RCP | Rule Change Panel
Market Advisory Committee

RC_2019_01: The Relevant Demand calculation – Paper for MAC Workshop

20 July 2020

1. Background

Enel X submitted Rule Change Proposal RC_2019_01 to the Rule Change Panel (**Panel**) on 29 April 2019. The Panel sought further clarification on some aspects of RC_2019_01 and Enel X provided the clarifications on 21 June 2019.

The Panel decided to progress RC_2019_01 and published the Rule Change Notice and Proposal on its website on 28 June 2019. The first submission period was held between 28 June 2019 and 9 August 2019. The Panel received submissions from AEMO, the Australian Energy Council, Perth Energy, Synergy and Water Corporation.

The Panel has a assigned an urgency rating of 'Medium' to the Rule Change Proposal.

On 26 August 2019, the Panel has extended the timeframe for the publication of the Draft Rule Change Report until 30 June 2020 to give it time to hold workshops to develop drafting for this Rule Change Proposal and to prepare the Draft Rule Change Report while also managing competing priorities.

In Gazette 2020/24, published on 21 February 2020, the Minister has provided that from October 2021 all Demand Side Programmes (**DSP**) will receive the same Reserve Capacity Price for their Capacity Credits as other Facilities. The Panel considers that this change is likely to increase the participation of DSPs in the Reserve Capacity Mechanism, increasing the relevance of RC_2019_01. However, due to the timing of the changes to the Reserve Capacity Price for DSPs, RCP Support considers that the urgency rating of the Rule Change Proposal remains appropriate.

The Rule Change Notice and Proposal are attached for convenience. The submissions received in the first submission period are published on the Panel's website.

2. Purpose of MAC Workshop

The purpose of the Market Advisory Committee (**MAC**) workshop is to support the development of the design elements and Amending Rules for RC_2019_01. RCP Support asks stakeholders to discuss the following issues in this workshop to support the progression of RC_2019_01:

(1) Appropriateness of the proposed criteria for choosing the baseline as outlined in section 3.1 of this paper.

(2) Whether the Relevant Demand in the WEM should be based on a static baseline or a dynamic baseline?

(3) Which methodologies for determining a baseline are appropriate for the WEM?

(4) Should there be a single baseline approach for all DSPs or different baseline approaches for different types of DSPs/Associated Loads?

(5) On which basis should Capacity Credits be assigned to DSPs?

(6) How can the availability of DSPs be monitored for Capacity Cost Refunds?

(7) What is the appropriate timeframe to further progress of RC_2019_01?

RCP Support has undertaken some preliminary research and held discussions with AEMO to support the discussion:

- AEMO's and RCP Support's preliminary consideration of the above agenda items are provided in section 3 of this paper; and
- an overview of RCP Support's preliminary research of possible baselines, including descriptions, is provided in section 4 of this paper.

RCP Support notes that a second workshop could be held or a call for further submissions could be issued to discuss the following issues, depending on the outcome of the first workshop:

(8) How should Verification Test for a DSP be undertaken?

(9) How should Reserve Capacity Testing for a DSP be performed?

(10) How will the new baseline interact with IRCR?

3. AEMO's and RCP Support's Preliminary Consideration of the Agenda Items

3.1 Proposed Criteria for Choosing the Baseline

- **Decision-making criteria**
  - the Wholesale Market Objectives;
  - cost; and
  - practicality.
- **Additional decision-making criteria**
  - Accuracy:

    Described by the following statistical measures:
    - Bias: Measured by the average error that is the systematic tendency of a baseline method to over- or under-predict actual loads.
    - Variability: Measured by the error ratio, or the average standard deviation of the errors divided by the average load during the period. Determines the baseline's ability to predict hourly load under many different conditions and across many different customers.
  - Simplicity:
    - The baseline should be relatively simple for all stakeholders to understand, calculate and implement.
    - Preferably stakeholders should be able to determine the baseline in advance of/during DSP events (i.e. when the DSP gets dispatched) so curtailment performance can be monitored in real time.
  - Integrity: The methodology should not encourage or allow customers to distort their baseline through irregular consumption or to game the system.

- Administrative costs: The associated costs of activities such as data transfer, data quality review, analysis, training, required IT systems and compliance reviews etc should be justifiable.

- **Phases of a Demand Response (DR) event**
  - Ramp Period – where the Load ramps down to the level it is dispatched to (only applies if the Load was consuming prior the dispatch interval).
  - Sustained Response Period – the period where the Load stays at the committed level of curtailment.
  - Recovery Period – where the event is over, and the Load resumes normal operations.

- **Registration Process:**

  ERCOT evaluates and authorises the best performing baseline for each participant as part of the registration process. The participants ultimately select the baseline of their choice from authorized baselines. There are usually several to choose from, but occasionally there is only one method to choose from.

  In PJM, all DSPs must use a customer baseline with a relative root mean square error (**RRMSE**) no greater than 20% unless otherwise approved by PJM.

- **Software Requirement:**

  Alstom has acquired Utility Integration Solutions, Inc. (**UISOL**) for demand response management. The process is very automated with UISOL software, providers sign into the system, submit the meter data, and the software calculates the baseline. This software is used by Midwest ISO, PJM and CAISO.

- **Other Considerations:**
  - Possible Functionality of Relevant Demand in the WEM beyond the RCM:
    - Currently DSPs participate in the Reserve Capacity Mechanism and get dispatched through the Non-Balancing Dispatch Merit Order (that is after the Balancing Merit order has been exhausted). Could DSPs in the future potentially participate in the Balancing Market or LFAS Market or provide Ancillary Services with the proposed relevant demand methodology?
  - Customer Segmentation/load pattern:

    One of the goals of baseline evaluation based on the criteria discussed above is to determine whether customers should be segmented and then aligned to different baselines to achieve more accurate results. The following customer segments can be chosen to be evaluated as part of the analysis:

    - customer with variable loads;
    - customers with weather sensitive loads;
    - customer segments such as the agricultural sector, commercial property sector, manufacturing sector, mining Sector and refrigerated storage sector; and
    - regional customers.

3.2 Should the Relevant Demand in the WEM be Based on a Static Baseline or a Dynamic Baseline

A static baseline is uniform for all Trading Intervals and is appropriate for flat loads, whereas a dynamic baseline may vary with the Trading Intervals. A dynamic baseline can better accommodate varying load profile and system's peak period.

As proposed by Enel X, a dynamic baseline may be better suited to allow a more effective use of DSPs which do not have a flat load profile but may be still suitable to provide Reserve Capacity. Therefore, a dynamic baseline may be technically better suited for the WEM than a static baseline. A dynamic baseline should be implemented to calculate the Relevant Demand for Associated Loads where a DSP is dispatched either because of a test or because it is needed to reduce system load.

The decision whether a dynamic baseline should be implemented for the determination of Relevant Demand will depend on the relevant cost benefit analysis.

3.3 Which Methodologies for Determining a Baseline are Appropriate for the WEM?

A non-exhaustive list of possible baselines and descriptions of how they work is provided in section 4 of this paper, based on RCP Support's initial research. Based on analysis published by the Federal Energy Regulatory Commission (**FERC**) and the US Department of Energy (**DOE**), PJM and AEMO:[1]

- the X of Y method may be best suited for most DSPs – the 4 of 5 baseline with additive adjustment (as used by PJM) may be preferable because of its performance and ease of administration;
- the Meter-before/Meter-After baseline could be a preferred option for DSPs with a flat load profile; and
- the Nearest Like or Matching Day model may not be suited for the WEM because there is a possibility that a matching day does not exist or the criteria to find a matching day may not be holistic, so this method may not truly reflect a given event day.

3.4 Should there be a Single Baseline Approach for all DSPs or Different baseline approaches for Different Types of DSPs/Associated Loads?

A single baseline may not give the most accurate results for a range of customer segments, so it may be favourable to adopt different baselines based on the cost benefit ratio. However, this will depend on the relevant cost benefit analysis.

[1] "Measurement and Verification for Demand Response – Prepared for the National Forum on the National Action Plan on Demand Response: Measurement and Verification Working Group" published by FERC and DOE https://www.ferc.gov/industries/electric/indus-act/demand-response/dr-potential/napdr-mv.pdf

"PJM Empirical Analysis of Demand Response Baseline Methods" published by PJM https://www.pjm.com/-/media/markets-ops/demand-response/pjm-analysis-of-dr-baseline-methods-full-report.ashx?la=en

"Development of Demand Response Mechanism Baseline Consumption Methodology – Phase 2 Results Final Report" published by AEMO https://www.aemo.com.au/-/media/Files/PDF/Baseline_Consumption_Methodology_Phase_2_Report_Oct13.pdf

3.5 On which Basis should Capacity Credits be Assigned to DSPs?

Capacity Credits are currently assigned to a DSP based on information provided to AEMO including:

- information which loads are contracted by the relevant Market Customer and the amount by which the loads are contracted to reduce their consumption; and
- the Relevant Demand of the contracted loads at the time of certification (usually the data the Relevant Demand Calculation is based on is from four years before the year in which the Capacity Credits apply).

The contract information may be sufficient to assign Capacity Credits to DSPs and consumption data from four years before the year for which the Capacity Credits apply would in many cases not provide an efficient estimate of the load's available capacity.

3.6 How can the Availability of DSPs be Monitored for Capacity Cost Refunds?

Currently, in each Trading Interval a DSP must fulfil the following requirement:

$$DSP\_Relevant\_Demand - DSP\_Minimum\_Load \geq DSP\_RCOQ$$

Where:

- o DSP_Relevant Demand is the DSP's Relevant Demand;
- o DSP_Minimum_Load is the sum of the Minimum Consumption of the DSP's Associated Loads; and
- o DSP_RCOQ is the DSP's Reserve Capacity Obligation Quantity (**RCOQ**).[2]

Obviously, this approach would not work if a dynamic baseline was used to calculate a DSP's Relevant Demand.

However, not including a form of continuous monitoring if DSPs meet their Reserve Capacity Obligation could:

- increase the risk that the capacity would not be available when it is needed; and
- be against Wholesale Market Objective (c).[3]

The assessment of whether the DSP is sufficiently available could be based on the DSP's actual consumption instead of the Relevant Demand. Requiring that the for each Trading Interval basically:

$$DSP\_Load - DSP\_Minimum\_Load \geq DSP\_RCOQ$$

Where:

- o DSP_Load is the total consumption of the DSP's Associated Loads

AEMO already has to determine the actual consumption of DSPs for every Trading Interval (clause 6.16.2). Such an approach would require an allowance for a certain amount of Trading Intervals where the requirement is not met without the DSP incurring refunds, similar to the outage allowance for Scheduled Generators.

2 A DSP's Reserve Capacity Obligation Quantity equals the assigned Capacity Credits but equals zero for Trading Intervals which fall outside of the periods when the DSP can be dispatched or if the DSP has already been dispatched for the maximum of hours for the day or Capacity Year.

3 Wholesale Market Objective (c) is:

> 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.

3.7 Timeline for Progression of RC_2019_01

The following are tentative milestones for discussion by the MAC:

- 20 July 2020: MAC workshop to discuss issues and design options;
- August 2020: RCP Support and AEMO discuss outcome of MAC workshop and preferred options;
- October 2020: AEMO to confirm high-level assessment of the cost and practicality of the preferred options for dynamic baselines (i.e. order of magnitude assessments of cost and timing, including earliest that implementation development can commence); and
- December 2020: RCP Support to further consult with Market Participants and/or to develop a Draft Rule Change Report.

4. The Rule Change Proposal

4.1 Definition of Relevant Demand

Enel X proposes to change the definition of Relevant Demand to:

> An estimate of a DSP's counterfactual demand, when it is dispatched.

4.2 Implementation of a Dynamic Baseline

Enel X proposes to replace the current methodology for calculating a DSPs Relevant Demand with a baseline methodology for DSPs that strikes an appropriate balance between accuracy, simplicity and integrity.[4]

Enel X considers that the current method, using a low, static baseline not only under-calculates and undervalues the potential of DSPs but results in a very inaccurate picture of the DSPs' expected consumption in majority of the hours.

Dynamic baseline methodologies have the potential to measure baseline consumption much more accurately than static approaches because they are capable of taking into account a DSP's variability over whatever hours it is actually dispatched.

Enel X advocates implementing a dynamic baseline methodology for DSPs that accounts for a Load's variability when calculating a DSP's Relevant Demand. Enel X is of the view that an "X of Y"[5] methodology is best suited for the WEM. Enel X also suggest that it may not be necessary to settle on one specific approach. Many international markets offer a range of baseline methodologies so that the most accurate one can be chosen for each site.

4.3 Availability Monitoring

Enel X notes that most capacity markets worldwide do not impose any obligation on the system operator to monitor availability to gain assurance that capacity providers will be able to deliver the capacity they have been credited for. Therefore, Enel X is of the view that

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4 Accuracy – customers receive credit for no more and no less than the curtailment that they provide.

Simplicity – the methodology makes baseline and curtailment calculations easy to calculate and easy for customers to understand.

Integrity – the methodology does note encourage irregular consumption, and irregular consumption does not influence he baseline calculations (i.e. protects against the ability to "game the system").

5 The "Y" is a Load's expected demand drawn from data from a number of previous days and "X" is a subset of these "Y days" to obtain a representative sample.

continuous availability monitoring of demand side programmes is not required. Rather, any concerns about a DSP's ability to meet its reserve capacity obligations are better addressed through security, testing and penalty frameworks.

5. Relevant Demand Calculation in the WEM

5.1 Current Methodology

Under the current methodology set out in the Market Rules, AEMO calculates the Relevant Demand for a DSP as follows:

(1) identify the 200 Calendar Hours in the previous Capacity Year with the highest Total Sent out Generation (the Calendar Hours do not have to be contiguous);

(2) identify the metered consumption for each of the DSP's Associated Loads for the 200 Trading Intervals of each Calendar Hour identified under (1);

(3) for each Calendar Hour, sum the values for each of the DSP's Associated Loads identified under (2);

(4) for each DSP, rank the 200 values determined under (3) from lowest to highest; and

(5) the Demand Side Programme's Relevant Demand is the tenth lowest value.

Under the current Market Rules, AEMO calculates the Relevant Demand for each DSP on a daily basis. This means that a DSP's Relevant Demand can change from one Trading Day to the next due to changes in meter data, which may affect the selection of the 200 Calendar Hours under step (1) or the consumption of any of the DSP's Associated Loads.

5.2 Previous Methodology

Under the previous methodology, AEMO had to calculate the Relevant Demand for a DSP as follows:

(1) identify the eight consecutive Trading Intervals with the highest aggregate system demand in each month during the Hot Season of the previous Capacity Year;

(2) determine the metered consumption multiplied by two (to convert from MWh to MW) for each of the DSP's Associated Loads for the Trading Intervals identified under (1);

(3) for each Trading Interval determined under (1) sum the values determined under (2) for all of the DSP's Associated Loads; and

(4) the DSP's Relevant Demand is the median of the 32 values determined under (3).

6. Relevant Dynamic Demand Baseline Types

The following are the major dynamic baselines used by other system operators for different types of loads providing demand side management:

- **Statistical Regression Model**

  The following formula outlines a generalised form of a Statistical Regression Model used by ERCOT:

  $$kW^{e}_{d,\,h,\,int} = F(Weather_d, Calendar_d, Daylight_d)$$ [6]

  Within this general specification, there is an unlimited number of detailed specifications that involve different types of data (such as hourly versus daily weather variables) and different functional specifications that can be used to capture specific nonlinear relationships and variable interactions. This breakdown allows development of a robust and relatively rich daily energy model that relies primarily on daily weather and calendar information.

  PJM analysis of different baselines suggests that, regression analysis have similar performance as X of Y methodology. However, the administrative costs and associated complexity of the regression approaches are significantly higher than those of the X of Y approaches.

- **Meter-Before/Meter-After Model**

  This model is usually used only for fast-response programs and reflects actual load changes in real-time. For this model the energy consumption during the trading interval that ends immediately preceding the dispatch instruction is used as the baseline for all subsequent intervals. This model is used both by PJM and ERCOT. This baseline is usually suitable for consistently flat loads.

- **X-of-Y Like Days Model**

  This concept is used widely in many jurisdictions such as CAISO, NYISO, PJM, ERCOT, with numerous variations especially on the number of days to evaluate. CASIO uses 10-of-10, NYISO used 5-of-10, PJM uses 4-of-5 and ERCOT has concluded that 8-of-10 produces the best results.

  ERCOT's approach consists of the following steps:

  (1) identifying the 10 (Y) days having the same day-type as the event day;

  (2) calculating the energy consumption for each of the ten (X) days and eliminating the day with the highest consumption and the day with lowest consumption; and

  (3) averaging the interval consumption for the eight remaining days for each interval.

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6 Where: e is the DSP's ID;
d is a specific day;
h is an hour on day d;
int is a 15-minute interval during hour h;
kW is the average load for a DSP's ID in a specific interval;
Weather represents weather conditions on the day and preceding days;
Calendar represents the type of day involved; and
Daylight represents solar data, such as the time of sunrise and sunset.

The result of this is the unadjusted baseline. The data selection rules ERCOT uses for choosing the Y days are:

- proximity to the event;
- similarity of load; and/or
- similarity of weather.

Exclusion rules to eliminate some of the Y days can be based on eliminating highest or lowest demand days or choosing middle days. The days left after applying the exclusion rules can be referred to as X days. These X days are averaged to calculate an unadjusted baseline. ERCOT also allows for further adjustment of the baseline (e.g. by applying a factor to the baseline to account for temperature differences).

The PJM Economic Baseline consists of the average of the hourly consumption across the "highest X out of Y" most recent days.

- For weekday events, the baseline consists of the average hourly consumption of the four highest kWh days out of the five most recent weekdays preceding the event, excluding holidays, weekend days, and event days.
- For weekend or holiday events, the baseline consists of the average hourly consumption of the two highest kWh days out of the three most recent weekend or holiday days, excluding event days.

The baseline consumption for each event hour is set by the average consumption during the respective hour on the selected comparison days.

The key factors of X of Y methodology include:

(1) Look-back Window – The range of days prior to the event that are considered (i.e. the value Y).

(1) Exclusion rules – Some days are excluded from consideration in Y, such as holidays, previous DR event days, weekends, thresholds and scheduled shutdowns (as these are not representative of "normal" operation).

(2) Ratio of X to Y – The selected subset of X days in the range of Y days relates to the characteristics of the DR program and the customer's general energy usage patterns.

(3) Baseline adjustments – Adjustments are based on day-of-event load conditions to improve baseline accuracy. Adjustments may also be made based upon weather, calendar days, etc.

(4) Multiplicative vs. Additive Adjustments – Multiplicative adjustments reflect percentage demand comparisons and additive adjustments reflect actual differences. Additive and multiplicative adjustments both use the difference between the baseline and observed load, but the additive adjustment is constant across the entire event period while the multiplicative adjustment adjusts as a percentage of loads during the event period.

(5) Capped vs. Uncapped Adjustments – Limits to adjustments.

(6) Symmetric vs. Asymmetric Adjustments – Symmetric adjustments can increase or decrease the baseline while asymmetric adjustments only allow adjustment in one direction.

(7) Aggregation level – Calculations can be done at the Associated Load level vs. at a DSP level.

PJM analysis of DR baseline method indicates that a same day additive adjustment has superior performance to an unadjusted baseline. The X of Y with a same day additive adjustment have similar results and performed well across all segments, time periods and weather conditions, except for predicting loads for variable load customers.

- **Nearest Like Days Model**

  The load for a demand side management site during a specific number of days[7] of the same day-type that occur close to a dispatch event is averaged for each interval. The result of this is the unadjusted baseline. This model is used both by PJM and ERCOT.

- **ERCOT Matching Day Pair Model**

  Intervals for past days (matching days) from the preceding year are matched with the corresponding intervals of the event day. The ten best available matching days are identified and the average for consumption over all matching days is calculated for each interval to determine an unadjusted baseline. As this model matches a day based on defined variable uniform with the event day, there might not be a day to use as the proxy day.

- **ISONE Standard Baseline**

  For a new asset with no previously computed baseline, the baseline is the simple average half hourly load calculated for each half-hour of the day from the five most recent preceding business days with complete meter data. For an existing asset (i.e. one with at least five days of usable load data), the current-day baseline is obtained as follows:

  - If the current day is an event day, the asset's baseline for the day is equal to the baseline from the previous day.
  - If the current day is not an event day, then the asset's baseline is updated according to the following algorithm:

    Current day baseline = 0.9×previous day baseline + 0.1×current day metered load for each half hour of the current day.

- **Maximum Base Load**

  Maximum Base Load (MBL) is a static technique that utilizes data, often from the previous year, to draw a line at a certain power level below which the customer must maintain demand when called upon. This demand level is often non-representative of current load conditions due to changes within the customer's facility. This technique often bases the MBL on previous year peaks either coincident or non-coincident with system peaks. A coincident MBL baseline uses peak hours of summer chosen based on system load peaks where a non-coincident baseline uses peak hours determined by individual Load behaviour not system Load. MBL is used by NYISO. MBL is simple to implement but may not suitable for variable loads.

[7] PJM uses 45, whereas ERCOT uses 20 most recent days