Wholesale Electricity Market
Rule Change Proposal Submission Form

RC_2010_29

Submitted by

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Submission

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

Overview

Energy Response (ER) supports the IMO's draft decision in all recommendations excluding Issue 4. All other issues enhance the reliability and operability in providing Demand-side Response (DSR) as a dispatchable form of capacity, to help manage supply and demand.

The methodology used to value dispatchable DSR capacity will have implications on this industry's market size, relative value against other forms of capacity, and more broadly on the diversity and reliability of our isolated electricity system. ER posits that the proposed methodology will have unintended negative consequences on these factors.

ER supports that all IMO recommendations of this Rule Change be accepted, excluding those pertinent to Issue 4, and that Issue 4 be referred to the Reserve Capacity Mechanism (RCM) Review, for a more extensive examination of alternative methodologies.

The results of the RCM review are very relevant in determining the value of dispatchable DSR capacity, particularly as the proposed methodology seeks to align it to the relevant unadjusted peak capacity cost.

Proposed Methodology

Aligning the unadjusted Individual Reserve Capacity Requirement (IRCR) to the Relevant Demand (RD) sends a signal to the market that random, uncontrolled peak demand reduction is more valuable than measurable dispatchable capacity.

This is because the vast majority of loads within the SWIS are considered Temperature-Dependant loads (TDL). Thus, under the proposed methodology, a reduction in peak load, as measured by IRCR, would generally be compensated at a rate 40% higher than the provision of the same capacity as a dispatchable reduction in response to System Requirements. When faced with a choice between both products, customers will invariably choose to reduce their IRCR component.

This must be an unintended consequence, as DSR is clearly more valuable: it is predictable, controllable, and, due to the penalties for non-performance, reliable.

Like all other capacity suppliers, a DSR supplier must commit to a fixed level two years out from when it is required; failure to meet this commitment will result in the forfeit of a significant security deposit. Ongoing provision of capacity is incentivised through direct capacity payments, which is important in planning for any capacity shortfall. The IMO has information on the terms of DSR capacity, and this rule change's requirement for declaration of forced outages can be built into effective planning. Any shortfall in capacity can be recovered in the same manner it would be recovered from any other capacity supplier.

Perhaps most importantly, DSR is a dispatchable service. It can be used to manage the system during capacity deficiencies, as illustrated by the dispatch of DSR during the recent emergency operating state. This was brought about by gas supply constraints; the second instance in three years. However, DSR could respond to any number of unidentified capacity requirements in the future. It is simplistic to assume that these capacity requirements will always align with peak demand.

In contrast, programs that target a reduction in IRCR cannot be relied upon year by year. They are unmonitored, and rely on the voluntary reduction in demand during intervals which the program operator estimates will be high peaks. System Management does not know how sophisticated these estimates are, or the limits which apply to curtailment by providers in the program. Hence the IRCR reduction can vary widely and unpredictably year to year.

The operator of an IRCR reduction program must forecast the parts of the year in which the highest loads are likely to occur, allocating their budget of curtailment periods across the most likely candidates. If unexpectedly high loads were to occur towards the end of summer, the operator may be unable to respond, having already used the curtailment periods available to them under their agreements with providers. In that case, nothing could be recovered from the program operator, and any Supplementary Reserve Capacity could come at much higher cost, as the capacity shortfall would occur from <u>unexpected</u> high demand.

ER does not seek to discount active peak demand management. On the contrary, we see IRCR reduction and dispatchable DSR capacity as two distinct market services – each important in its own right. However, using the same metric to determine peak demand and dispatchable DSR will cannibalise dispatchable DSR capacity, to the detriment of market efficiency, fuel diversity and system reliability.

ER recognises that when peak demand reduction coincides with a DSR dispatch, the value of the DSR capacity may be overstated, as System Management may have already accounted for the expected relevant incremental load reduction. *DSR capacity should fairly represent the <u>expected</u> load that would have occurred had a dispatch request not been made for that program.*

The value attributed to peak demand reduction must be considered alongside any review of the value of dispatchable DSR capacity, an issue which is introduced in the RCM review.It is not equitable that the effect of peak demand management, which only covers around 2.5% of the total DSR program availability, should lead to a discount in the value of the DSR capacity for the entire capacity cycle. As part of the RCM review, it is worth considering some mechanism that captures IRCR reduction programs. This would provide more reliable estimates of peak demand reduction in the next year, and allow an avenue for Reserve Capacity refunds to apply during those periods where DSR component loads were actively managing their peak demand.

Profile methodology

As stated, *DSR capacity should fairly represent the <u>expected</u> load that would have occurred had a dispatch request not been made for that program.* For capacity valuation, there should be an accommodation for the relevant seasonal value of that capacity; as there is with generation capacity.

Enernoc's alternative methodology, described in PRC_2011_01, provides an interesting alternative to the static baselines previously contemplated. It is more consistent with the treatment of generation capacity, because it can more closely reflect reduction against expected load with hourly and seasonal adjustments.

It is in the long-term interest of this industry that the capacity value reflects the value it provides as an alternative to generation capacity. At the same time, ER recognises that any changes to the existing systems and rules to accommodate a more flexible valuation must bring a net economic benefit to the market.

The framework for testing, capacity valuation, capacity refunds, security deposit return, commissioning and a host of other inter-related aspects need to be defined in order to perform an economic valuation.

ER recommends the described profile methodology should be included in the RCM review for evaluation. We also request that System Management provide a presentation on the calculation of load forecasts. This will allow a better understanding of how the divergent methodologies perform against *'expected load that would have occurred had a dispatch request not been made for that program'.*

Interim methodology

DSR programs currently have their component capacity value updated annually, with a reasonable estimate on these values in late March. The current ambiguity in the methodology to value these components is delaying fulfilment of DSR programs for the next capacity cycle. While other market participants might assume that DSR commissioning is not technically complex, in fact the registration and commissioning of these programs require the interaction with potentially hundreds of different parties. As such, an acceptable methodology must be settled on for the next capacity cycle, as soon as possible.

The level of sophistication of this electricity market requires a great deal of education for our providers. Also, as most providers have long-term contracts, it is not suitable to change the methodology in increments. ER requests that any substantive change of methodology be comprehensively reviewed, with the intent of arriving at a stable, long-term solution.

The existing Relevant Demand calculation is the most appropriate methodology for now, while a long-term solution that fairly values DSR capacity is being sought. It provides a robust method, where load levels across four different months are used to estimate the level of capacity that would be available if the program were to be dispatched in the next summer.

For this methodology to be reflective of the level of capacity, the clause which allows for substitution due to maintenance must continue to be applied, where the provider can prove that its capacity value is lower than can reasonably be expected for the next year.

Substitution

The IMO already is able to determine what constitutes maintenance under the existing methodology. We propose the IMO use its own judgement to ensure the capacity value is reflective of what a load is likely to be available to dispatch.

Energy Response has undertaken analysis of the publicly available market data to predict the pertinent dates that are likely to apply for both Relevant Demand and IRCR calculation. They are mentioned below, along with the significance of each:

Relevant Demand

(a) 24 December, Christmas Eve

(b) 28 January, Cyclone Bianca and catastrophic storms in the wheatbelt resulting in power supply interruption in that area

(c) 28 February, gas supply disruption due to Cyclone Carlos resulting in DSR program dispatches and some 55,000 disconnections.

(d) 1 March, as above

IRCR

(e) 16 February, System Management conducting tests on some of our facilities;

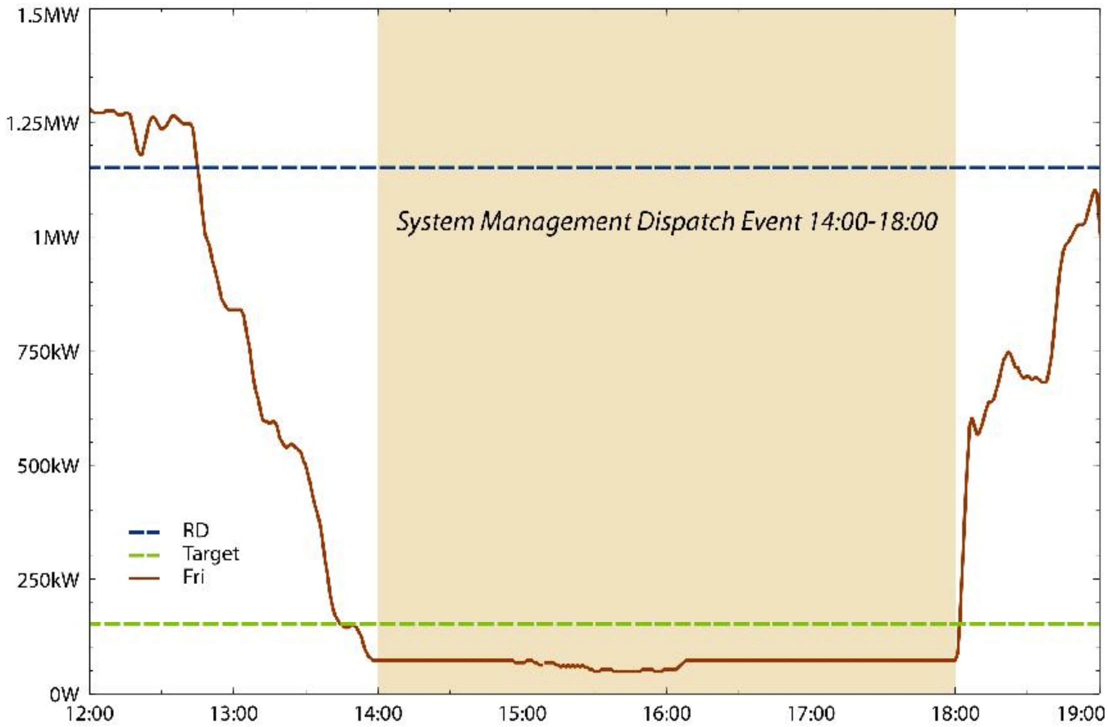
(f-h) 24,25 and 28 February, refer to (c) above

As noted above, there are exceptional circumstances this year where many of the component loads within the next capacity cycle's program were operating at a level under what they can reasonably be expected to deliver next year.

It is not appropriate to assume that a dispatch event is highly probable on Christmas eve, when system demand was a little over 3GW, when many industrial consumers are already on Christmas shutdowns. Nor appropriate to assume that consequential network outages due to storms can be anticipated during dispatch events next year.

Given that over half of the dates listed above happened to occur on days when our program was dispatched, there must also be an allowance for load ramp-down and ramp-up periods, outside of the System Management dispatch period. Figure 1 (below) shows a concrete example of ramp-up and ramp-down, taken from 1 minute meter data from an industrial site which participated in the dispatch event of 25 February 2010. System Management dispatched this site from 14:00 to 18:00. The load shown from 12:00 to 12:30 is typical for the site. It started ramping down at around 12:45, and did not ramp back up to normal production levels until around 20:00. This is fairly typical behaviour for industrial facilities, although some take longer. If the periods from 12:30 to 14:00 and from 18:00 to 20:00 were to be included in the Relevant Demand calculations, then the site's demand would be underestimated. This would be an unfair penalty for a site which was only doing what System Management requested.

Figure 1



For these reasons, a static baseline must have some flexibility to provide substitution for events such as those described, so that the level of capacity credits more accurately represent the program's dispatchability under normal operating circumstances in the following year. A move to a profile baseline would undoubtedly remove this requirement.

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

The proposed methodology described in Issue 4 of this Rule Change proposal results in the effect on the following market objectives

Market Objective	Assessment	Description
A	Inconsistent	Does not encourage economically efficient or reliable supply of capacity services. Economic efficiency requires the participation of both supply and demand capacity. Peak demand reduction is not a dispatchable or

		reliable capacity service, thus its promotion at the expense of dispatchable demand capacity will provide for unmitigated generator market power.
B	Inconsistent	Related to the capacity market, refer above, will not facilitate efficient entry of new competitors, by limiting the market size of dispatchable demand capacity.
C	Inconsistent	Alignment of IRCR and RD discriminates against DSR capacity, relative to other capacity supplies. Capacity is not only required during peak demand times, and a volatile (equiv. 6hrs) measure of such, risks understating its value when dispatched.
D	Inconsistent	DSR capacity expands the amount of resources available to the market, increases competition, helps reduce prices to consumers and enhances reliability. Measures such as those proposed, that would limit this market, without consequent reliable reductions in peak demand will increase the long-term cost.
E	No change	The proposed methodology still provides an incentive to manage demand. However, it incentivises managing peak demand over providing dispatchable demand reduction.

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

Issue 4:

More information is required on the process and conditions for substitution due to System Management request to assess the economic impact in the next capacity cycle.

In the capacity year beginning October 2012 we foresee significant difficulties in fulfilling our capacity obligations for that capacity cycle with the proposed methodology. This is due to the consequence of severely limiting the available market by excluding any user that actively manages their peak demand, or has an unreflective value of their dispatchable capacity.

Failure to register ER's additional capacity in that capacity cycle will result in losses of approximately $4 million through forfeiture of the relevant Security Deposit.

In the long term ER anticipates a contraction of the dispatchable DSR Capacity market.

The methodology is structurally similar to the existing rules. IT costs would be immaterial.

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

The methodology is similar to the existing rules. Implementation could be immediate.