Public Workshop: Relevant Demand Methodology Background Documents

Location: Level 2, Meeting Room 12, Perth Convention Exhibition Centre

Date: Friday, 8 April 2011

Time: 2.00pm – 4.00pm

RULE CHANGE PROPOSAL: CURTAILABLE LOADS AND DEMAND SIDE PROGRAMMES (RC_2010_29)

REVISED STATIC BASELINE RELEVANT DEMAND METHODOLOGY

The IMO's proposed revisions to the current RD methodology

An overview of the current issues with the measurement of the performance of Curtailable Loads as presented in the IMO's Rule Change Proposal: Curtailable Loads and Demand Side Programmes (RC_2010_29) is presented below:

Overview of Issue: The Rule Change Proposal: Demand Side Management - Operational Issues (RC_2008_20) introduced a new concept for measuring the curtailability of Curtailable Loads (CLs). This is known as the Relevant Demand (RD) level. The RD level determines the median value that a CL consumes during 32 Trading Intervals of highest demand during the preceding Hot Season, reflecting a normal operating level during the intervals when the Demand Side Programme (DSP) is most likely to be dispatched.

The Market Rules also give a CL/DSP the ability to perform maintenance over these peak intervals without this reducing the corresponding RD level for the Facility. The IMO considered in its Rule Change Proposal that the exclusion of maintenance from the calculation gives a dual incentive to Market Participants to perform maintenance during intervals they assume will be IRCR intervals[1]. For example a Market Participant can currently attempt to reduce its load over intervals which it considers will be Peak Trading Intervals. Note that the IRCR and RD intervals are likely to be similar intervals and as such a Market Participant's IRCR are likely to be reduced. To minimise the cost of these reductions if a Market Participant performs maintenance on a Facility over these intervals, that Market Participant can also apply to the IMO to exclude these intervals resulting in a higher RD level than they would otherwise have had calculated. As a result the Market Participant not only has a reduced IRCR cost but also received a higher RD level and so receives a higher Capacity Credit payment in the following year.

As noted above the RD level is intended to reflect the normal operating level during intervals when the DSP is most likely to be dispatched, however in the case outlined above the RD level will not be representative of this peak load operating level. The IMO therefore recommended to the MAC that the ability to exclude Trading Intervals where maintenance was being performed be removed from the Market Rules. The IMO considered that there is already a payment incentive in place to reduce consumption over peak periods in the IRCR calculation.

The IMO noted in its proposal that if a Facility was undertaking maintenance or experiencing an unplanned outage during any of the 32 Trading Intervals of highest demand used in the RD calculation, and these do not match up with any of the 12 IRCR Trading Intervals, then the Market Participant would not receive the benefit of a reduction in its IRCR and would have a lower RD level calculated (resulting in a

[1] The 12 peak Trading Intervals during the Hot Season preceding the initial calculation.

reduced level of Capacity Credits being assigned). As a result the IMO commissioned Data Analysis Australia (DAA) to consider the use of the IRCR Trading Intervals as the basis for the RD calculation. DAA's analysis found that the use of the IRCR intervals would produce a more reliable result which better reflects the normal operating level during intervals when the DSP is most likely to be dispatched. Further details of DAA's analysis and the MAC's subsequent discussion are available on the IMO webpage: http://www.imowa.com.au/MAC_28

The IMO noted that a separate issue identified in the measurement of the performance of CLs is that the Market Rules do not currently contemplate the ability for a Facility to be oversubscribed. As such the measurement of these oversubscribed Facilities is also not accounted for. The following options to account for oversubscribed facilities were identified by the IMO, either to:

1. Measure the reduction of each individual Load compared to its individual RD level; or
2. Measure the aggregated DSP as a single Facility with a RD Level based on the sum of the comprising Loads.

Currently a reduction of a DSP is measured for those Loads which the DSP directed to curtail. This is similar to the first option presented above and results in only curtailment of output being associated with the DSPs performance and not any increases in load which may have occurred by Loads within the DSP (outside of any directions having been issued). The IMO considered that it is appropriate that the DSP is responsible for the level of operation of the DSP as a whole, which would include any natural movement in Loads above and/or below the DSPs RD level which were not as a result of directions having been issued.

Following the outcomes of DAA's analysis which found no significant difference between the two options, the IMO did not consider it is necessary to calculate the RD level for each individual Load as this would create unnecessary operational overhead and not improve the RD levels ability to reflect the normal operational level of the DSP during required intervals.

The MAC's Agreed Outcome: The MAC agreed that:

- The RD level calculation methodology should be changed to be calculated on the IRCR intervals;
- The exclusion due to maintenance, clause 4.26.2C(d) should be removed from the Market Rules; and
- The RD level should be calculated based on the aggregated output of the DSP, and not by aggregating the RD of each CL associated with a DSP (11 August 2010 meeting).

Proposed Solution: The IMO noted in its proposal that the solutions to issues 1 and 2 (which will ensure that only the DSP is visible to the market and not the comprising loads) combined with the RD level being calculated based on the aggregated output of the DSP, and not by aggregating the RD of each CL associated with a DSP will ensure that the correct measurement of the DSP as a whole[2]. The IMO contended that this will ensure that a DSP is treated similarly to other Facilities (by measuring consumption at an aggregate level) with regard to how it satisfies its Reserve Capacity Obligations and simplifies the measurement of the DSP's consumption.

Issues raised during first submission period

A summary of the comments and issues raised by interested parties during the first submission period for RC_2010_29 along with the IMO's response as presented in its Draft Rule Change Report is provided below:

[2] For further details of the IMO's proposed solutions to issues 1 and 2 refer to the Rule Change Proposal available on the following webpage: http://www.imowa.com.au/RC_2010_29

Clause/Issue	Submitter	Comment/Change Requested	IMO's response
Calculation of RD - dynamic vs. static baseline methodology (Issue 4)	Alinta	Notes that RC_2010_12 would amend the Market Rules to measure whether or not a CL or DSP has met its Required Level by comparing actual post dispatch consumption to its RD less CCs associated with the CL or DSP. Irrespective of whether RD is measured by IRCR or 32 Peak Trading Intervals, this method risks misrepresenting the amount of capacity actually provided by the CL or DSP where actual pre-dispatch consumption is lower than the RD of the CL or DSP.	The IMO notes that this issue is associated with the use of an RD value that has been determined using a static baseline. The IMO notes that the changes proposed under RC_2010_29 around the determination of a DSP's RD are twofold: • firstly, to remove the issue associated with double payment of DSPs; and • secondly, to ensure that the performance of DSPs can be better measured. As agreed by the MAC during the August 2010 meeting, the IMO has proposed that the RD level be a static baseline measure, calculated on the IRCR intervals. This decision to use IRCR intervals was made on the basis of analysis provided by Data Analysis Australia (DAA), which indicated that the most reliable indicator of the available capacity at peak times was the IRCR method (i.e. the median of the 12 Peak Trading Intervals for each Hot Season). The IMO notes that since it proposed a variant of the current static RD methodology, EnerNOC has presented a discussion paper to the MAC (February 2011 meeting) proposing the introduction of a dynamic baseline methodology. A copy of the discussion paper is available on the following webpage: http://www.imowa.com.au/MAC_35 Using a dynamic baseline model to measure a DSP's performance would result in increased certainty around the output of the DSP prior to being issued a Dispatch Instruction than under the current static model. However, the IMO notes that even with a dynamic baseline model and advanced DSM equipment that indicates real time

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			consumption of associated NDLs, complete certainty of the consumption of the DSP had a Dispatch Instruction not been issued would be unlikely. The IMO is interested in views during the second submission period on the issue of whether a static or dynamic baseline methodology should be adopted. The IMO presents two options for progressing this issue and wishes interested parties to submit on which of these constitutes the best pathway forward: • continue with the proposed amendments to maintain a static baseline methodology based on the 12 IRCR periods as part of RC_2010_29 (as originally proposed); or • remove the proposed amendments from RC_2010_29, with the MAC to consider the static and dynamic model options further. Should the proposed amendments to the RD methodology not progress the IMO notes that IT systems changes will still be required to amend the current RD calculation to be based on DSPs and not CLs.
Calculation of RD - dynamic vs. static baseline methodology (Issue 4)	Alinta	The method for measuring DSP performance also differs from the manner that capacity obligations apply to other Scheduled Generators because when dispatched, the additional capacity provided by those facilities will be known with certainty and those facilities are only paid for the additional capacity they actually make available to the system.	The IMO notes that the different measurement of performance between DSPs and Scheduled Generators reflects that when a: • Scheduled Generator is issued a Dispatch Instruction there is certainty as to the starting point from which to measure their performance; and • DSP is dispatched there is no certainty as to the exactly what the DSP would have been consuming during the time it is dispatched. This is similar to the case of an Intermittent Generator that is requested by System Management to reduce its output in that it is not possible to tell exactly what the Intermittent Generator would have produced had it not

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			responded to the Dispatch Instruction. DSM is an important source of capacity for managing high energy demands and the associated strain on both the transmission and distribution networks during peak periods and other events. The IMO considers that reducing the consumption of energy during peak periods directly promotes Market Objective (e). Given these associated benefits with using DSM, the IMO considers that the distinction between the methods for measuring the performance of DSM and generators with capacity obligations is warranted.
Calculation of RD - dynamic vs. static baseline methodology (Issue 4)	Alinta	The changes proposed under RC_2010_12 would allow CLs and DSPs already operating below their RD to be paid as if they had reduced consumption from their RD level. Alinta also notes that the converse case is true if operating above their RD level.	Refer to above. This situation is no different to that encountered under the current Market Rules. The IMO confirms that given that RD is a median value it is also possible that a DSP could be operating above its RD when dispatched.
Calculation of RD - dynamic vs. static baseline methodology (Issue 4)	Alinta	That the Market Rules effectively assume that a CL or DSP is operating at its RD level before a Dispatch Instruction is issued would appear to create a potential misalignment between the objective of System Management in issuing a Dispatch Instruction (to achieve a specific load reduction) and the (financial) incentive faced by the Market Participant that registered the CL or DSP (to minimise actual load reduction). As a result Alinta considers that proposed clause 4.11.3B would also lead to System Management being uncertain as to the effectiveness of issuing a Dispatch Instruction to CLs or DSPs to achieve a specific load reduction.	Refer to above.
Calculation of RD	EnerNOC	A static RD measurement is inherently an	The IMO agrees that it is unlikely that an electricity user's demand

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- dynamic vs. static baseline methodology (Issue 4)		inappropriate methodology to employ for operational purposes for a resource participating in the WEM. Almost no electricity users have demands that remain flat over the day let alone the course of a season or a year.	would remain flat over a day. However, the IMO notes that the wider issues associated with adopting a dynamic baseline model (which would account for these variations in demand) need to be further considered, and reiterates its request for submissions on the two identified pathways forward.
Calculation of RD - dynamic vs. static baseline methodology (Issue 4)	EnerNOC	The issues that the IMO seeks to resolve through modifying the RD intervals and the exclusion rules are each symptoms of the use of a flawed static baseline methodology to determine the RD measure. Moving away from a static RD would not only prevent the inherent conflicts between planning and operations, it would also improve the overall accuracy and integrity of the RD measure and associated performance calculations.	Refer to above.
Calculation of RD - dynamic vs. static baseline methodology (Issue 4)	EnerNOC	Notes the following points: • The WEM would benefit by the use of improved measurement methodologies, which both are more accurate and mitigate against gaming activities by Market Participants. • There is a clear choice to both accomplish the objectives of the IMO's proposed changes to the RD methodology and to also improve its accuracy in general: a measurement methodology known as a "profile" baseline. • Notes that EnerNOC will shortly submit a Rule Change Proposal seeking to implement an RD calculation based on a more accurate profile baseline.	Refer to above.

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		• Acknowledges the rule change process within the WEM and recognises that its proposal to consider a dynamic measure may necessitate the parallel consideration of both rule change alternatives.	
Calculation of RD - dynamic vs. static baseline methodology (Issue 4)	EnerNOC	Underlying the concept of aligning IRCR and RD intervals is an assumption that because a customer managed their IRCR in the previous year that they can be assumed in the current year to have already curtailed demand when System Management would otherwise dispatch them. EnerNOC considers this assumption is erroneous, and potentially dangerous.	Refer to above. This issue relates to the use of a static baseline methodology which is reliant on information from the previous Hot Season to indicate the likely availability of a facility. The IMO also notes that the intent of the proposed changes is to allow an end use customer to make a decision over which potential payment stream they wish to target (IRCR or DSM).
Calculation of RD - dynamic vs. static baseline methodology (Issue 4)	EnerNOC	Questions the wisdom of a rule change which will in its very design exclude the WEM's most demand-flexible and peak-responsive loads from providing capacity to the market.	The IMO disagrees as the proposed changes will simply require an associated NDL to make a decision whether to reduce its IRCR obligations or increase the RD of the DSP with which it has contracted. Any cost impacts to a DSP as a result of one of its associated NDLs targeting a reduction in its IRCR, for which the DSP provider would receive no financial benefit (only the Market Customer to which the NDL contracts energy), should be taken into account by the DSM aggregator when establishing contracts. The IMO however notes the potential benefits (and costs) associated with implementing a dynamic baseline methodology and reiterates its request for comments from interested parties of the identified pathways for proceeding with this issue. The IMO notes that further consideration of solutions to the current double payment issues will be required for methodology using non-IRCR intervals.
Calculation of RD - dynamic vs.	EnerNOC	The RD measure, were it to remain static, be amended to include an additional 20 Trading	DAA concluded that the IRCR methodology (the median of the 12 Peak Trading Intervals for the Hot Season) produces the most reliable

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static baseline methodology (Issue 4)		Intervals for a total of 32, being the peak 8 Trading Intervals on each of the peak four days in the previous Hot Season, and to utilise an arithmetic mean for averaging instead of a median.	results when it comes to predicting what the Load will likely be operating at during a peak demand event during the next year. Using a larger sample size would reintroduce the current double payment issue. For example if 32 Trading Intervals were to be used and a DSP successfully targeted the 12 IRCR intervals (thereby reducing its consumption), the remaining 20 Trading Intervals within the dataset would allow for a higher RD to be set than would otherwise be the case. Additionally, due to the small sample size (12 intervals) it is more appropriate to use a median, as an average would be distorted by any outliers.
Calculation of RD and removal of exclusions due to maintenance (Issue 4)	Energy Response	In practice the current RD measurement methodology which allows for substitutions is acceptable, however the use of IRCR intervals will only be suitable if substitutions and adjustments are allowed. The use of a small subset of data (i.e. the 12 IRCR Intervals) poses another difficulty and is not a very robust approach when dealing with the inherent variability of large commercial and industrial loads; this can cause serious problems without a substitution option. Sites do have extended shutdowns and outages. That does not mean that they are unable to provide benefit to the market in the following summer.	Given the outcomes of DAA's analysis, as noted above, the IMO disagrees with Energy Response that the use of the 12 IRCR intervals is not a very robust approach. The IMO acknowledges that where a site is on extended shutdown or outage during these 12 IRCR intervals then the calculation of the relevant DSP's RD for the next year may not reflect the DSP's availability to the capacity market. This would reduce their level of Capacity Credits and associated income stream. However, in this instance the Market Customer to which the NDL belongs has already been compensated during the previous year, as its IRCR would have been reduced while it was either on outage or extended shutdown. Additionally, the IMO considers that there is an equal random possibility that during the past year an NDL: • had shut down during the 12 IRCR intervals , resulting in a lower RD for the current year, and yet is available during peak periods in the current year; and

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			• was available during the 12 IRCR intervals, resulting in a higher RD for the current year, and yet is on an outage during the peak intervals in the current year.
Calculation of RD and removal of exclusions due to maintenance (Issue 4)	Energy Response	The variance is too large to make this a viable measurement method without the possibility of adjustments.	Refer to above.
Calculation of RD using IRCR periods (Issue 4)	Energy Response	The proposed changes will work counter to the Wholesale Market Objective of treating each technology equally. There would be a substantial cost impact on Energy Response in having to make up the difference in capacity.	The IMO disagrees that removing the current "double payments" associated with an NDL undertaking maintenance during peak periods to reduce its IRCR (as passed through by the Market Customer to which it contracts energy) and then having these periods excluded from its RD calculation would result in differences in the treatment of technology types. This is because a Market Generator does not receive an IRCR benefit where it provides (or doesn't provide) energy during peak intervals. Any cost impacts to a DSP as a result of one of its associated NDLs targeting a reduction in its IRCR, for which the IMO notes the DSP provider would receive no financial benefit (only the Market Customer to which the NDL contracts energy), should be taken into account by the DSM aggregator when establishing contracts.
Calculation of RD and removal of exclusions due to maintenance (Issue 4)	Energy Response	Under the proposed amendments, where substitutions are not allowed for the IRCR intervals, Energy Response would experience a loss of almost 8 percent of its total DSM available. This loss is not adjustable under the proposed changes and is compounded by the fact that loss factors are also not compensated, which generally account for about 6 to 10 percent, thereby making aggregated DSM	Refer to above. The IMO notes that consideration of compensation for loss factors is outside the scope of RC_2010_29.

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		disadvantaged when compared to generation by between 14 and 18 percent.	
Calculation of RD using IRCR periods (Issue 4)	EnerNOC	End-use customers choosing to secure their direct economic interest by reducing their IRCR will impact existing and future DSPs, with potential for capacity shortfalls, Supplementary Reserve Capacity (SRC) and/or the need to additional generation.	Refer to above. The IMO notes that a DSP will be able to substitute alternative NDLs into its programme and therefore mitigate against any risks it is unable to meet its capacity obligations and that an SRC event may arise.
Calculation of RD using IRCR periods (Issue 4)	Energy Response	Overall the proposed changes are likely to severely impede on the levels of Reserve Capacity to be supplied by DSM aggregators and will potentially lead to high costs for the entire WEM.	The IMO disagrees as the proposed amendments will ensure that the RD of a DSP better reflects its likely availability and consequent value of the reduced consumption offered by the DSP to the market than currently. The IMO also reiterates that the outcomes of DAA's assessment indicated that the use of the 12 IRCR intervals would produce a more stable and reliable measure of a DSP's likely availability. The Reserve Capacity Requirement (clause 4.29.1) caps the cost of capacity to the market as any additional capacity required is adjusted for in the Monthly Reserve Capacity Price using the Excess Capacity Adjustment..
Calculation of RD using IRCR periods (Issue 4)	EnerNOC	Believes that the IMO's proposed approach to DSP performance measurement is likely to create significant risks for DSM capacity provision and lead to greater instability and higher costs to the market as a whole.	Refer to above.
Calculation of RD using IRCR periods (Issue 4)	EnerNOC	By aligning the intervals used to determine a DSP's RD measure with those intervals used for IRCR purposes, the market would be bundling two separate mechanisms that require distinct measurements for their own specific purposes	A Market Customer's IRCR is equal to the share of the Reserve Capacity Requirement allocated to it based on its expected historic system peak demand plus an additional reserve margin. These are updated monthly to reflect adjustments to a Market Customer's share values. Alternatively, a DSP's RD will be reflective of a level of

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			curtailability that could be expected during those peak IRCR intervals (the basis on which capacity is charge to Market Customers). In essence the IRCR amount paid by a Market Customer acts as compensation for the availability of capacity during peak intervals (from DSPs and other generation types). Given the interrelated nature of the two mechanisms the IMO considers it is appropriate that they are more closely aligned by using same 12 peak intervals in each calculation.
Calculation of RD using IRCR periods (Issue 4)	EnerNOC	The supposed "conflict" between IRCR and RD is a consequence of an approach that has an underlying assumption that it is appropriate to employ the same methodology for determining a CL's IRCR and its ability to provide capacity to the WEM when dispatched. By continuing with the approach the IMO is conflating resource adequacy and planning activities with measurement needs in an operational context.	Refer to above.
Calculation of RD using IRCR periods (Issue 4)	EnerNOC	By linking the RD and IRCR methodologies, the IMO appears to falsely presume that a DSP would only be dispatched by System Management in response to a capacity shortfall, and not for the other likely purposes such as transmission constraints or unforeseen system contingencies.	Refer to above. The IMO disagrees that it has assumed that capacity would only be dispatched by System Management in response to a capacity shortfall. There are a number of reasons why a DSP might be dispatched (i.e. lack of sufficient generation capacity, transmission issues etc). These reasons however do not affect the merits of linking the two methodologies and will result in the removal of the current "double counting" issue.
Calculation of RD using IRCR periods (Issue 4)	EnerNOC	As a result of RC_2010_29, IRCR management and demand side participation will become mutually exclusive.	The IMO confirms that this was the intent of bundling the two mechanisms and will result in the removal of the current "double counting" issues.

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Calculation of RD using IRCR periods (Issue 4)	EnerNOC	End-use customers choosing to provide DSM for capacity purposes to the detriment of reducing their peak loads will lead to capacity forecasts being higher than would otherwise be necessary, increasing electricity costs to all customers in the SWIS.	The proposed amendments will allow an end-use customer to either reduce its IRCR or increase the RD of any DSP it is associated with. The IMO agrees that if an end use customer aims to increase its RD this will potentially lead to increased capacity forecasts. The IMO however disagrees that this cost will necessarily be borne by all customers but rather would be allocated to the specific NDL adjusting its behaviour. To illustrate this impact consider a 1 MW increase in an NDLs consumption[3]. This would lead to a: • increase in the capacity forecasts • CC benefit to the NDL (1 MW of CCs) • IRCR cost to the NDL, based on the TDL_Ratio (approx. 1.4 x the cost of a Capacity Credit) Under this example if a NDLs IRCR is not reduced it will effectively pay for the increase in the Reserve Capacity Requirements (forecast).
Calculation of RD using IRCR periods (Issue 4)	EnerNOC	While perhaps unintentional, adopting RC_2010_29 would signal that the market is seeking to either remove an incentive to reduce peak demands or limit the quantity of DSM providing capacity in the WEM. Either signal is likely to lead to market inefficiencies and work against Wholesale Market Objectives (a), (d) and (e).	Refer to above. The IMO notes the dual incentive of reducing peak demand and increasing the supply of DSM capacity in the WEM is currently inefficient as it creates a double payment stream. The intent of the proposed changes is to allow an end use customer to make a decision over which payment stream they wish to target.
Calculation of RD	EnerNOC	The proposed RD measurement approach penalises	The IMO disagrees, noting that while IRCR management would reduce

[3] Note that this example assumes that the NDL is operating directly in the SWIS and so is not subject to any contracting arrangements with either a Market Customer (to pass through IRCR costs) or DSP (thereby accruing full CC benefits associated with an increase in its RD).

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using IRCR periods (Issue 4)		customers for IRCR management even when those activities are non-coincident with the likely dispatch requirements of a DSP by System Management.	the DSP's RD level in the following year, the NDL would have already been compensated through their IRCR reduction.
Calculation of RD using IRCR periods (Issue 4)	EnerNOC	In its attempts to limit "double payment" concerns, the IMO has advocated for an RD methodology that unfairly penalises customers that manage their IRCR exposure as it will end up removing all WEM derived payments for any load reductions dispatched by System Management, whether or not they are actually coincident with IRCR intervals. While this risk is also present in the current RD methodology, it is guaranteed under RC_2010_29.	Refer to above.
Calculation of RD using IRCR periods (Issue 4)	EnerNOC	The alignment of both RD and IRCR measures would produce an outcome where the loads most capable of assisting the WEM as CLs would have no incentive to provide this capacity.	Refer to above. The intent of the proposed changes is to allow an end use customer to make a decision over which potential payment stream they wish to target (IRCR or RD).
Commencement of proposed RD methodology (Issue 4)	EnerNOC	If the IMO were to proceed with its proposed RD methodology, any changes should be scheduled for implementation and used no earlier than the 2012/13 Capacity Year.	As noted above the IMO will be seeking the views of interested parties on the pathway forward regarding the consideration of a static vs. a dynamic baseline methodology. Further consideration of the implementation of any potential Amending Rules will be dependent on the views of interested parties during the second submission period.

Request for Second Round Submissions

The second submission period for RC_2010_29 will close at 5pm on **Friday 15 April 2011**.

The IMO requests the views of interested parties during the second submission period on the issue of whether a static or dynamic baseline RD methodology should be adopted. To progress this issue the IMO identified two options and requests submissions on which of these constitutes the best pathway forward:

- continuing with the proposed amendments to maintain a static baseline methodology based on the 12 IRCR periods as part of RC_2010_29 (as originally proposed); or

- removing the proposed amendments to the baseline methodology from RC_2010_29, with the MAC to consider the static and dynamic model options further.

Additionally, the IMO requests interested parties to take into consideration the discussion and outcomes of the public workshop when making their submissions during the second submission period for RC_2010_29.

Wholesale Electricity Market
Pre Rule Change Discussion Paper (PRC_2011_01): Profile Methodology for the Relevant Demand calculation

Change requested by:

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Date submitted:	31 January 2011
Urgency:	3-high
Change Proposal title:	Profile Methodology for the Relevant Demand calculation
Market Rule(s) affected:	4.26.2C

Introduction

Market Rule 2.5.1 of the Wholesale Electricity Market Rules provides that any person (including the IMO) may make a Rule Change Proposal by completing a Rule Change Proposal Form that must be submitted to the Independent Market Operator.

This Change Proposal can be posted, faxed or emailed to:

Independent Market Operator
Attn: Manager Market Development and System Capacity
PO Box 7096
Cloisters Square, Perth, WA 6850
Fax: (08) 9254 4339
Email: market.development@imowa.com.au

The Independent Market Operator will assess the proposal and, within 5 Business Days of receiving this Rule Change Proposal form, will notify you whether the Rule Change Proposal will be further progressed.

In order for the proposal to be progressed, all fields below must be completed and the change proposal must explain how it will enable the Market Rules to better contribute to the achievement of the wholesale electricity market objectives. 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.

Details of the proposed Market Rule Change

1. Describe the concern with the existing Market Rules that is to be addressed by the proposed Market Rule change:

Background:

The current calculation methodology used for the Relevant Demand (RD) measure, described in 4.26.2C, as well as the methodology proposed by the IMO in its Rule Change Proposal: Curtailable Loads and Demand Side Programmes (RC_2010_29), employs an inaccurate static baseline measurement that risks overstating the actual amount of Demand Side Management (DSM) capacity in the Wholesale Electricity Market (WEM). The resulting inaccurate measurements can have significant implications in terms of reliability and system planning, as well as potentially inflating the overall cost of capacity in the market. Moreover, the static baseline measurement used (and proposed) as the RD level, also increases the likelihood of gaming and potentially creates conflicts for large commercial and industrial customers who seek to manage their Individual Reserve Capacity Requirement (IRCR) exposure.

As mentioned in EnerNOC's submission to RC_2010_29, EnerNOC believes that the IMO, Market Participants, and WA electricity users, would all benefit from a more accurate profile-type baseline methodology. While static measures like the IRCR calculation are appropriate for system planning purposes that must occur well in advance, their inability to account for changing load conditions makes them unsuitable for measuring capacity resources participating in a market such as the WEM. Conversely, profile baselines constantly update to reflect changes in consumption and are able to provide an accurate measure of DSM capacity and are specifically designed for use in an operational context. Such baselines have received support in numerous third party studies and are employed in electricity markets and utility-operated DSM programmes throughout the world.

This discussion paper will seek to outline the inaccuracies inherent in static baseline measurements and the resulting concerns that can (and likely do) negatively impact the WEM and the Wholesale Market Objectives. Rather than preserving this underlying inaccuracy or seek to mitigate some of the negative effects of it – as RC_2010_29 proposes – EnerNOC believes a better and more effective solution is to begin the process of moving towards a profile methodology for the calculation of the RD for DSM beginning in the 2012/2013 Capacity Year.

Static vs. Profile Baselines:

To understand the benefits of changing the RD measure from a static baseline to a profile calculation, it is first necessary to identify the problems that result from the use of a static measurement methodology.

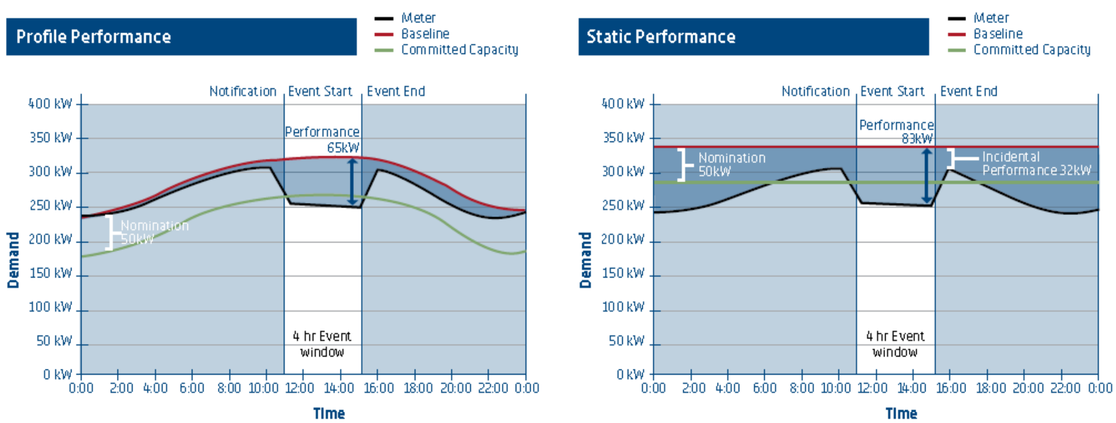
The current calculation of RD and the proposed change under RC_2010_29 are both considered to be static methodologies since they use a single, fixed value as a forecast for CL or DSP loads for the following Capacity Year. By essentially predicting electricity consumption to be the same regardless of the time of day, day of the week, or season of the year, and based upon a consumption pattern that is 12 months in the past, such an approach is unable to accurately predict a given customer's (or DSP's) load at a given time. It can therefore not accurately measure the demand reduction that actually occurred when DSM is dispatched by System Management. Almost no electricity users have demands that remain flat over a day, let alone the course of a season or year. For example, in addition to fluctuating usage throughout the day, in the period since a CL's RD was calculated, a customer may have installed new equipment that has drastically increased or decreased their load profile. Consequently, a static RD simply cannot provide insight into whether or not a CL/DSP has load reduction capabilities at the specific time SM needs them, nor can it be counted on to provide an accurate assessment of CL/DSP performance after a dispatch.

With the current and proposed RD based on demand during system peak periods, the RD is likely to result in "incidental performance", where a customer is already operating below their baseline and receives credit for greater levels of demand reductions than what actually took place. The IMO has recognised this inaccuracy, acknowledging that an "aggregated DSP (may) already be operating at below its RD level when dispatched and may not be required to curtail consumption at all to meet the Dispatch Instruction"[1].

This incidental performance can have serious implications. As the IMO has also identified, the inaccuracy could impact system reliability by overestimating the amount of available capacity, leading to System Management potentially allowing more outages than should be permitted to maintain reliability standards.

EnerNOC believes there is a clear choice to both accomplish the objectives of the IMO's proposed changes to the RD methodology under RC_2010_29 and to also improve its accuracy in general: a measurement methodology known as a "profile" baseline. Profile baselines, which closely resemble a site's actual load profile throughout the day and are based on historical interval meter data over a recent period prior to dispatch, stand in stark contrast to static baselines such as the current RD methodology. Profile baselines are also often referred to as "dynamic" as they are changed and updated to reflect recent conditions and consumption patterns. To compare the two baseline types of static and profile, an example has been shown in the figure below which assumes a customer has registered demand side capacity of 50kW.

Figure 1: Profile vs Static Baselines



Using a static baseline (right graph), the forecast baseline is far greater than the actual load throughout the entire day. Peak performance during dispatch is measured at 83kW, well above the expected 50kW.

Applying an accurate profile baseline generates closer alignment with actual consumption patterns. By having a baseline that follows actual metered demand before and after dispatch, performance is measured at 65kW, or more than 20% below the static baseline.

In the example shown, a static baseline provides 32kW of incidental performance, or nearly 40% of the recorded performance. This incidental capacity represents significant program costs for the WEM, with DSM comprising around 8% of the WEM's capacity. With over 450MW of DSM credited for 2012/13, were incidental performance levels of 20% or more being experienced this would indicate a potential capacity shortfall (or overpayment) of 100MW or more. This represents in excess of $15 million in 12/13 in unnecessary capacity costs and payments.

[1] Agenda Item 8a: Curtailable Loads - Relevant Demand Analysis, MAC Meeting No 30: 11 August 2010, pg1

Profile Baseline Considerations:

Across international markets that engage DSM, the most widely used profile calculations employ what is known as a High X of Y method to select the historical interval data that is used. Examples include the PJM Interconnection, the world's largest electric grid which covers the mid-Atlantic region of the United States; the Ontario Power Authority / Independent Electricity System Operator (IESO) in Canada; DR programs with utilities in the US states of California, Arizona, Florida, Idaho, and including the world's largest utility DR program run by the government utility / US federal agency the Tennessee Valley Authority. A High X of Y baseline takes the Y most recent days preceding a dispatch of DSM (also called an "event") and uses the data from the X days with the highest load within those Y days. High X in Y profile baselines have a few different components to them, as described below. There are various iterations of these components, but over recent years, best practices have begun to emerge – both as the result of experience and third party studies.

Profile calculations utilise the following components:

- Look-back Window – Because profile baselines are designed to change over time to reflect actual load conditions, they use consumption data from a recent period – the look-back window - prior to a dispatch (or test) to calculate the Relevant Demand. The look-back window determines the range of days prior to a dispatch of a DSM resource that should be considered in the baseline. In other words, the look back window is the value of Y in the High X of Y context. The length of the look back window is an important value in the baseline equation and must take into account a number of factors. First, a baseline that only considers very recent data may place an undue emphasis on short-term variations in load and might not accurately capture true demand reductions. Second, given sufficient or excessive warning and incentive to do so, a site could actively and intentionally increase consumption prior to a dispatch in order to maximise its baseline and thus overstate actual curtailment levels. A longer baseline window acts to prevent gaming such that the cost of active manipulation to elevate baseline levels outweighs the benefit as the customer's supply bills would quickly rise due to increased consumption and potentially higher demand charges – to game a baseline with a well-chosen Y value would therefore require increased consumption over the course of many days when the customer believes a dispatch is likely, an expensive proposition. In light of these issues, many other energy markets and programs such as the OPA/IESO and utility programs listed above, have accepted that a period of 10 (non-dispatch event) business days reasonably represents consumption for normal operations and therefore makes up a preferred baseline window for these markets and programs where DSM is primarily providing a capacity or reliability resource (as compared to ancillary services). Using a 10 day time window provides an appropriate balance of time for these markets, being short enough to account for near-term trends and long enough to limit opportunities for manipulation.
- Exclusion rules – Exclusion rules determine what data (X) can be included in the look-back window and are designed to ensure that the baseline is only utilising interval data that will lead to an accurate forecast of load during the time of a likely dispatch. Days outside of the availability window of the DSM resource – in the case of the WEM, weekends and public holidays– are excluded so as not to impact the baseline measure and its accuracy. These rules also usually exclude any days where the DSM resource was dispatched, since the load profile on such days is atypical and not indicative of normal operating conditions. Exclusion rules also ensure that data is used only from the hours when DSM can be dispatched – in the WEM, this is noon to 8pm, unless a CL/DSP has made themselves available outside of that range.
- Relationship between X and Y – Once a group of prior days is identified as the Y days, that group of days is narrowed down to a subset of X days in order to obtain a better representative group of data for use in the baseline calculation. When selecting X it is

important to consider the likely conditions in which DSM is likely to be dispatched. For example, for DSM that is called primarily for use during peak periods like in the WEM, dispatch is very much linked to weather conditions, which are a central determinant of electrical consumption. As such, the RD methodology used in the WEM must be explicitly designed to appropriately forecast electricity usage during extreme weather events. If all days from in the look-back window were used, data from days with less extreme weather conditions (and therefore less demand) would be used, which will consistently understate the baseline measure and its accuracy. To combat this understatement, best practice-based DSM programs use data only from select days with the highest loads from within the look-back window. A 'High 3 of 10' and 'High 5 of 10' are among the most common iterations, with the latter approach considered more amendable to addressing the issue of understated performance while incorporating 2 more days of load data, reducing volatility.

With these baseline parameters in mind, consider the following High 5 in 10 baseline example, as illustrated in Table 1. The baseline for each time interval, is determined by averaging the load on those five days for each hour. In this example, the top High 5 Days are 2, 4, 6, 7, and 9.

Table 1: High 5 of 10 Data

Day	Interval 1 (kW)	Interval 2 (kW)	Interval N (kW)	Average usage (kW)
1	2,000	2,100	2,000	2,033
2	2,100	2,200	2,100	2,133
3	2,000	2,100	2,000	2,033
4	2,200	2,500	2,200	2,300
5	2,000	2,100	2,000	2,033
6	2,100	2,200	2,100	2,133
7	2,400	2,300	2,400	2,367
8	2,000	2,100	2,000	2,033
9	2,600	2,700	2,600	2,633
10	2,000	2,100	2,000	2,033
Baseline	**2,280**	**2,380**	**2,280**	

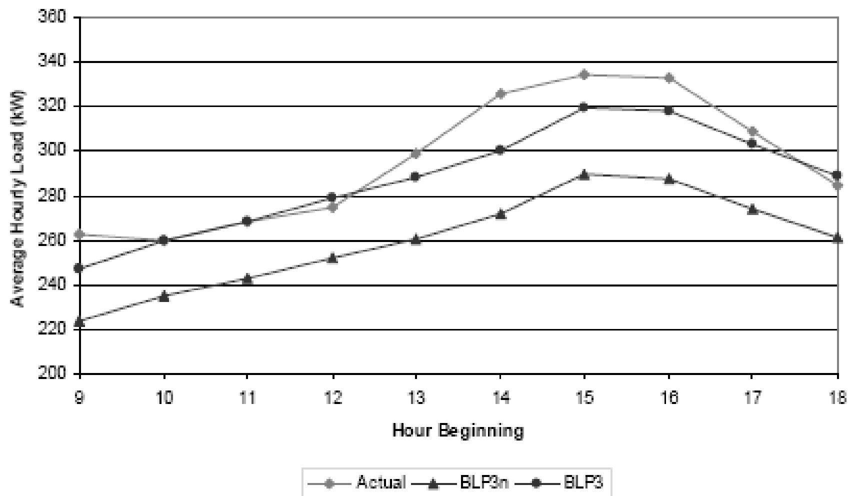
- Day of Adjustment – Since conditions on the day of a dispatch can be markedly different from what may have occurred during the look-back window, an adjustment is often applied to reconcile any deviations in usage between the baseline and the actual meter data. This is especially important in the WEM where DSM capacity is most likely to be dispatched during the peak periods of the Hot Season. Because X in Y baselines of the inevitably exhibit some downward bias – even ones that use the top 3 or 5 demand days out of the last 10 – it is important that the RD method can account for the higher-than usual consumption patterns that will be seen on days with such extreme weather. These day-of adjustments don't change the shape, or profile, of the baseline – rather, they simply transpose it along the y-axis to ensure accuracy by aligning it with actual load conditions on the day of a dispatch. While a final step in the profile baseline calculation, they are crucial to an accurate output. In a recent study[2] of baseline calculations by the Lawrence Berkeley National Laboratory (LBNL) based in California, the report authors concluded that "*applying a morning adjustment factor significantly reduces the bias and improves the accuracy of all baseline load profiles examined in our sample.*" Similar studies by the international energy consultancy KEMA[3], as

[2] Lawrence Berkeley National Laboratory, "Estimating Demand Response Load Impacts: Evaluation of Baseline Load Models for Non-Residential Buildings in California", January 2008, page 25
[3] KEMA – XENERGY, "Protocol Development for Demand Response Calculation- Findings and Recommendations", February 2003, p. 2-12.

well as the AEIC Load Research Committee[4], support the conclusion of the LBNL study that the use of a day of dispatch adjustment improves accuracy and reduces bias. EnerNOC's own internal data analysis, presented to the Association of Energy Services Professionals (AESP) in November 2010, provides further support for these conclusions and found that unadjusted baselines understate load.[5]

Consider the following example from the aforementioned LBNL study. Figure 2 below shows a comparison of actual meter data to an unadjusted 3 in 10 profile baseline (labelled BLP3n) and a 3 in 10 profile baseline with a day-of adjustment applied (labelled BLP3). While the unadjusted baseline clearly understates the actual metered load, once an adjustment is applied, the baseline comes very close to forecasting the actual load.

Figure 2: Unadjusted vs Adjusted 3 in 10 (LBNL)



One of the most crucial aspects of a day-of-adjustment is when it is applied – either at the time of dispatch, or at the beginning of the dispatch event (which can be hours later). To limit gaming and properly reward curtailment actions it is crucial that this adjustment is applied at the time of dispatch (or test). An adjustment applied at the event start time can result in an overstated baseline for a customer who is engaged in legitimate pre-curtailment activity, such as pre-cooling so that HVAC load can be curtailed during the event period. Equally important, adjustments applied post-dispatch at the event start time also invite the opportunity for customers to game the baseline by increasing load post-dispatch to raise the baseline higher than it would have otherwise been. For these reasons, EnerNOC recommends that day of adjustments should be applied at the time System Management dispatches DSM in order to ensure the integrity of the RD measure – an approach validated by third party studies as a way to combat the potential for gaming.[6]

It is also important to consider whether adjustments reflect demand conditions symmetrically (baseline adjusted up and down) or asymmetrically (baseline only adjusted up).The symmetric approach considers that day-of conditions can have a real impact on customer demand in both directions and therefore symmetric adjustments maximise the accuracy of a baseline calculation. However, they also permit downward adjustments that represent serious causes for concern. The reduction of a customer baseline based on day-of conditions can

[4] AEIC Load Research Committee. Estimation Errors in Demand Response with Large Customers. November 2009.
[5] Analysis of Baseline Methodologies and "Best Practice" Recommendations, EnerNOC Inc, Presented to AESP on 9 November 2010
[6] Working Group 2 Demand Response Program Evaluation – Program Year 2004 Final Report. Prepared for the Working Group 2 Measurement and Evaluation Committee, by Quantum Consulting Inc. and Summit Blue Consulting, LLC, 2004.

have damaging, unintended consequences. Symmetric adjustments are appropriate for programs in which events are less likely to occur on days of extreme load conditions. For example, in programs where dispatch may occur in Spring and Autumn, the event day may not be expected to have a significantly different load from previous days. Therefore there is an equal chance that an unadjusted baseline could be lower or higher than actual load prior to an event, in which case a symmetric adjustment would be appropriate. For all other programs however, asymmetric adjustments have been considered more appropriate given that they properly align incentives of participants with objectives of demand response programs. In their studies, both LBNL and KEMA recognised that a symmetric adjustment could penalise a customer if the adjustment window overlapped with pre-cooling or early curtailment actions. In this case, the meter readings would be below normal and the adjustment would shift the baseline downward too much. This would result in a smaller curtailment measurement that underestimated actual performance.

Symmetric baseline adjustments are of particular concern when coupled with lengthy periods of advanced notification, as is the case in the WEM (up to 4 hours). Under the Market Rules, dispatches from System Management could be received as early as 8:00am, a time at which some participating sites may not be fully operational. As day of adjustments are applied at the time sites are notified of an impending dispatch to avoid potential gaming, the adjustment would need to be applied at that early time, even though at such an hour consumption patterns are almost guaranteed to be a poor projection of consumption patterns later in the day. Consider the example of DSM dispatch to address a spike in demand due to extreme weather conditions in the afternoon – ambient temperatures, and the resulting HVAC loads, may not even be above average at 8:00 in the morning.

It is also worth recognising that adjustments can be done on an additive (kW) or a scalar (%) basis. The scalar technique is based on a percentage comparison. If load on an event day prior to notification is measured to be 30% above the calculated baseline, then each time interval of the baseline would be the product of the calculated baseline and 130%. The additive approach instead calculates the actual demand difference in kW. If load during the calculation period is 50 kW above the calculated baseline, then 50 kW is added to each interval in the actual event baseline. While this may not result in a mathematical difference at the first interval, it can lead to minor differences in measurements over the course of the dispatch event. LBNL found that either method greatly increases the accuracy of profile baselines, whereas KEMA, voiced greater support for an additive approach. EnerNOC is proposing an additive adjustment in this rule change proposal.

Because day-of-adjustments are so crucial to the accuracy of a baseline, any use of the Relevant Demand level to test DSM capacity availability (as proposed in RC_2010_29) in lieu of a dispatch from System Management must incorporate a methodology to allow for the inclusion of this integral baseline component.

<u>Alternative Profile Methodologies for DSM Measurement</u>

There are alternative methods of selecting data for the look-back window, namely rolling averages and regressions. Our experience indicates that a rolling average baseline is used by exclusively by ISO-NE, a System Operator of a 32 GW market in the Northeast US. This method uses historical meter data from many days, but gives greater weight to the most recent days, and is more complex than the typical High X of Y method. Another alternative is the regression method, which uses a regression analysis to estimate load based on prior load behaviour, weather conditions, calendar data, system demand, and time of day. Used in the Texas market of ERCOT, regression analysis is believed to be the most accurate of baseline methodologies because it takes into consideration more variables that influence load. However, regression baselines come with significant downsides, which outweigh their potential for improved accuracy. They are complex to calculate and require load, weather, and day type data. They may rely on interval meter data from an entire summer to estimate load during event days of that summer. In this case, it is not possible to calculate a baseline during a dispatch, since the regression equation can only be created at the end of the summer. In EnerNOC's view, it is vital to chart the baseline during a dispatch because it can show if a customer is or is not meeting curtailment expectations. Therefore, because regression baselines require more types of input data and because they cannot be used to generate baselines during an event, EnerNOC believes they are not a preferred profile method.

A comparison of the baseline types available and discussed in this section is outlined in the table below.

Table 2: Baseline Comparison

Baseline Type	Operational Alignment	Load / Weather Sensitivity Addressed	Visible to CL during dispatch	Potential for Gaming
Static	Low. Better suited for system planning.	Low. RD measure does not change.	Yes. Known months in advance.	High. CL can be offline or below baseline without taking action.
High X of Y	High. Follows load profile; shows real-time capability	High. Uses comparable days and applies an adjustment factor	Yes. Systems can easily calculate in real-time.	Low. Look-back window and adjustments applied at dispatch prevent gaming.
Rolling Average	High. Follows load profile; shows real-time capability	Medium. Only applies and adjustment factor.	Yes. Systems can easily calculate in real-time.	Low. Look-back window and adjustments applied at dispatch prevent gaming.
Regression	High. Follows load profile; shows real-time capability	High. Incorporates weather, load, and comparable day data.	No. Requires data that is not available until at the end of the season.	Low. CL would need to significantly increase usage throughout the season.

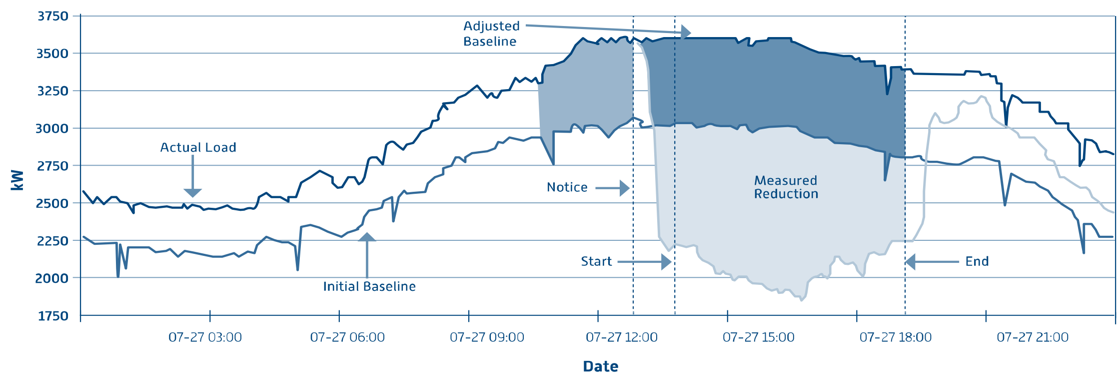
Proposed Methodology:

In light of the possible permutations identified in this paper, EnerNOC proposes **replacing the current RD calculation with a High 5 in 10 individual profile baseline, with an asymmetric day-of adjustment**. As is described below, this particular version of a profile baseline best aligns with the dispatch parameters and use of DSM in the WEM.

Our proposed baseline methodology addresses the concerns with inaccuracy inherent in the current RD methodology, and avoids the negative consequences of the RD-setting interval changes outlined in RC_2010_29 that have been outlined in our submission to that rule change. Moreover, our proposed approach seeks to improve the accuracy of DSM capacity and performance measurement, ensuring system stability and cost-efficiency.

A graphical representation of EnerNOC's proposed RD measure can be seen below.

Figure 2: Proposed Profile Baseline Method for RD Measure



The components of the proposed profile baseline method for RD include:

- **Look-back window.** A baseline needs to incorporate enough information to avoid bias from one or two data points. Consideration of the last 10 non-event, business days allows a robust number of days to be considered without going too far in the past in which load behaviour is different than current load behaviour. Use of only the top 5 days allows some of the lower usage days to be excluded, bringing the baseline closer to typically higher expected load on non-event days.
- **Asymmetric Adjustment applied at time of dispatch.** To ensure baseline integrity, EnerNOC is proposing that the baseline adjustment be applied at the time of dispatch, and consider the usage from the preceding two hours. As DSM capacity is most likely to be dispatched during the peak periods of the Hot Season, it is important that the RD method primarily seek to forecast likely usage patterns on those days – because an X in Y baseline type already exhibits some downward bias, we believe the likelihood of CL or DSP operation at below baseline levels is extremely low during these periods of dispatch in WA. In addition, the length of advanced notice for DSM dispatch in the WEM would make the application of a symmetric adjustment worrisome, as outlined previously. Since adjustments are crucial to baseline accuracy, and that a symmetric adjustment would be highly problematic because of the four-hour advanced notice in the WEM, EnerNOC is proposing an asymmetric adjustment calculated on an additive basis.
- **Individual Measurements**. When employing a dynamic baseline, it becomes more important to consider how the baseline is applied to the loads that comprise the DSP. Consider Figure 3 below – using the High Days for the aggregate portfolio of sites, Days 1, 2, 4, 5, and 8 would be used. While Participant 1's High 5 days match 80% to the portfolio, only 60% of Participant 2's do, and only a third of Participant 3's High days align.

Figure 3: Impact of Aggregation on Baseline Accuracy: Individual and Aggregate 5-in-10 Peak Load (kW)

	Participant 1	Participant 2	Participant 3	Aggregate Load
Day 1	200	65	100	365
Day 2	200	65	80	345
Day 3	200	65	70	335
Day 4	200	130	80	410
Day 5	200	130	60	390
Day 6	0	130	80	210
Day 7	0	130	110	240
Day 8	150	130	100	380
Day 9	150	65	125	340
Day 10	150	65	100	315
5-in-10, Individual	*200*	*130*	*107*	*378*
5-in-10, Aggregate	*190*	*104*	*84*	*378*

The top five loads are highlighted in blue for each participant and for the aggregate load. The average of the highlighted loads in each column is shown under *5-in-10, Individual*. The average of each participant's loads on the five peak days for the aggregate load is shown under *5-in-10, Aggregate*.

This is not just a theoretical issue. In looking at actual EnerNOC data from a March 2008 demand response dispatch employing an aggregated "High 3 of 10" method in California, less than 10% of customers had their highest three demand days aligned with those of the portfolio. In other words, over 90% of participants were not only unable to calculate their own baseline based on internal demand data, but also reliant on random (from the participants' perspective) information to understand their official performance. Also, for 16% of the participants, the "High 3" days used to calculate their baseline included none of their top demand days for the period, highlighting the inaccuracy of this approach from an individual customer perspective. Under such applications of the portfolio methodology, participating customers can understandably feel that the performance measurement process is not transparent.

Our advocacy for profile baselines to be applied at an individual level does not alter our view on the importance of performance being assessed on a portfolio basis, as the IMO has proposed in RC_2010_29, and which EnerNOC wholeheartedly supports. *Portfolio-based performance assessment is not at all mutually exclusive with individual baselines.* Performance is assessed for each comprising load in a DSP, and then summed together for the final figure of load curtailment that is delivered to the WEM. This allows for a DSP to manage its portfolio of sites and to ensure that the DSP as a whole can meet contractual obligations to the IMO by balancing out any underperforming sites with those that over perform. In fact, it can be argued that individual baselines are the best foundation for measuring aggregate portfolio performance, as they lead to the most accurate assessment of how much load an individual site actually provided during a dispatch.

Methodology Calculations

The step by step calculations required to support the profile baseline methodology proposed is outlined below to facilitate understanding:.

Baseline Variables
b = baseline average
d = non-event day
dn = nth highest energy usage day among previous 10 non-event days
t = time interval
c = highest kW energy consumption for a given time interval (t)
Adjustment Factor Variables
a = day-of adjustment
t-n = time interval starting n hours prior to event notification
Performance Calculation Variables
p = total performance
e = total time intervals during event

1. For a given time interval [t] (e.g. 30 minute Trading Interval), initial baseline [b] is calculated as the average interval demand among the 5 highest energy usage days out of the prior 10 non-dispatch days (this calculation is performed for each interval during the DR event, for example for each five minute window):

$$b_t = (c_{td1} + c_{td2} + c_{td3} + c_{td4} + c_{td5}) * 1/5$$

2. Adjustment factor [a] is calculated as the difference in observed demand and estimated baseline for a calibration period starting two hours before dispatch notification, with a minimum adjustment of 0:

$$a_t = \max\{[(c_{t-1} - b_{t-1}) + (c_{t-2} - b_{t-2})] * 1/2, 0\}$$

3. Total performance [p] is measured as the integrated difference between the sum of the baseline [b] and adjustment factor [a] less consumption [c] for each interval [t] over an event period beginning at time [0] and ending at time [e]:

$$p = \sum_{i=0}^{e} (b_i + a) - c_i$$

2. Explain the reason for the degree of urgency:

While the inaccuracies inherent in a static baseline methodology on their own justify the need for an improved RD measure, the urgent need to update the Relevant Demand calculation is driven by the IMO's proposed change to the measurement of CL performance in RC_2010_29.

By aligning the intervals used to determine a DSP's capacity capability, the RD measure, with those intervals used for IRCR purposes (as proposed under RC_2010_29), the market would be bundling two separate incentives and mechanisms that require distinct measurements for their own specific purposes. Moreover, by linking the RD to the IRCR methodology, the IMO appears to falsely presume that a DSP would only be dispatched by System Management (SM) in response to a capacity shortfall, and not for other likely purposes such as, transmission constraints, or unforeseen system contingencies. As a result, IRCR management and demand side participation in the Reserve Capacity Mechanism are likely to become mutually exclusive as successful attempts to reduce one's IRCR exposure will reduce the capacity available to the WEM.

While RC_2010_29 makes the need for the move to a more accurate profile RD methodology more urgent, the current RD methodology is itself sufficient cause for the profile RD measurement proposed here since the current static RD measure risks capacity overestimation in the WEM, and as a consequence, higher funding and operational costs for all Market Participants and end-users than may otherwise be necessary.

3. Provide any proposed specific changes to particular Rules: (for clarity, please use the current wording of the Rules and place a ~~strikethrough~~ where words are deleted and <u>underline</u> words added)

4.26.2C. ~~The IMO must:~~

~~(a) Identify the eight consecutive Trading Intervals with the highest aggregate system demand in each month during the preceding Hot Season;~~

~~(b) Subject to clause 4.26.2C(c), set the Relevant Demand (in MW) for the Curtailable Load equal to the median of the metered consumption during the 32 Trading Intervals identified in clause 4.26.2C(a), where the Relevant Demand is a positive number.~~

~~(c) Where the metered consumption during the 32 Trading Intervals identified in clause 4.26.2C(b) is not available the IMO must set the Relevant Demand based on:~~

~~i. Available Meter Data, or~~

~~ii. Load information provided by the Rule Participant, or~~

~~iii. Other relevant information.~~

~~(d) Where evidence is provided by the Market Customer that the Curtailable Load was operating at below capacity due to its consumption being reduced at the request of System Management or because of maintenance during one or more of the 32 Trading Intervals, the IMO must set the Relevant Demand based on the IMO's estimate of the Curtailable Load consumption during those intervals.~~

(a) <u>The Relevant Demand for a Curtailable Load must be calculated by the IMO for each Curtailable Load using the methodology described in clauses 4.26.2C(b)-(d).;In the case of a Demand Side Programme, the Relevant Demand for the Demand Side Programme as a whole will be equal to the sum of the Relevant Demand for each Curtailable Load comprising the Demand Side Programme.</u>

(b) <u>The Relevant Demand for each Curtailable Load for each Trading Interval during the hours the Curtailable Load or Demand Side Programme has made itself available – which must include the period specified in 4.10.1 (f) – shall be determined, subject to clause 4.26.2C(c), as the arithmetic mean of the measured demand, in kW, during such Trading Intervals in each of the Curtailable Loads' five Highest Energy Usage Days of the immediate past ten Trading Days, as defined in 4.26.2.C(c);</u>

(c) <u>The five Highest Energy Usage Days for a given Curtailable Load are those days having the highest average energy usage (in kWh) between the applicable hours of availability, as described in 4.26.2C(b). The past ten Trading Days shall exclude any day when Demand Side Management was dispatched by System Management, and shall only include Business Days.</u>

(d) <u>A Day-of Load Adjustment will be applied for each Curtailable Load for each Trading Interval in a calendar day when Demand Side Management is issued a Dispatch Instruction by</u>

System Management, which shall be equal to the average difference (in kW) between calculated Relevant Demand and the Curtailable Load's actual energy usage during the two hour period ending with the Trading Interval immediately preceding the Trading Interval for which the Dispatch Instruction was issued by System Management.

(e) If the Day-of-Load adjustment calculated under clause 4.26.2(C)(d) would result in a decrease of the Curtailable Load's Relevant Demand, then the Day-of- Load adjustment quantity will be set by the IMO equal to zero.

Glossary

Highest Energy Usage Days: Has the meaning given in clause 4.26.2C (c) and determines which days of energy usage will be used to calculate the Relevant Demand of a CL/DSP

Day-of-Load Adjustment: refers to the adjustment made to the Relevant Demand measure in response to a dispatch from System Management and has the meaning given in clause 4.26.2C(d).

4. Describe how the proposed Market Rule change would allow the Market Rules to better address the Wholesale Market Objectives:

This proposed Market Rules change would allow the Market Rules to better address all Wholesale Market Objectives, as described below.

Impact	Market Objectives
Allow the Market Rules to better address the objective	a, c, d, e
Consistent with objective	b
Inconsistent with objective	

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

The proposed changes will enable significantly greater accuracy around DSM capabilities and provision, enabling improved efficiency and reliability in the use of DSM as a capacity service within the WEM

(b) to encourage competition among generators and retailers in the South West interconnected system, including by facilitating efficient entry of new competitors;

This proposed rule will ensure that DSM remains an attractive opportunity within the SWIS encouraging new entrants interested in providing clean, DSM capacity to the WEM. Further, it will look to remove "opportunistic" DSM contributions (i.e. incidental performances), enabling competition to be undertaken on a consistent basis, encouraging ongoing innovation and avoiding the potential for extremely short-term ("fly-by-night") competitive inputs that are likely to discourage innovation and breed "conservative" applications of DSM program management;

(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;

The proposed rules provide for a Relevant Demand methodology that will enable DSM to be considered as an effective and reliable capacity service, engendering greater utilisation by SM and removing current perceptions of DSM as being less than the functional equivalent of traditional generation sources.

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

As outlined in the discussion paper previously, the proposed rule changes enable much greater accuracy in determining DSM capabilities, avoiding the potential for significant "incidental performance" scenarios inherent in the existing RD measurement approach which are likely to cost customers millions of dollars on an annual basis.

(e) to encourage the taking of measures to manage the amount of electricity used and when it is used.

The proposed rules ensure end-use customers remain able to manage their peak consumption levels as well as contribute DSM (particularly when this is not coincident with peak SWIS demand), while mitigating any attempt to game the measurement approaches for both DSM and capacity charges to achieve excessive economic returns. By enabling both opportunities to be pursued, the proposed rules seek to maximise the system-wide benefit able to be obtained through high utilisation of dynamic, flexible loads.

5. Provide any identifiable costs and benefits of the change:

EnerNOC believes that there will be a limited one time cost for the IMO to ready itself to measure DSM performance under this methodology and settle accordingly. We believe it is important to weigh these costs against the savings the profile baseline will provide. Consider the possibility that the use of a more accurate profile baseline reduces measured DSM capacity by 10% by eliminating "incidental performance". With 454.5 MW of DSM capacity in the WEM in 2012/13, that would alone represent capacity savings of $8,453,747 in the first year of operation. EnerNOC does not estimate that IMO system changes and any additional costs associated with the proposed changes would equate to, at their maximum, more than 10-20% of this estimated benefit.

In addition to the benefit identified above, by removing the incidental performance potential inherent in existing static measurements of RD, further market benefits that could accrue from the proposed rule changes including the avoidance of potential Supplementary Reserve requirements and impacts on system reliability through overestimating the amount of available capacity.

Synergy's out of session comments on PRC_2011_01

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Submission

Synergy would like to make the following comments on PRC_2011_01 as presented to the Market Advisory Committee (**MAC**) meeting number 35 on 9 February 2011.

Synergy raised concerns at the MAC that this Pre-Rule Change (**PRC**), if progressed at this stage, would result in other outcomes not identified in the presented paper. Synergy is concerned that the MAC has not properly considered all the implications of this proposal and before allowing it to proceed to the next stage of the rule change process suggests that the MAC may wish to consider a number of areas. Three such areas of concern are identified below as needing market review before such a concept as a dynamic Relevant Demand calculation could be further entertained by the market.

1.0 Nature of the Capacity Market

The first comment relates to the nature of the Reserve Capacity Mechanism (**RCM**), which is a long-term capacity mechanism that credits capacity some 2½ years before it is expected to perform. This is unlike other electricity markets that encourage sufficient capacity to be available through high energy price signals, or require capacity to be available for tomorrow through a short-term capacity mechanism. In this context, Synergy's first concern is how well a very short-term baseline approach, as suggested in the PRC, performs in a long-term capacity market. No evidence was presented in the PRC of how the proposal would improve or even achieve the long-term requirements of the RCM.

Given the structure of the RCM, being long-term with a focus on ensuring sufficient capacity is available for the year well in advance of the current year, contemplating a dynamic baseline approach to Demand Side Programmes (**DSP**) would, in Synergy's view, change the RCM's fundamentals. A dynamic baseline approach would increase uncertainty for the IMO in respect of whether the DSP provider has arrangements in place to deliver the level of capacity that was credited in Year 1 of the Reserve Capacity Cycle.

The current arrangement for assessing Demand Side Management (**DSM**), based upon the summer peak period in Year 1 of the Reserve Capacity Cycle, allows a reasonable prediction of expected capacity to be determined by the IMO such that they can be confident sufficient capacity is available 2½ years ahead when Reserve Capacity Obligations apply. The proposed arrangement, based on a dynamic baseline, has the potential to reduce the reliability of the IMO's security of supply forecast.

Similarly, the use of the summer months' peak (being the 32 reference points) and later (if approved) the Individual Reserve Capacity Requirement (**IRCR**) reference points, gives the IMO surety that the DSP provider has sufficient capacity before the commencement of the Capacity Year. The removal of the summer assessment values and its replacement by a value determined shortly before the Trading Day, or on the Trading Day itself, removes from the IMO any possibility of earlier capacity certainty as is required with the RCM. In other words, this is inconsistent with the RCM. Given the increasing volume of DSP capacity, uncertainty well in advance of the start of the Capacity Year weakens the IMO's ability to determine whether a supplementary capacity auction will be required or not.

Synergy's view is that the proposed dynamic baseline approach, although suitable for a short-term capacity mechanism, can be problematic or contradictory if introduced into the longer-term design needs of the RCM. Before any further consideration of such a proposal the market needs to understand and be comfortable in answering the question whether, and to what extent, a short-term capacity assessment fits with a long-term RCM.

2.0 Differential Treatment Compared to Generators

2.1 Issues with the current approach

The application of a dynamic baseline calculation allows DSP providers to adjust capacity available from individual loads throughout the year. Without such adjustments the market could be paying too much for capacity if at other times of the year the total demand was less than the baseline value. The current and RC_2010_29 method of baselining could create a free rider possibility and this is clearly an issue the market needs to review.

A weakness of the EnerNOC proposal is that it does not remove this risk given there is no adequate market checks on what capacity is available from a DSP provider. The only proof occurs with the annual test, undertaken at one time in the year, and in the event that the DSP is called upon to provide capacity. This uncertainty may also indicate that with a dynamic baseline approach the single capacity testing regime used as part of the commissioning process is not sufficient to assure the IMO that DSP capacity, to the level credited, is available at all required times.

Another consideration more important to a DSP provider than the market generally would be the possibility that its total DSP demand at certain times during the year could be higher than the summer defined baseline. If a higher than baseline demand occurred at the same time a dispatch instruction was issued then this would require the DSP provider to curtail more load than thecredited obligation by first having to reducing to the baseline.

The above possible situations describe the practical elements in using load for capacity purposes given their demand is not consistent throughout the year but varies seasonally, if not more frequently[1]. Although Synergy recognises this reality, to be consistent with the market objectives, we must raise the question: Should the same flexibility as requested in the proposal be afforded to generators in the market, either scheduled or intermittent?

2.2 Differential treatment compared to generators:

Under the dynamic approach, a load that increases in demand within the year can provide a greater proportion of the capacity obligation whereas a shrinking load would provide less. On balance, the total capacity obligation could still be met from the DSP's diversity of loads, avoiding the expense of capacity refunds.

This level of flexibility is different from that available to a fleet of generators which has a fixed value for each Facility for the year: this value is determined not on the previous 10 days performance but the at output at 41 degrees, even though some facilities within a fleet, such as gas turbines, can significantly increase their output in the milder seasons. Even Intermittent Generators (better described by Vestas Wind Systems as Variable Generators), as part of a fleet, with reasonable forecasting could reliably provide more capacity at different times of the year.

Synergy suggests that if a DSP is allowed to modify its baseline for individual loads through the year then similar provisions would need to be considered for a fleet of generators. Failure to address this could result in certain technologies being treated unfairly. In other words, in electing to move from a static to a dynamic capacity measurement base for one technology, the market is obliged to consider, on the basis of equity as embodied in market objective (c), whether a similar change is applicable to other technologies.

3.0 Disconnection of IRCR and Reducible Capacity

The introduction of a dynamic baseline approach would create a disconnection between how a load's IRCR is determined and its ability to provide capacity to a DSP. The current approach, and also that proposed in RC_2010_29, limits the level of capacity for an individual load to its peak demand as measured by the median of the 32 or 12 peak values. Using a baseline based upon the previous 10 days removes the link between a load's IRCR determination and the capacity that a load can, in turn, contribute to the market.

Synergy's concern here is that such a development would compound the already existing weakness in the RCM whereby a load can avoid any capacity requirement simply by removing its demand (turning itself off) during the 12 peak reading times. This is further explored below.

[1] The market should consider limiting the capacity obligation on DSP to the summer period given this is the peak period needing the most peaking capacity.

3.1 The existing RCM weakness

When a load predicts the likely peak trading intervals and so deliberately reduces its demand simply to minimise its future IRCR cost, it is signalling to the market it does not need capacity to be built to cover its actual capacity demand requirements for the rest of the year. This action would be OK if the load did not, at any other time during the year, exceed its demand attained during those 12 peak trading intervals after it instigated a demand reduction.

What we expect is that loads attempting to reduce their IRCR would reduce their peak demand below their average annual demand and so transfer part of the cost of their capacity needs onto the rest of the market. The possibility of loads being able to reduce or extinguish their IRCR was well understood by policy makers before the market commenced but was not acted upon because although it results in a cross-subsidy to the load reducers from those who do not, at that time it was seen as a low risk outcome. However, growing customer understanding of the IRCR component of the RCM and the rapid increase in the Reserve Capacity Price when combined with the opportunity for loads to receive capacity payments will potentially create a new dynamic that will result in a growing level of IRCR cross-subsidy between customers.

The IMO has, in the past, casually suggested that the IRCR mechanism could be transformed into a requirement based upon energy consumed rather than the current arbitrary approach of using the 12 summer peak intervals. One approach could be to determine the IRCR over more trading intervals, maybe 250 peak intervals, to avoid loads being able to free-ride their capacity requirement for the rest of the year. The point here is that the market, by defining IRCR over a very small sample (i.e. the 12 values) allows better placed customers to take advantage of the RCM's weakness and this is an equity concern needing to be remedied.

3.2 The proposal compounds this RCM weakness

For discussion purposes, take the case of a load that completely turned off during the 12 peak intervals to register a zero IRCR. The market would therefore plan and build no capacity for this load. A logical and unassailable conclusion from this is that, as this load did not purchase any capacity because of its zero IRCR, it does not have rights to any capacity that it could on-sell back to the market at other times of the year. Put simply, if the load is, by definition, not part of the RCM then it is infinitely curtailable as it has no rights to any capacity and therefore clearly has no rights to sell that capacity back to the market.

Now to allow a situation to develop whereby a zero IRCR load participates in the RCM as a capacity provider, and receives a payment from the market because at other times of the year it places a demand on the market, though as described above it has no right to that reliable supply, would be an absurd outcome. If this outcome were to prevail, i.e. that a load can contribute capacity in excess of its IRCR, then it suggests that the market has created a right to revenue for the supply of capacity that a provider had no right to dispose of in the first place.

The present arrangement limits the volume of capacity that a load can be credited for, or would be able to contribute as part of a DSP, is related to its IRCR and the actual amount of capacity that load has caused to be procured for the market. Unfortunately, the PRC_2011_01 proposal removes this limit by separately determining the baseline volume to the load's IRCR and therefore allowing a DSP load to provide more capacity than its IRCR. At the minimum, equity considerations clearly suggest that the current constraint precluding free capacity riders also getting a capacity payment needs to be maintained.

Obviously, even the most flexible loads are unlikely to be able to reduce their IRCR to absolutely zero. The zero IRCR example is presented here to make the general point that the detail of this proposal is more complex than initially considered by the MAC and so deserves serious review by the market before the proposal can be progressed as a formal Rule Change.

4.0 Conclusion

Synergy has identified three general areas in the RCM that would be impacted by PRC_2011_01, all requiring further consideration by the MAC. It is possible that there exist other areas of concern not identified here by Synergy. These and the issues raised by Synergy should be investigated by the market as a pre-condition to PRC_2011_01 progressing.

In this light, Synergy considers the EnerNOC PRC paper fails to address relevant market issues and so at this stage it is Synergy's view that the MAC has had insufficient opportunity to fully consider its implications or compatibility with the RCM.

5.0 Further Comment - Application of Refunds

If the market were to entertain PRC_2011_01 further, then an interesting application of a dynamic baseline approach is that it establishes a simple method for the IMO to undertake a high level check for DSP availability. Given the baseline is set from the previous 10 days the IMO could check previous demand levels and determine if sufficient demand was present for any trading interval to match at least the DSP capacity obligation. If, in any trading interval, the value was less than the capacity credit, then refunds would apply.

In suggesting the above, a minimum load demand would also be recommended, though Synergy suspects with a dynamic baseline approach, a minimum demand being the lowest demand a load can achieve becomes an essential requirement.