better off without someone else becoming worse off. A market outcome is considered allocatively efficient when realised prices equal the marginal opportunity costs associated with market participation.

- **Productive** efficiency –This can be applied to both the short and long term and reflects the production of output at minimum average total cost. Differences in average total cost between time-scales are linked to investment behaviour.

- **Dynamic** efficiency –This relates to changes in customer preferences and choices, and takes into account the pace and extent of technological change which occurs via product and service innovation.

In the context of this rule change proposal, relevant assessment indicators that can indicate whether the rule change improves market efficiency include

- the alignment of prices (and penalties) with marginal opportunity costs

- the timeliness of investment signals that incentivise investment in assets that will minimise the long-run average total cost of electricity; and

- the presence of incentives to encourage innovation, invention and other technological progression.

A test of whether the current capacity refund mechanism is efficient requires an assessment of whether the penalty provisions are aligned with the costs that are borne by Market Customers to address an unexpected shortfall of capacity. The logic is that an efficient penalty should recover the costs associated with the impact of undesirable conduct, and therefore the costs that are caused when anticipated and planned-for capacity is not made available. The concept of undesirable conduct implies behaviour that is contrary to defined rules, or to an agreement or contract, and also that is an outcome of intention or deliberate action. This latter point tends to disqualify accidents or unanticipated events from conduct that is deemed undesirable. When the payoff to undesirable conduct can exceed the expected penalties, an incentive problem may occur, requiring some penalty mechanisms to have provision for additional punitive measures to ensure undesirable conduct is discouraged. This punitive component may escalate based on the number of conduct events that have previously been identified as a concern.

The costs of unexpected capacity shortfalls will be greater in the hot or peak seasons because the system operating margins are reduced and higher cost resources operate at the margin, including the risk of customer load shedding. Both the current refund mechanism and the effect of the proposed rule change can therefore be assumed to be directionally efficient, in the sense that penalties and seasonal caps are greatest in the hot and peak seasons.

The energy unit costs of unexpected capacity shortfalls would likely diminish over time when the expected duration of a shortfall is sufficiently long so as to provide greater opportunities for solutions to be made available. When an extended capacity shortfall is long enough to allow a Supplementary Reserve Capacity auction, for example, the costs of resolving the shortfall would almost certainly be lower than in the immediate period before the shortfall can be addressed, when potentially higher costs in the wholesale energy market may be caused due to the increased scarcity of available capacity at this time. Insofar that the proposed Rule Change 35 causes penalties to flatten during the latter part of a season, it could be argued that the rule change again is directionally efficient. It may even be superior overall if late season risks are normally lower than mid-season risks.

With respect to conduct incentives, Griffin makes the point, and MMA concurs, that the current rules provide inefficient behavioural incentives over the extended duration of a long forced outage event. In particular, for forced outage events lasting a whole capacity year, the current refund mechanism caps the annual penalty after approximately 6 months for an event that starts on October 1 of the capacity year. Over the cold season, this means that the relevant electric facility has no additional penalty, and therefore a diminished incentive to make itself available until the start of the next capacity year. Although the cold or intermediate season typically features more than sufficient reserve capacity, significant costs could be caused if extended outages relate to base or intermediate load generation. However, the generator will bear most of these costs if the lost output was already bilaterally contracted and the STEM remains a very small portion of the energy traded. Thus the loss of this incentive does not impose a substantial risk on the WEM.

The rule change proposal corrects for any inefficient conduct incentive by ensuring that a significant cost can still be associated with an extended duration capacity shortfall event during the latter part of a capacity year.

In terms of **allocative efficiency**, the proposed rule change therefore appears to be an improvement on the current rules, at least in terms of being directionally consistent with an efficient penalty mechanism. What is unknown however, is whether the precise magnitude of the penalties at different times and scenarios is efficient, both in the case of the current rules, and with the proposed rule change. No evidence has been made available to assess this, and no economic logic has been provided in support of the level of the proposed seasonal caps. Griffin has argued that reducing the Capacity Payment Refunds when they would have no effect on recovery of constriction delay would reduce wholesale costs but there would be no change to economic efficiency if there is no change to recovery of construction delay. The change in the Capacity payment refunds represents and economic transfer within the market, not a change in external costs.

MMA notes that without this economic analysis, it is possible that by lowering capacity payment refunds for extended outages, the proposed seasonal caps may have the effect of under-recovering true costs, therefore potentially raising the net cost of capacity to the market. Indeed the insertion of capped periods during the hot and peak seasons may distort outage maintenance activities for peaking plant from an efficient plan and thereby reduce allocative efficiency to a small extent.

In terms of **productive efficiency**, no analysis or evidence has been provided to substantiate the case that the proposed seasonal caps will minimise the long-run average total cost of electricity. Although Griffin suggests that new entrant base-load plant is disadvantaged by what it claims is an excessive penalty associated with the current capacity payment refund mechanism, the materiality of this impact on investment decision-making has not been demonstrated.

In consideration of these assessment indicators, neither Market Participants, nor MMA, have identified any significant impact of the proposed rule change on innovation or invention. Further, no evidence has been provided that the proposed rules will deliver timely investment in an optimal technology mix of new capacity. MMA does not therefore recognise a justification that the proposed rule change impacts on the **dynamic efficiency** of the market.

Overall, we assess that the major impact is through allocative efficiency and how it would affect the incentive to return plant to service as quickly as possible toward the end of a season when the Capacity Payment Refund is capped. The risk of some extended outages gives a slight negative assessment.

Quantitative score measuring the impact of the rule change on the efficiency criterion:

-0.5 (slight negative impact)

3.4.2 Safety

Safety is the condition of being protected from harm, whether this is physical, financial or otherwise.

In the context of this rule change proposal, relevant assessment indicators that can indicate whether the rule change improves safety include the impacts of the change on lost-time injuries, or impacts that may result in unmanageable financial or business risk that may have the effect of threatening the viability of the organisation.

Griffin suggested that the current rules relative to the proposed rule change imply a greater threat to safety; it states without explanation or evidence that inefficient financial penalties for new entrant generators that have not yet commissioned plant may potentially lead to work practices that result in less stringent safety and reliability standards[1]. Other market participants, in their submissions in relation to this rule change, did not identify any safety concerns.

MMA has not identified any material impact of the rule change on the safety objective, whether this is considered in terms of physical safety, or in terms of the imposition of unmanageable business or financial risk that could affect the viable and sustainable operation of a market participant's organisation. MMA does not agree that a market participant would choose to compromise the safety of workers as a consequence of the current penalty provisions.

Quantitative score measuring the impact of the rule change on a safety criterion:

0 (neutral or no impact)

3.4.3 Reliability

Reliability in the context of electricity supply typically refers to the ability of the power system to continue to deliver power to customers of a defined and acceptable quality in routine conditions, and in defined exceptional conditions. Reliability levels are normally prescribed by regulation, and may be different from the competitive markets preference for reliability. Prescribed reliability standards may therefore be different from efficient levels of reliability.

In the electricity market, indicators of reliability can include the short-run objective that all existing electric facilities, including demand-side response, have working incentives to make their capacity available, with planned outages scheduled for the least costly periods, and forced outages minimised by aligning operating and maintenance expenditure with the expected revenues attributable to the returns to capacity. In the long-run reliability can be measured by the alignment of new investment signals for different classes of plant with the market's temporal requirement for installed capacity, as defined by regulation. This requires a consideration of the total revenues that can be earned by an electric facility

[1] Page 11 of "Amended Rule Change Notice, Title: Capacity Refund Mechanism – New Generators", Ref: RC_2008_35, Standard Rule Change Process, Date: 05 January 2009, Independent Market Operator.

from all sources within and beyond the market, the market's preference and valuation of risk, and the costs associated with building, commissioning and operating new capacity.

Griffin contends that the current refund mechanism may diminish incentives to make capacity available during the latter part of an extended forced outage. This is because the current refund schedule imposes an annual cap that can stop the imposition of penalties after 6 months of an outage that commenced on October 1 of a capacity year. The result is that during the cold season, capacity that has been unavailable since the start of the Capacity Year receives no penalty from unavailability, imposing the risk that reliability levels may not be sufficient due to distorted signals. The proposed Rule Change seeks to correct this by applying seasonal caps that proportion and allocate parts of the annual cap across each capacity season, ensuring that penalties can be applied across each season of the capacity year. In doing so, and as an outcome of preserving the current Refund Table, the proposed seasonal caps have the effect that within each season, cumulative penalties can aggregate and hit the cap before the end of the season such that during the latter part of each season there is no penalty for undelivered capacity. Without analysis that defines the financial cost of unexpected capacity shortfalls, it is not known whether the proposed seasonal caps actually improve the efficiency of the current Refund Table. What is known is that the true costs of unavailable capacity are greatest during the hot and peak seasons, suggesting that from a reliability perspective, that a seasonal cap may diminish reliability objectives once the seasonal caps exhaust the requirement for Capacity Payment Refunds.

In consideration of longer-run reliability objectives, Griffin has not demonstrated that the proposed seasonal caps will provide investment incentives to deliver a schedule of new capacity that provides an optimal mix of technology with timings that meet reliability targets. Nor have submissions by other Market Participants provided justification on these terms either in support or otherwise of the proposed Rule Change. Without analysis or evidentiary support, MMA cannot conclude the proposed Rule Change either supports or diminishes this longer run reliability indicator. Further, in recognition that the profile of Capacity Payment Refunds in the current rules provides some temporal flexibility in the management of penalty risk prior to the hot season, MMA is of the view that the degree of risk available to new entrant generation is manageable.

MMA therefore does not agree that the proposed Rule Change has been demonstrated to improve the market's reliability objective. Recognising that the most critical seasons for the availability of capacity are the hot and peak seasons, given that the proposed rules have the effect of capping capacity payment refunds during these critical seasons, MMA notes that the proposed rule changes may diminish reliability late in these seasons.

Quantitative score measuring the impact of the rule change on reliability criterion:

-1 (weak negative impact on the criterion)

3.4.4 Competition

Competition is related to the extent of rivalry between businesses when they strive for the same customer or market. Indicators of competitiveness in organised electricity markets include a comparison of behaviour with an expected ideal based on an assumption that the market is perfectly competitive. Typically it is measured by comparing bid/offer behaviour with the marginal opportunity costs of market participation. Offers below marginal costs, for example, can foreclose competition and discourage new market entry. Offers above marginal cost are indicative of market power, and indicate extra-normal profit. Behaviour that is identified as potentially anticompetitive is typically deemed a problem only if it has the effect of changing market outcomes so that they move beyond an acceptable competitive range for prices and efficiency. Competition assessments often therefore feature a conduct and impact review of behaviour.

Griffin, in its rule change proposal, did not explicitly identify any impact of the proposed rule change on the market's competition objective. Although Griffin suggested that new entrant generation is treated in a discriminatory manner by the current capacity payment refund mechanism, noting that the mechanism does not reasonably accommodate the greater commissioning risk of new entrant base-load plants, it did not make the case that this risk had the effect of diminishing competition.

Neither Griffin, nor the submissions of other market participants have suggested that the current rules have diminished the extent of rivalry between businesses as a consequence of the current capacity payment refund mechanism, nor has there been a substantiated case that these current rules are causing capacity costs to exceed a normal competitive level.

MMA does not consider that the proposed rule change has been demonstrated to have a material impact on the market's competition objective.

Quantitative score measuring the impact of the rule change on the market's competition criterion:

0 (neutral or no impact)

3.4.5 Non-discriminatory market arrangements

Discrimination in a market or industry typically indicates that one or more classes of market participant have an institutionalised or structural disadvantage in their ability to compete with other market participants in a manner that is separate from disadvantages that may relate to the economic costs of their production technology. The concept can also apply at an asset or transaction level such that one or more classes of asset or transaction have a similar institutionalised or structural disadvantages in the ability with which they can compete with other classes of asset or transaction.

As part of its rule change proposal, Griffin argues that the current regime discriminates against capital intensive base-load equipment relative to open cycle gas turbine technologies and therefore biases the market in favour of peaking plant, which would not be efficient. Griffin argues that the greater complexity and construction time associated with implementing these plants increases the probability that such plants will be delayed in commissioning, and therefore imposes an uneven penalty risk via the capacity credit refund mechanism. Although the current refund mechanism is equally and equivalently applied to market participants irrespective of their status as a new or existing participant, and irrespective of their investment in either a base-load or peak-load plant, Griffin's contention is that it is the impact of the mechanism that is uneven and biased given the technology of the new investment. Griffin is not of the view that the application of a penalty is inappropriate, but rather that the level of the penalty does not adequately accommodate the different risks and circumstances of alternative generation technologies, with the effect that new base-load plants have a disproportionate financial risk that could affect investment decision-making in a manner that discriminates between technologies, and between existing and new entrant plants.

The submissions of other market participants do not support Griffin's claims. Alinta's submission suggested that the proposed rules may in fact bias penalty arrangements in favour of peaking units. 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 infra-marginal revenue at wholesale market prices. Indeed, this inframarginal revenue[2] provides a major source of fixed cost recovery for these units, thereby providing an ongoing basis for recovering initial development costs. Peaking units are much more reliant on capacity payments to recover fixed costs, and are typically the marginal units when they operate, providing limited inframarginal revenue to recover development costs. Although the development of a base-load unit may feature more development risk than a peaker, this risk is manageable, and development can be scheduled to minimise the likelihood of a delay affecting the hot and peak season.

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 does not agree that it is necessarily the case that the current rules discriminate against new entry base-load developments. No data has been provided to show that the stated development risks cause costs to increase in a manner that undermines investment behaviour, nor that current market revenues would fail to provide a sufficient and normal economic return for these affected units once commissioned.

Quantitative score measuring the impact of the rule change on the market's non-discrimination criterion:

0 (neutral or no impact)

[2] Inframarginal revenue refers to the difference between the plants' short-run marginal costs and the price it receives as revenue

3.4.6 Long-term cost

The minimisation of long-term costs to customers is an alternative indicator of economic efficiency, but is also related to the objective of competitive market conditions. In the context of organised power markets, it relates to the total costs that are realised by customers, including all wholesale settlement costs, as well as related costs attributable to the retail and contract markets, and also network costs.

The objective of minimised long-term costs to customers requires as co-requisite conditions:

1. productive efficiency in the technology that delivers market outputs, including timely investment in those assets that will minimise the long-term costs of production; and

2. a competitive market such that market participants transact on the basis of marginal opportunity costs, thereby producing market outcomes that deliver normal (efficient) profit.

This objective therefore overlaps with other Market Objectives, but extends from these somewhat by explicitly considering cost impacts on customers, and therefore also the interactions that the wholesale market may have on related markets, such as the retail and bilateral contract markets, therefore capturing potential externalities that the wholesale market design may have on these related markets.

No evidence has been provided to demonstrate how the proposed rule change would impact the long-run costs to customers. MMA notes that although it is possible that the introduction of seasonal caps may have the effect of lowering the expected costs of building a new entrant generator, it is also the case that the consequence of any realised lower costs due to delayed commissioning may be greater energy costs due to expected capacity being unavailable. Without evidence it is therefore unclear whether the proposed rule change will lower or raise expected long-run costs to customers arising from the development of base load plants.

However, there is the small effect that delays in return to service of peaking plant arising from the seasonal caps would increase the risk of a call on Supplementary Reserve Capacity that may not be recovered from Capacity Payment Refunds. On an expected value basis there would be some increase in SRC costs. Thus we have assessed a slight negative impact.

Quantitative score measuring the impact of the rule change on the long-run cost to customer criterion:

-0.5 (small negative impact)

3.4.7 Demand Management

The objective to encourage the taking of measures to manage the amount of electricity used and when it is used refers to an objective to improve demand-side response, and demand-side participation in the market.

In competitive wholesale energy markets, demand management incentives are maximised when the demand sector has access to technologies to control the level and profile of consumption, metering technologies to track controllable behaviour, and pricing signals that combine with these other factors to deliver incentives to control consumption in a manner that aligns the marginal opportunity cost of voluntary load management with system marginal prices (inclusive of delivery costs).

Market Participants have not advised of any concerns that the proposed rule change will adversely impact demand side management or demand response.

MMA notes that demand management initiatives typically do not have the same logistical complexities that feature in decisions to offer existing or new generation capacity to the market, and therefore would be less likely than a generation facility to be affected by the seasonal caps on capacity payment refunds. MMA has not identified any significant impact of the rule change on incentives to offer demand management initiatives to the market.

Quantitative score measuring the impact of the rule change on the demand management criterion:

0 (neutral or no impact)

3.4.8 Implementability

This objective refers to the practicality and cost of implementing the change. Indicators of implementability can include the financial cost of changes to systems, processes and technology, as well as the demand on resource capacity, and the consequences of resource usage for other projects, changes or responsibilities that may need to be deferred, de-prioritised or foregone.

Market Participants, in their submissions in relation to this rule change, did not identify any implementation concerns.

MMA notes that any change to the financial settlements infrastructure of the market will necessarily require a system, procedural and staffing solution to effect the change. Moreover, changes of this nature can affect out-of-market contracts and agreements that may feature linkages or instruments that relate or depend on the financial settlements outcomes of the market. There is a potential therefore that a reintroduction of seasonal caps may have some impact on existing contracts or agreements that may impose a practical concern for affected counterparties. Given that these potential concerns were not identified or demonstrated by participants in their submissions, MMA considers that these concerns may be immaterial or non-existent. Further, MMA has not been made aware that the Rule Change will impose a significant implementation cost, or require an unmanageable draw on staff resources.

Quantitative score measuring the impact of the rule change on an implementability criterion:

0 (neutral or no impact)

3.4.9 Overall Assessment

Figure 3-1 presents the results of the multicriteria assessment.

Figure 3-1 Multicriteria Assessment of the Rule Change

Criterion	Weighting	Assessment	Score	Weighted Score
1. Efficiency	14.3%	Slight effect due to delayed return to service of peaking plant	-0.5	-0.071
2. Safety	14.3%	No effect on physical safety	0	0.000
3. Reliability	14.3%	Some reduction in late season supply relaibility	-1	-0.143
4. Competitive	14.3%	No or Neutral Impact	0	0.000
5.No Discrimination	14.3%	No or Neutral Impact	0	0.000
6. Long-term Cost	14.3%	Slightly increased risk of SRC cost	-0.5	-0.071
7. Demand Management	14.3%	No or Neutral Impact	0	0.000
SCORE	**100%**			**-0.041**
Implementation		No or Neutral Impact	0	0
Total Assessment	**Core**	**Weakly Negative**	Weighted Average	**-0.041**
	Non-Core	**No or Neutral Impact**	Weighted Average	**0.000**

Overall the rule change proposal is assessed in terms of the core criteria to be very weakly negative, meaning that the proposal is expected to slightly diminish the achievement of the Market Objectives.

The overall score of -0.04 out of a possible range of -3 to +3 for the core criteria is an outcome of a neutral or nil impact on most of the Market Objectives. Three Market Objectives scored an impact that was not neutral. The weak scores were assessed because the arguments were considered valid, intuitive and logical, but that no evidence or quantitative analysis was available to confirm the magnitude of the effects on the Market Objectives.

The indentified non-core criteria included just one objective, that relating to implementability. The score for this objective was neutral (0), indicating that there were no identified and substantiated costs or benefits associated with the implementation of the proposed rule change. Since the Market Objectives are not better met by the proposal, the implementability does not influence the assessment.

3.5 Impact of Weights for Criteria

Given that no Market Objectives is significantly improved by the assessment, any combination of weights applied to the Criteria would yield the same overall result.

4 CONCLUSIONS

Based on the analysis in Chapter 2 and Chapter 3, MMA does not support the Rule Change 35 because it makes no significant improvement in meeting the Market Objectives and has scope for a slight detrimental effect on supply reliability.

MMA considers that seasonal caps might be useful to spread the incentive to manage performance over the year but it has not been established that seasonal caps would materially reduce the financial risk of delayed commissioning in a way that balances the costs of recovery from project delays, the costs of SRC and the costs imposed on customers from inadequate reliability. Indeed there is the risk of an unintended consequence of reducing the incentives for return of peaking plant from outages later in the seasons when the cap on Capacity Payment Refunds would be effective. This would reduce reliability and increase the risk of the need for Supplementary Reserve Capacity.

In view of the concern about successive changes to the processes around the Refund Table and the insufficient evidence of the efficiency or otherwise of the current arrangements, MMA considers that there is no immediate need to reimpose seasonal caps without reference to a reliability assessment and consideration of the impact of lead time on the refund processes. It is likely that the current refund profile that caps out between 5.5 and 10.3 months depending on the start time is not optimal but nor is it significantly inefficient to warrant the changes proposed by Griffin Energy.