Executive Summary

This paper proposes compensation guidelines for Load Registered Facilities (“LRF”s) providing Interruptible Load (“IL”) services that are interrupted beyond 120 minutes.

At the 107th RCP meeting, the RCP endorsed the proposal to set a maximum interruption duration of 120 minutes of IL activation, beyond which IL service providers should be allowed to seek compensation. To provide certainty on the treatment of such compensation requests, the RCP tasked the EMC to develop appropriate guidelines to calculate compensable amounts for ILs interrupted beyond 120 minutes (i.e., “prolonged interruption”).

Existing compensation frameworks were assessed to be inapplicable for LRFs facing prolonged interruption. The EMC surveyed IL products in the PJM, NYISO, KPX, and IESO to extract transferrable principles to design a compensation method. While the usage of individualised Energy-Bids and Emergency Strike Prices would be ideal, operational realities suggest that these are challenging to validate as reflective of “true” cost. In variant cases where price caps are instituted, the use of bids and strike prices would do no better than administratively determining a fixed compensation amount for LRFs.

Our assessment of bid/strike price-based methodologies is that they are impractical. Therefore, EMC proposes for compensation amounts to be determined based on benefit to the system – referencing the value of IL provided to the market and/or the system cost avoided owing to prolonged interruption. The compensation amount can be based either on (1a) the prevailing Market Energy Price (“MEP”) at relevant network nodes, (1b) the prevailing USEP to discount locational effects, or (2) the variable cost of the Marginal Generating Unit.

After considering stakeholder’s feedback on the practicality of the options, EMC recommends for the RCP to discuss and adopt option 1(b) for the compensation of LRFs that have been interrupted beyond 120 minutes after a contingency reserve activation.
At the 116th RCP meeting held on 12th May 2020, the RCP by majority vote supported: (1) the adoption of Option 1, in principle: to base the IL compensation amount calculation on the prevailing USEP/MEP, or a variant of it; and (2) tasked the EMC to study Option 1 in further detail and draft the compensation guidelines and necessary market rule modifications to make reference to the guidelines should LRFs request for compensation.

Upon further study of Option 1, the EMC proposes: (a) the use of the prevailing USEP as the reference price to compute compensation amounts for LRFs across affected periods, and (b) for the RCP to endorse the compensation guidelines as set out in Appendix C. At the 117th RCP meeting held on 14th July 2020, the RCP by majority vote supported: (1) the compensation for LRFs facing prolonged interruption to be based on the prevailing USEP, as set out in the compensation guidelines in Appendix C; and (2) to task EMC to draft modification to the Market Rules in order for the compensation guideline to be used as the basis for the calculation of compensation amount.
1. Introduction

This paper proposes compensation guidelines for Load Registered Facilities (“LRF”s) providing Interruptible Load (“IL”) services that are interrupted beyond 120 minutes (“mins”) during a contingency event.¹

2. Background

2.1 Proposal

At the 107th Rules Change Panel (“RCP”) meeting in March 2019, the RCP by majority vote supported introducing compensation for IL facilities that have been interrupted beyond a duration of 120 mins after activation.² The RCP’s decision effectively stipulated a soft limit on the interruption duration expected of IL facilities dispatched for reserves. Despite the soft limit, under high-risk or emergency operating states circumstances, the PSO may require LRFs to be interrupted beyond 120 mins to safeguard system security. Allowing compensation for such scenarios will preserve the PSO’s flexibility to leverage available resources for managing system security while providing recourse for LRFs who have been interrupted beyond the soft limit specified in the IL product.

Arising from their discussion, the RCP tasked EMC to develop an appropriate methodology to determine the compensable amount for LRFs facing prolonged interruption beyond 120 mins after contingency reserve activation.³

2.2 Design Principles Considered for Compensation Methodology for IL

The methodology should be aligned with existing compensation frameworks as far as possible. Where these frameworks are found to be inapplicable, the EMC should propose enhancements for the RCP’s consideration. Since market inception, the RCP has endorsed various compensation frameworks, while certain compensation methodology for specific scenarios have been put into effect under the Market Rules.⁴

Economic efficiency is the overarching principle that governs the existing compensation frameworks. Under the Singapore Wholesale Electricity Market (“SWEM”)’s uniform pricing regime, MPs are incentivised to offer close to their “true” marginal costs of production. Doing so ensures that MPs can recover at least their variable cost of production in the short-run, while scarcity rents allow fixed cost recovery via market returns in the long-run. These are sanity factors for MPs to operate sustainably in the SWEM and contribute to an economically efficient market.⁵

This model is premised upon the MPs’ offer prices being the best reflection of their costs, which serve as inputs to the EMC’s Market Clearing Engine (“MCE”). Consequently, the security-constrained dispatch schedule produced by the MCE is the most economically efficient outcome that should generally be adhered to for dispatch purposes.⁶

¹ Unless explicitly mentioned, LRFs are taken to be load facilities/premises that are participating in the IL scheme to provide contingency reserve to the real-time market.
² For more info on how LRFs participate in reserve provision, please refer to Paper No. EMC/RCP/107/2019/356: Restoration of Load Registered Facilities Activated to Provide Reserve.
³ For avoidance of doubt, LRFs are advised to revise their reserve offers upon activation to properly reflect their actual capability to provide further reserves.
⁵ For a detailed discussion, please refer to Section 3.1, pg. 4 of Paper No. EMC/RCP/76/2014/325: Review of Compensation Guidelines.
⁶ Under Chapter 5 Section 9.1.2.1 of the Market Rules, the MCE-produced real-time dispatch schedule is deemed to be the default dispatch instructions by the PSO, unless otherwise instructed by the PSO.
However, during emergencies, the PSO may override the default dispatch instruction and instruct MPs to increase or reduce generation with respect to the default dispatch instructions. In these situations, payments to affected MPs based on ex-ante nodal prices may not adequately compensate them at the levels indicated in their offers. To provide MPs with the necessary confidence to operate and invest in the long-run, the RCP endorsed a non-binding offer-based compensation methodology to calculate the compensable amount.\footnote{Paper No. EMC/RCP/24/2006/CP11: Guidelines for Compensation}

Based on this methodology, MPs should be compensated based on the following:

- In the event where a GRF is instructed by PSO to increase its output, the \textbf{additional costs incurred} calculated based on energy offer;

- In the event where a GRF is instructed by PSO to decrease its output, their \textbf{forgone market returns} as a result of complying with the PSO's instructions. Where (1) \textit{forgone returns} for each dispatch period is calculated as the difference between \textit{market returns} from adhering to the default dispatch schedule as opposed to complying with PSO's subsequent dispatch instructions; and (2) \textit{returns} are calculated as the difference between market payments based on the periodic nodal price and the MP's nominal cost of production – calculated based on the MPs' \textit{offers} across the energy quantity scheduled or instructed.

Unlike compensation to generators that are constrained-on for energy at Minimum Stable Load, and those that are adversely affected by price revisions, the suggested compensation method for MPs that \textit{incur additional} costs or forgo \textit{market returns} due to compliance with PSO's dispatch instructions are currently non-binding, serving only as a reference for the PSO.

\subsection*{2.3 Other Design Considerations}

Other possible considerations when designing the compensation methodology include (but are not limited to):

\begin{itemize}
  \item \textbf{(1) Fair and neutral in determining compensable amounts.}
  \item \textbf{(2) Not creating perverse incentives} for participating entities.
  \item \textbf{(3) In the absence of sufficient energy offer quantities up to the instructed level, compensation amount can be calculated based on cost determined using the unit's LRMC (inclusive of fixed and variable cost) and other costs (i.e., start-up/shut-down costs, market charges) directly attributable to compliance with PSO’s instruction.}
  \item \textbf{(4) Creating administratively simple and cost-effective procedures, as far as possible.}
\end{itemize}

\section*{3. Analysis}

\subsection*{3.1 Current Framework is Inapplicable to IL Service Providers}

The current compensation framework suggests for reserve providers to be compensated based on their energy offer prices when instructed by the PSO to produce more energy than originally required by their total scheduled energy and reserve quantities. As reserve providers, LRFs facing prolonged interruption are in the same situation, where they are required to provide more load reduction than originally required under scheduled reserves.
However, unlike GRFs that are required to have accompanying energy offers to their reserve offers, LRFs do not have mandatory energy bids (i.e., offer equivalent) unless they are participating in the Demand Response Programme (energy curtailment based on economic dispatch) concurrently. Furthermore, standing energy bids in the activation period and successive periods after activation are not representative of the cost of interrupting IL facilities beyond 120 mins.

This is because the cost of interruption represented by each trading period’s standing energy bid relates to an isolated single-period curtailment event, without intertemporal considerations (i.e., determined independently from neighbouring periods). On the contrary, the LRF’s marginal cost is correlated across periods during prolonged interruption (this is elaborated more in Appendix A) and may require offer variations for subsequent periods upon IL activation to properly reflect its associated costs in a prolonged interruption.

In the subsequent sections, EMC will propose possible enhancements to the compensation framework with reference to IL participation in other jurisdictions.

### 3.2 IL Products/Programmes in Other Jurisdictions

A survey of IL participation in notable jurisdictions (PJM, NYISO, South Korea and Ontario markets) reveals noteworthy learnings and distinctions (a side-by-side comparison with IL participation in the SWEM can be found in Appendix B). In the jurisdictions studied:

1. IL facilities can provide reserves through the real-time ancillary services market (i.e., spinning reserves), emergency load response programmes entered through capacity auctions or out-of-market service contracts. Real-time ancillary services markets tend to have more demanding event notification periods (e.g., 10 mins prior to event) and shorter response durations (e.g., 30 mins), while capacity market and contracted services programmes procure resources with the capabilities for longer response durations (e.g., 10 hours) and are given a longer notification lead-time (e.g., 2 hours). Structuring the products and programmes in this way allows the Independent System Operators (“ISO”s) to maximise participation from resources of varying capabilities.

2. A maximum response duration and frequency of interruption is explicitly stated for the IL products/programmes – these specified boundaries are honoured and not overstepped. An exception is made for programmes tailored for seasonal periods (e.g., Summer: from June through September). These seasonal programmes often specify unlimited frequency of interruption, although there is still a strict cap on the duration of each interruption event.

3. The term “compensation” is interpreted as fair payment to a Load Facility for its services provided/contracted, as opposed to a form of recourse for requiring more than what is specified in a real-time/capacity market product or service contract. The latter interpretation does not apply to the jurisdictions surveyed as there are no instances where IL participants are interrupted beyond what is specified.

Compared to other jurisdictions, there are limited ways for IL participation in the SWEM. Barring primary reserve, which has poor participation from ILs, the only other viable way for IL participation is through the contingency reserve product, which requires a 10-minute response time upon notification and interruption for a non-specified maximum response duration. Such

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8 Under the Reserve Proportion Constraint (see Market Rules, Appendix 6D D.17.2), a GRF’s available raw reserves for scheduling is capped at a proportion of its generation amount, meaning that the GRF must be scheduled for energy in order to also be scheduled for reserves.

9 Refer to Appendix721 A for more details.

10 ILs providing primary reserve shall be capable of achieving its scheduled MW response automatically without further instruction from the PSO within 9 seconds of being triggered by any contingency event, and shall be able to maintain that scheduled MW response until 10 minutes from the time it was triggered. Most load facilities are unable to comply with the strict response time.
arrangements are not found in other jurisdictions. The IL scheme in the SWEM is, in contrast, disproportionately demanding on both the response time and the interruption duration required of IL providers. The possibility of interruption for an unlimited duration is also impractical to expect of IL providers, whose core business is not to provide reserves.  

While there are no comparable markets where IL providers are interrupted beyond the specified maximum response duration, there is still value to examine their reserve payment regimes to extract transferrable principles for our compensation methodology. For this purpose, emergency load response programmes that procure resources through capacity markets are more helpful references than real-time ancillary market products, as these programmes are used for dispatching multi-hour (long) duration interruptions.

3.3 Payment Methodologies in Other Jurisdictions

In the PJM, NYISO, South Korea and Ontario markets, demand side resources are cleared in the forward capacity auctions to participate in emergency load response programmes. Participating Load Facilities receive year/month-round capacity (availability) payments for being able to respond to emergency events, similar to how IL cleared to provide reserve is paid for being on standby in the SWEM. In addition, participating load facilities receives utilisation/energy payments during an event of activation.

U.S. – PJM and NYISO

In the PJM and NYISO, utilisation payments during activation periods are based on the higher of the real-time Location Marginal Price (“LMP”) or the Minimum Dispatch Price specified by the load resource (or its market representative) in the event it is called upon.

The LMP-based methodology follows the Federal Energy Regulatory Commission (“FERC”)’s final ruling in year-2016 on compensation for Demand Response (“DR”) resources, through Order No. 745. Order No. 745 presents the thinking that load resources should be paid like other supply resources (i.e., generation) since they are providing a similar product of incremental value. This is consistent with the view that load resources participate in the PJM and NYISO markets as supply-side (rather than demand-side) resources, and thus must be compensated for reducing electricity load at the same rates as if they met that demand with generated electricity.

Both jurisdictions also require load resources to nominate a Minimum Dispatch Price that serve as an Emergency Strike Price to help the ISO prioritise which resources to call on during a reliability/shortage event. While the proposed prices are subject to administrative caps to avoid overpayment, the guaranteed strike price recovery provides loads with a level of payment certainty with each administrative dispatch. The PJM imposes an administrative price cap (year-2018) of $1,100-1,849/MWh, depending on the notification lead time (30-mins, 60-mins, 120-mins) that load resources qualify for. The strike prices are set before the delivery year and cannot be

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11 For this reason, we do not observe IL products/programmes with unlimited response durations required of its participant in the jurisdiction scan, as load facilities require a level of certainty to coordinate their core operations.

12 Participants in the real-time ancillary services markets only receive the market clearing price (i.e., reserve clearing price) for trading periods that they are cleared, with no event payment. For avoidance of doubt, reserve offer prices are a representation of the load facility’s cost to provide the option for curtailment during a contingency event. Hence, it is not a valid representation of the direct cost incurred to curtail the load of a load facility and is not suitable as the basis for determining compensation.

13 Traditionally, availability payments are used to compensate the service provider for the fixed costs associated with providing the service, while utilisation payments are used to cover the variable costs associated with providing the services. Fixed cost includes the initial investment in technology such as monitoring and controls software to manage and execute DR operational activities. Variable costs may include labour cost and loss of productivity during the DR activation period.

14 We chose the PJM as a reference out of other U.S. markets as it represented the most established market for demand/interruptible load responses participation in power markets.

15 The LMP represents the marginal value of the last unit of resource necessary to balance supply and demand at each node within an ISO or RTO.
changed during the delivery year. In the NYISO, the load resources can nominate a strike price up to a maximum of $500/MWh. A new strike price is set for each auction month.

Despite the FERC’s final ruling on compensation for load resources, some Regional Transmission Organisations (“RTO”s) and ISOs (PJM and NYISO inclusive) recommended compensating the DR providers as if they had first purchased the energy (e.g., in day-ahead markets or through other means) and then "reselling" the energy to the real-time market in the form of emergency service. This translates to a utilisation payment calculated as LMP minus "G", where "G" represents the retail price (often fixed) payable if the end-use customer exercises the option to consume. LMP – G thus represents the market value of the option – the payment due to the interrupted load resource. While this payment arrangement is not in effect, the embedded principles are useful for our reference.

**South Korea - KPX**

The emergency response programme by the Korea Power Exchange (“KPX”) provides utilisation payment for load resources activated for between 1- to 4-hours of interruption. The payment rate is priced at the Variable Cost of the Marginal Generating Unit (“MGU”) operating in the market. KPX’s pricing methodology assumes that if the load resource had not been interrupted, the marginal generator would have to incur additional cost to supply the energy demand from the load resources. Generators’ Variable Costs are determined in advance by the Cost Evaluation Committee and is an explicit representation of the "avoided cost" the generation system would have incurred in the absence of emergency response rendered.

**Ontario – IESO**

In Ontario, the Independent Electricity System Operator (“IESO”) proposes for utilisation payments to be based on submitted Energy-Bids by the load resources to indicate their individualised Value of Lost Load (“VoLL”). The IESO’s intent is for resources to be able to recover at least their incremental cost of interruption, without which they would be better off consuming. These “make-whole” payments were a means to manage the total cost of capacity auctions, as load resources will not have to incorporate activation costs into their auction offers.

Utilisation payment rates are calculated by subtracting the Hourly Ontario Energy Price (“HOEP”) from the nominated Energy-Bids. This serves to cover the cost of “producing” electricity in the form of curtailment (also known as “negawatts”), equivalent to the lost revenue and additional costs incurred (i.e., forgone returns) associated with a reduction in load/operations.

The IESO recognised that it is difficult for the administrator (and arguably for load owners as well) to know the “true” cost of out-of-market activations. Hence, as opposed to identifying the costs of individual or type of resources using costing frameworks based on detailed submissions on interruption costs, the IESO decided to use Energy-Bids as representative costs. There is no explicit mentioned in public literature of any active caps on the Energy-Bids that can be submitted.

### 3.4 Jurisdiction Scan and Proposed Options for SWEM

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16 DR auction procures DR resources as reliability/capacity resources. Participants offer into two seasonal DR auctions. Participants who clear the auction are required to be available to the IESO to meet peak demand. (Source: “Demand Response Discussion Paper, Utilisation Payments, Prepared for: IESO”, Navigant 2017)

17 These are termed as Emergency Operating State Control Action (“EOSCA”) activations and are treated as out-of-market.

18 The IESO qualified that it is not concerned about ensuring efficient (i.e., lowering) Energy-Bids. Rather, the objective of its proposed utilisation payment methodology is to achieve more efficient auction offers in the capacity market.

19 It is likely that that there will no out-of-market activation for load resources with Energy-Bid < HOEP, since the load resource would have been dispatched based on economic activation.
### 3.4.1 Payment Principles in Other Markets

Following section 3.3., Table 1 below summarises the principles underpinning utilisation payment in other jurisdictions.

<table>
<thead>
<tr>
<th>Jurisdiction</th>
<th>Methodology for Determining Utilisation Payment Rate</th>
<th>Underlying Principles</th>
<th>Implementation Challenges in SWEM</th>
</tr>
</thead>
<tbody>
<tr>
<td>PJM, NYISO (FERC Ruling)</td>
<td>Higher of LMP or Emergency Strike Price, where strike price is subject to administrative cap.</td>
<td>▪ Load resources <strong>seen as supply-side resources</strong> and compete with generators on a level playing field – should be paid like other supply resources (i.e., generation) since they are providing a similar product of incremental value.</td>
<td>In SWEM, DR resources are not seen as supply-side resources as payments for economic DR are a fraction (one-third) of the avoided cost to the system/additional consumer surplus generated.</td>
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<td></td>
<td></td>
<td>▪ Emergency Strike Price help the ISO to <strong>prioritise lower cost resources</strong> first during a reliability/shortage event. This incentivises DR resources to bid as close to their “true” cost of interruption as far as practicable.</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>▪ Guaranteed strike price recovery provides loads with a level of <strong>payment certainty</strong> with each administrative dispatch.</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>▪ Administrative cap to <strong>avoid overpayment</strong></td>
<td></td>
</tr>
<tr>
<td>PJM, NYISO (ISO Recommendations)</td>
<td>LMP – “G”, where “G” is the retail price that end-user consumes energy at.</td>
<td>Load resources should be <strong>paid as if they had first purchased the energy</strong> (e.g., in day-ahead markets or through other means) and then &quot;resell&quot; the energy to the real-time market in the form of emergency service.</td>
<td>May be challenging to administer because it requires PSO to determine the relevant purchase/retail rate for end-users or an aggregation thereof.</td>
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<tr>
<td>KPX (South Korea)</td>
<td>Marginal Generating Unit Variable Cost</td>
<td>▪ Load resources should be paid based on the <strong>generation system's avoided cost</strong>, which is calculated based on the</td>
<td>Would require sensitive information on generator variable cost from PSO to</td>
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</tbody>
</table>
The possible payment principles should also be assessed against design considerations highlighted in section 2.3, refreshed here for convenience: (1) Fair and neutral in determining compensable amounts; (2) not create perverse incentive for gaming; (3) calculate compensation based on LRMC and associated cost in the absence of energy offer quantities; and (4) create administratively simple and cost-effective procedures.

### 3.4.2 Applicability in SWEM

We examined the following compensation methods and its applicability in SWEM.

**Individualised Cost – Strike Price/Energy Bid**

Requiring IL participants to submit Minimum Dispatch Prices/emergency strike prices to define the incremental cost of interruption, and to a lesser extent, Energy-Bids as a representation of their individualised VoLL, would be most aligned with the current compensation framework for reserve providers. Some considerations when evaluating this option include:

1. **(1)** In the absence of an effective cap on the interruption duration, IL participants will need to provide a time-series of prices for the PSO’s consideration, since they are unable to provide a singular Energy-Bid/Strike Price by averaging costs across the maximum duration.

2. **(2)** Should the PSO choose to rank Strike Prices for the purpose of prioritising resources, prices expressed in time series are not straight-forward to rank as compared to singular prices, lacking usefulness to the PSO for prioritising the activation of lower cost resources, and the restoration of higher cost resources.

3. **(3)** In the absence of administrative price caps, bids/price may be unrestrained. On the contrary, prices are expected to cluster around imposed caps, if any (this is the experience in NYISO).

4. **(4)** The efficiency of the nominated bids/prices are also questionable as it is difficult to ascertain the "true" cost of prolonged interruption due to potentially multiple moving parts and explanatory variables, both from the regulator’s and LRF’s perspective.

5. **(5)** Requiring the regulator to verify costs based on detailed submissions and costing frameworks may not justify the effort, given that prolonged interruption events are expected to be infrequent.
While the act of submitting Strike Prices seems straightforward, our analysis suggests that ensuring that prices are efficient and meaningful representations of interruption cost is challenging, both for the regulator and the LRFs. The benefits may also be overstated, since: (a) during a contingency, PSO may not have the bandwidth to safeguard system security at least cost – hence nullifying the “ranking” benefit of Strike Prices, and (b) administrative caps are not desirable as LRFs have the natural incentive to bid at the cap – which means the PSO is better off compensating based on an administratively determined fixed amount.

In an ideal state, harnessing Strike Prices to determine LRF’s individual compensable amounts would be preferred. However, operational realities suggest that economic and administrative efficiency is hard to be achieved with this approach. As the next best option, the EMC proposes in the following section a system cost approach to determine the compensable amount.

**System Cost – MEP/MEGU**

Given the considerable challenges surrounding a Strike Price methodology, we examine compensation methodologies based on MEP/USEP (FERC Ruling) or MGU Variable Cost (South Korea) as alternatives. These methodologies determine compensable cost from a system perspective rather than from the individual LRF perspective and may not fully cover the cost incurred by the LRFs.

**Compensate based on MEP**

MEP(or USEP) compensation requires the market to start viewing LRFs as supply-side resources and hence should be offered equivalent treatment as generators. Following the FERC jurisdictions, this translates to receiving MEP/Nodal Price for the load curtailment rendered to the market, although the absence of energy bids means that LRFs would be a price taker. This is not the prevailing thinking in the market but is not far-fetched, given that DR resources are expected to participate in the impending Forward Capacity Market (“FCM”) through the supply curve.

An extension of the practice in FERC jurisdictions is to assume that the marginal generators at relevant network nodes would have to supply the incremental loads of the LRFs if the PSO had given clearance for load restoration. Following this logic, the value of continued curtailment to the market can be represented by the MEP required for the marginal generators to supply the LRFs’ restored load at the affected network nodes. As real-time markets are co-optimised in the SWEM, we cannot assume the MEP generated during the actual interruption to be similar to the hypothetical load restoration scenario. For accuracy, the EMC may have to establish for each affected period, a counterfactual MEP given the alternative scenario that the curtailed loads have been fully restored. A variant to using MEP would be to discount the locational impact of the LRFs and compensate LRFs based on a counterfactual USEP.

A survey of price data from past prolonged interruptions shows that there is low-to-no difference between the actual and counterfactual USEP. Thus for simplicity, the EMC proposes for this option to determine the compensable amount using the prevailing MEP or USEP using the formula: (MEP or USEP) x (Curtailed Capacity) x 0.5, which approximates the system avoided cost for each period.

In practice however, the MEP/USEP used to compute IL compensation may not fully reflect actual load curtailment value. During a high-risk/emergency operating state where LRFs are likely to

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20 From Feb 2018 to Feb 2020, there has been 2 instances of prolonged interruption: 29 Oct ’18 for 5 periods (1 period compensable), and 05 Jan ’19 for 14 periods (10 periods compensable). EMC focused the survey on the 05 Jan’19 activation, where counterfactual USEPs were established for each of the interrupted periods beyond 120-mins of activation. Across the 10 compensable periods: 4 periods had no price changes between the actual and counterfactual USEP; 4 periods had a price differential of less than $1/MWh; and 2 periods had a price differential of $4 and $5/MWh.
face prolonged interruption, prices produced by the MCE may not reflect the supply condition in the market as generators may have their MCE dispatch schedules overridden by the PSO, submit invalid offers, etc. Consequently, the default MEP may not reflect the marginal value of the last unit of resource needed to balance supply and demand at each network node. Lastly, dynamic supply conditions during contingency events may aggravate MEP fluctuation during prolonged interruptions. This will cause some unpredictability to LRFs in terms of the compensation amounts.

*Compensate based on MGU Variable Cost*

Alternatively, the PSO can exclude the locational impact of LRFs and assume that the prevailing marginal generating unit of the entire SWEM would have to supply the additional load if the LRFs had been given clearance for load restoration. Therefore, the system avoided cost for each period of prolonged interruption would be the (MGU Variable Cost) x (Curtailed Capacity) x 0.5. As there are limited number of peaking units in the market, we can expect greater consistency in MGU Variable Cost compared to the nodal MEP from period to period. Furthermore, LRFs can also have some sense of a GRF’s variable cost through Vesting Contract parameters – this provides some degree of predictability in terms of compensation amounts to LRFs.

While using a cost-based method will avoid the uncertainties surrounding the use of MEP/USEP, this method would require the PSO to identify the MGU operating at the time of prolonged contingency. The PSO would also need to extract generator cost information for computation of the compensation amount – the restrictions and efforts required to do so was not yet clear to the EMC prior to the industry consultation.

Following our analysis in section 3, Table 2 below employs an assessment matrix of the options considered.

### Table 2: Assessment Matrix

<table>
<thead>
<tr>
<th>Approach</th>
<th>System</th>
<th>Individual</th>
</tr>
</thead>
<tbody>
<tr>
<td>Options</td>
<td>(1) Compensate based on (a) MEP or (b) USEP</td>
<td>(2) Compensate based on MGU Variable Cost</td>
</tr>
<tr>
<td>Criteria</td>
<td>Yes – MEP/USEP approximates system avoided cost to the extent that the MCE produced dispatch schedule is not significantly overridden by the PSO</td>
<td>Yes – from value of service / system avoided cost point of view</td>
</tr>
<tr>
<td>Market Efficiency</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Degree of Predictability to LRFs</td>
<td>Low – may have fluctuations across periods</td>
<td>Mid – limited peaking units means more consistent Var Cost across periods; Var Cost can be benchmarked against Vesting Parameters</td>
</tr>
</tbody>
</table>
4. Consultation

The concept paper was published for consultation on 08 April 2020, and comments were received from 6 stakeholders, namely EMC Market Operations, Enel X, Keppel, Power System Operator, PacificLight Power, and Senoko.

Comments from PSO

1) To add onto the compensation consideration, it is given in the MR that the claimant shall specify the amount of the compensation sought. Hence, claimant must have and furnish all the necessary information for them to determine the compensation amount. This is in line with current practice whenever any MP submit a compensation claim.

2) In Option 3, the IL provider should account for the incremental cost of interruption in their reserve offers. The reserve offers is a good reflection of their strike price. It is not possible for PSO to verify the true cost their prolonged interruption. The compensation amount would be the difference between the reserve price and their reserve offers.

3) Option 1a/b using the USEP/ MEP is administratively simple as the prices are published but it is driven by cost of generation which could be different from a load perspective. Moreover, what if the USEP/ MEP is $0, does it mean the claimant pay the market? The methodology is not robust.

4) Option 2 using the MGU variable cost requires offer information to determine the marginal set which is not readily available for the claimant, unless EMC can provide the necessary information such as historical proxy formula. Again, like Option 1a/b, it is driven by the cost of generation which could be different from a load.

5) The consultation could also seek views from IL what is the marginal cost of LRFs.

6) Given that EMA is developing the FCM, PSO suggest that EMC should consider putting this rule change proposal on hold until the FCM’s rules have been firmed up.
EMC's Response

1) We note the claim process provided under the current market rules. We recognise it is difficult for LRFs to obtain generator information to furnish a compensation claim under Option 2. Should Option 2 be adopted, exceptions to the rule may need to be provided.

2) EMC has examined in detail, the suitability of using reserve offers as the basis of compensation. Aside from misalignments with the current compensation framework, EMC assesses that reserve offers represent the LRF's cost (or ‘premium’) to provide the PSO with a call option for load curtailment. The option premium is distinctly different from the actual direct cost of engineering a curtailment (i.e., strike price) – hence it is not a valid reflection of the strike price. EMC recognises the difficulties with verifying the 'true' cost of prolonged interruption, and thus recommended a system approach to impute the cost of interruption.

3) As compensation is requested by the claimant, the LRF has the prerogative not to pursue compensation if the USEP/MEP is found to be zero or negative. Barring network constraints, fault current and the likes, it is highly improbable for the USEP/MEP to be zero or negative during a high-risk/emergency operating state where an IL interruption is triggered. Zero or negative USEP/MEP also signifies a generation supply surplus, hence signalling higher market valuation for load restoration than continued curtailment.

4) We note PSO’s comment that as part of Option 2, it is difficult to determine the MGU and associated generation costs that could have been incurred.

5) Indicative info from LRFs are a good to have. However, given the practical challenges with verifying an LRF’s individual marginal costs, more ‘palatable’ cost amounts do not necessarily make a stronger case for Option 3.

6) Currently, EMC is unsure how FCM developments will impact the proposed compensation guidelines. EMC thinks there is value to enact rule changes on IL compensation to facilitate the compensation to ILs for instances of prolonged interruption till the FCM delivery year in 2023.

Comments from EMC Market Operations

1) As the market operator, EMC MO generally support the need to establish an appropriate compensation mechanism for LRFs facing prolonged interruption beyond 120-mins after contingency reserve activation. Besides the economic efficiency and fairness et al, operational feasibility, efficiency and cost effectiveness to the market is of paramount importance particularly in view of low frequency of such compensations.

2) Proposal (1a) to use the prevailing MEP has inherent challenges in determining the relevant marginal GRF due to the MCE co-optimization. It becomes even more ambiguous when there are price separations due to the transmission congestion. The market rules allowing the aggregation of physical loads from different locations within a load zone to a registered LRF adds another level of complications if the price separation occurs within the load zone.

3) Proposal 2 to use the MGU Variable Cost may have operational challenges to the PSO in determining the relevant MGU during the prolonged contingency but as the proposal says, it is not yet clear to EMC.

4) With this in mind, EMC MO supports 1(b) of a better-balanced approach which proposes to apply the prevailing USEP to determine the compensation amount.
**EMC’s Response**

1) EMC Market Administration agrees with the assessment criteria laid out by EMC MO.

2) As there are no specific Market Network Nodes assigned to an LRF, we agree that it is challenging to determining the relevant MEP for Option 1a.

3) PSO has highlighted that it is difficult for both the claimant and the PSO to determine the MGU and associated generation costs that could have been incurred.

4) We note MO’s preference to base compensation on USEP, given the foreseeable challenges with operationalising the other options.

**Comments from Senoko**

1) 2.1 Proposal “PSO may require LRFs to be interrupted beyond 120-mins to safeguard system security”. As per “EMC/RCP/107/2019/356 “, a hard limit of 120 mins should be set for PSO to curtail energy consumption for ILs. 120 mins provides ample time for GRFs to revise their bids in order to meet system requirements outside gate-closure. A simple average taken over the past year showed an average Contingency reserve participation from ILs of 0.83% of total Contingency requirements. Using 600MW as our benchmark Contingency Reserve requirement, 0.83% equates to roughly 4.98MW. We are in a view that the bid revisions from GRFs will be more than enough to cover the increase in energy consumption from ILs.

2) 3.4.2 Applicability in the SWEM “impending Forward Capacity Market (“FCM”) through the supply curve”. Going through changes to the compensation framework now could prove to be inefficient. Upon the implementation of FCM, changes made now could become obsolete or irrelevant. Hence, we propose that this framework review is to be deferred till the implementation of FCM.

**EMC’s Response**

1) EMC agrees with Senoko’s analysis. Ideally, EMC will prefer to specify a 120-min maximum duration for the IL product, beyond which the LRF is relieved of its product obligations. Should the PSO determine the need for further curtailment, this should be issued as a separate instruction that is distinct from arrangements under the IL scheme. However, in the concept paper EMC/RCP/105/2018/CP74, EMC assessed that the PSO requires the flexibility to interrupt LRFs beyond 120 minutes to manage system security.

2) Currently, EMC is unsure how FCM developments will impact the proposed compensation guidelines. EMC thinks there is value to enact rule changes on IL compensation to facilitate IL compensation up till the FCM delivery year in 2023. For the avoidance of doubt, EMC referenced the supply-side participation model for capacity DR capacity resources in the PJM/NYISO only as a supporting principle for Option 1. Option 1 could be adopted based on other merits and is not disqualified because of the implementation status of the FCM.

**Comments from PacificLight Power**
1) Any means of compensation does not solve the problem faced by interruptible load service providers. We have been advocating a review of the constraint violation penalty principles in order to address the root cause of prolonged interruption. The frequency of contingency shortfall has gone up after the introduction of constraint violation penalty (CVP). The problem goes beyond fair compensation for load registered facilities. We should ensure security of system by procuring sufficient reserve in the first place through an urgent review of CVP, which has been listed top in EMC’s annual work plan for 2019-2020 and 2020-2021.

EMC’s Response

1) EMC will be reviewing the CVP as part of the 20/21 workplan. EMC would also highlight that circumstances not related to CVP also contribute to the need for prolonged IL interruption by the PSO.

Comments from Enel X’s

1) We view compensation methodologies determined from a system perspective to be straightforward, however, it does not fully cover the costs incurred by the LRFs. It is rightfully pointed out in Appendix A that different methods of LRFs participation face significantly different marginal cost curve, which generally tend to increase as the interruption duration is prolonged. With no cap in the interruption duration, the LRFs would face costs significantly higher than the MEP/USEP. This is a strong pain point in encouraging IL participation. Given that, our view is still that participation in an interruption beyond the 2-hour mark be an optional activity that is compensated using one of the methods EMC proposes. Else the risk of uncapped interruption duration will significantly restrict the LRFs available to participate in the market, which results in higher procurement costs for EMC than if more LRFs were participating.

2) Among both Option (1) and (2), we view Option (1) as a fairer methodology as it is more transparent and relatable to the end users. While it makes sense to base the compensation on LRFs’ MEPs, it may pose operational challenges if LRFs’ loads are aggregated and offered into SWEM by Load Zone. By this reasoning, compensation based on USEP is more straightforward. However, we think the counterfactual USEP would be more reflective of the prices. EMC survey of price data on 5 January 2019 may be under-estimating the differences between actual and counterfactual USEP. The scheduled reserve from LRFs on 5 January 2019 is lesser than 27.5MW (total registered capacity), it is substantially lower than the maximum scheduled contingency reserve from LRFs at 30% of contingency reserve requirement. We propose EMC to look into the price differences at the maximum scheduled contingency reserve capacity for a more realistic consideration.

3) On Option (2), the MGU variable cost is non-transparent to the load facilities as PSO or generators would need to provide these variable costs, LRFs may see it as unfair and not relatable. If the MGU is determined based on MCE dispatch, which is determined through the offer stack, a high variable cost unit may offer lower than its variable cost to secure dispatch, vice versa. The resulting MGU would not be a fair point of reference.
4) Other costs that should be considered are the optionality for LRFs to curtail beyond 2 hours, and the risk of non-compliance to stay curtailed beyond 2 hours for an uncapped interruption duration. The non-optionality is not priced in to the proposed compensation methodology, which suggest LRFs would always be under-compensated. To overcome an uncapped interruption duration, LRFs would need to offer far lesser than its available loads to reduce the risk of non-compliance, resulting in inefficiency for the market in general.

5) Lastly, the proposed compensation methodology may favor some LRFs to the others. For instance, impacts on production plants are not as severe as impact on sites with high indemnity and liability to their customers if they are all subjected to the proposed compensation level. We suggest referencing the compensation on the Value of Loss Load as an equitable level of compensation. This would align with the concept and definition of VoLL as well as the financial penalty for IL service providers.

EMC’s Response

1) We appreciate Enel X’s views that an unspecified maximum duration limits LRF participation in the IL scheme.

2) Based on the current level of IL participation, the current analysis suggests low to no difference between the actual and counterfactual USEP. EMC will revisit the guidelines to determine the compensation rate should IL participation grow significantly.

3) EMC appreciates Enel X highlighting that the information is not transparent to LRF and there can be inaccuracies if the MGU is determined through the offer stack.

4) EMC notes that the concern on non-optionality premium only applies to Options 1 and 2 where compensation rates are based on the system benefit. Alternatively, LRFs can price the non-optionality for prolonged interruption (~10% of IL activations) into their reserve offers.

5) EMC acknowledges the shortcomings and trade-offs associated with the use of Options 1 and 2. Referencing compensation on the value of VoLL ($5,000/MWh) will not solve the issues posed by idiosyncratic cost, since the VoLL is an economy-wide average. Although using a system established price provides relief for LRFs to different degrees, it is still useful as an objective measure to capture the system scarcity value for the LRF. Indeed, when the supply situation warrants it, system prices can rise to levels equal to the VoLL.

Comments from Keppel

1) Keppel recommends that before each trading period of prolonged IL activation, PSO should request if IL providers can continue to provide its service to system security while providing compensation without risking IL participant’s contractual obligations. Loads supporting critical infrastructure and key resources cannot sustain indefinite interruption.

EMC’s Response

1) Ideally, EMC will prefer to specify a 120-min maximum duration for the IL product, beyond which the LRF is relieved of its product obligations. Should the PSO determine the need
for further curtailment, this should be issued as a separate instruction that is distinct from arrangements under the IL scheme. However, in the concept paper EMC/RCP/105/2018/CP74, EMC assessed that the PSO requires the flexibility to interrupt LRFs beyond 120 minutes to manage system security.

5. Conclusion and Recommendations

In conclusion, we consider that Option 1(b) is, on balance, the preferred approach for the compensation of LRFs that have been interrupted beyond 120 minutes after a contingency reserve activation. This is based on the following logic: -

(1) In theory, the approach in Option 3 best addresses the reality that interruption costs differ across demand-side participants and are idiosyncratic to each LRF. However, through industry consultation, demand-side participants and the PSO agreed that it is operationally difficult to ascertain and verify the “true” cost of interruption. Requiring LRFs to submit guaranteed energy strike prices poses its own set of challenges as LRFs have the natural incentive to overbid. Conversely, while administrative caps will help to restrain bids, a reasonable cost cap is not easy to determine and justify. As next best options, system benefit approaches were discussed to impute an objective measure for the scarcity value of the LRF’s prolonged interruption.

(2) Option 2 assumes that the prevailing marginal generating unit of the entire SWEM would supply the additional load upon LRF restoration, and hence the cost of interruption is imputed by the variable cost of the MGU. Industry comments showed that the identity of the MGU and its associated variable cost information is not easily available to the PSO or the EMC. As the initiator of the compensation claim process, an LRF also does not have access to the MGU cost information for proposing the compensable amount. Consequently, Option 2 is not a workable option.

(3) Option 1(a) which compensates LRF based on the locational energy price, ideally accounts for the value to the system from the prolonged interruption. However, this is not workable as LRFs are currently not assigned to any Market Network Node in the MCE. There is therefore no obvious singular MEP to base compensation on. It is an operational challenge for an LRF to identify the appropriate locational energy price. On the other hand, Option 1(b) bases compensation on the prevailing USEP, which is available to the public and is easily accessible for LRFs requesting compensation. While the USEP might not be fully reflective of the locational value, EMC thinks it provides a fair indication most of the time and is a more objective metric than individualised energy strike prices. Lastly, Option 1(b) satisfies a majority of the design considerations and is simple to operationalise.

6. Decision at the 116th RCP Meeting

The concept paper was discussed at the 116th RCP meeting and the panel by majority vote

(1) Supported the adoption of Option 1, in principle: to base the IL compensation amount calculation on the prevailing USEP/MEP, or a variant of it; and

(2) Tasked the EMC to study Option 1 in further detail and draft the compensation guidelines and necessary market rule modifications to refer to the guidelines should LRFs request for compensation.
The following Panel members supported the principles for and approaches to compensate an LRF affected by prolonged interruption of more than 120 minutes:

1. Mr. Soh Yap Choon (Representative of the PSO)
2. Mr. Henry Gan (Representative of EMC)
3. Mr. Teo Chin Hau (Representative of Generation Licensee)
4. Mr. Matthew Yeo (Representative of Wholesale Electricity Trader)
5. Mr. Sean Chan (Representative of Retail Electricity Licensee)
6. Mr. Senthil Kumar (Representative of the Retail Electricity Licensee)
7. Dr. Toh Mun Heng (Representative of Consumers of Electricity in Singapore)
8. Mr. Fong Yeng Keong (Representative of Consumers of Electricity in Singapore)
9. Ms. Ho Yin Shan (Representative of the Market Support Services Licensee)
10. Ms. Carol Tan (Representative of Transmission Licensee)
11. Mr. Tan Chian Khong (Person experienced in Financial Matters in Singapore)

The following Panel member did not support:

1. Mr. Sim Meng Khuan (Representative of the Retail Electricity Licensee)

The following Panel member abstained from voting:

1. Mr. Tony Tan (Representative of Generation Licensee)
2. Mr. Marcus Tan (Representative of Generation Licensee)

7 Follow-ups to the 116th RCP Meeting

As tasked by RCP, the EMC further studied Option 1 and assessed the USEP to be the most suitable ‘reference price’ for determining the compensation amount.

The proposed ‘reference price’ should be able to capture the benefit of prolonged interruption to the power system. The benefit to the system can be proxied by the cost avoided by the system (or “system avoided cost”) due to the prolonged interruption – since the system would have incurred additional cost to supply incremental load if the affected LRFs had restored their consumption instead.

Following the above argument, the compensation rate should reflect the marginal system avoided cost – the system cost savings due to an additional MW of IL capacity providing continued curtailment. This is approximated by the System Marginal Price (“SMP”) which captures the additional cost needed for the power system to supply an additional MW of energy.

The Uniform Singapore Energy Price (“USEP”) is the Singapore Wholesale Electricity Market (“SWEM”)’s equivalent of the SMP. Due to co-optimisation across the Energy and Ancillary Services Markets, the USEP captures the marginal cost at the power system level, decomposed into:

a) The specific generation cost needed to supply an additional MW of energy; and

b) The associated reserve/regulation replacement cost (if any, as determined by the Market Clearing Engine) that generators/loads would have to bear.

As a fair and transparent indicator of the marginal system avoided cost, the USEP serves as an easily accessible reference price for MPs and the PSO alike to determine the compensation rate.
for affected LRFs. By taking the weighted average of nodal prices across all offtake nodes in the system, the USEP also bypasses the need for the MP and the PSO to identify and extract unique nodal prices for each LRF when computing the compensation amounts.

Consequently, the EMC proposes the use of the prevailing USEP as the reference price for computing compensation amounts for LRFs across affected periods. The draft guidelines and computation formula based on the usage of USEP as reference price is found in Appendix C.

8 Decision at the 117th RCP Meeting

The follow-ups to the 116th RCP meeting were discussed at the 117th RCP meeting and the panel by majority vote

(1) Endorsed the compensation guideline for LRFs facing prolonged interruption, as set out in Appendix C; and

(2) Tasked EMC to draft modification to the Market Rules in order for the compensation guideline to be used as a reference for the calculation of compensation amount.

The following Panel members supported the EMC’s recommendation:

1. Mr. Henry Gan (Representative of EMC)
2. Mr. Marcus Tan (Representative of Generation Licensee)
3. Mr. Teo Chin Hau (Representative of Generation Licensee)
4. Mr. Tony Tan (Representative of Generation Licensee)
5. Ms. Carol Tan (Representative of Transmission Licensee)
6. Mr. Sean Chan (Representative of Retail Electricity Licensee)
7. Dr. Toh Mun Heng (Representative of Consumers of Electricity in Singapore)
8. Mr. YK Fong (Representative of Consumers of Electricity in Singapore)
9. Mr. Tan Chian Khong (Person experienced in financial matters in Singapore)

The following RCP member abstained from voting:

1. Mr. Soh Yap Choon (Representative of the PSO)
2. Mr. Sim Meng Khuan (Representative of Retail Electricity Licensee)
3. Mr. Matthew Yeo (Representative of Wholesale Electricity Trader)
4. Ms. Ho Yin Shan (Representative of the market support services licensee)
Appendix A: Marginal Costs of LRFs

At specified heat rates, GRFs incur constant marginal cost as they burn fuel at a consistent rate to generate a constant level of power across multiple periods. Unlike GRFs, LRFs do not burn fuel to generate capacity curtailment (i.e., a “megawatt” of energy). Instead, LRFs employ various methods to enable load facilities to reduce the amount of energy drawn from the grid.

This appendix lists out 3 common methods the load facilities generally use to participate in IL schemes across jurisdictions. We explain through these examples why LRFs facing interruption beyond a single period face varying marginal cost across the multi-period interrupted duration, even though the curtailed capacity remains the same.

<table>
<thead>
<tr>
<th>Method to Participate in IL Scheme</th>
<th>Marginal Cost Function</th>
</tr>
</thead>
<tbody>
<tr>
<td><em>During a contingency event…</em></td>
<td><em>During a multi-period load interruption…</em></td>
</tr>
<tr>
<td><strong>Back-up Generators</strong></td>
<td>Back-up generators tend to be diesel-run, and load facility owners have limited stockpile of fuel. This means that marginal cost is theoretically constant up to the period where fuel stocks are exhausted, and the cost of interruption spikes as critical processes are interrupted/threatened (e.g., emergency operating theatre, life-support systems, process manufacturing crucibles etc.). While fuel is burnt at a constant rate, LRFs may wish to incorporate a risk-premium to each successive period of curtailment to factor in the risk of exhausting their fuel supplies. This means that marginal cost could in fact be increasing with time.</td>
</tr>
<tr>
<td>LRFs are islanded from the grid and operate embedded/captive generation facilities to supply the site load without interruption.</td>
<td></td>
</tr>
<tr>
<td>LRFs of this nature can be curtailed for long durations (e.g., 10-hrs).</td>
<td></td>
</tr>
<tr>
<td><strong>Chiller Systems with Thermal Storage (Ice Banks)</strong></td>
<td>Anecdotally, ice banks have the cold energy capacity to sustain operations for 4- to 6-hours. At the basic level, marginal cost should capture the cost of charging ice banks, which are broadly constant given that charging tends to happen during production off-peak periods (00:00 to 06:00). A more robust perspective would be to recognise that ice banks are not installed primarily to participate in the IL scheme, and hence marginal cost should incorporate the forgone incremental cost-savings that could have been obtained in subsequent periods using the same MW of</td>
</tr>
<tr>
<td>LRFs curtail their site load supplied from the grid by varying the operations of their chiller plants. They do so by running chiller systems at lower capacities* and instead, chill the cooling medium to the required temperature by using cold energy from the ice banks.</td>
<td></td>
</tr>
<tr>
<td>Ice banks are charged during off-peak periods by running the chillers at higher capacities than required by the site load.</td>
<td></td>
</tr>
</tbody>
</table>
*This entails tuning down chiller compressors, pumps, cooling towers, etc. and instead,

Ice banks are also a regular component of district cooling systems ("DCS") to act as cooling redundancy for DCS clients who have temperature sensitive manufacturing processes (e.g., wafer fabs, biologics, chemicals etc.).

**Industrial/Commercial Consumers that have Interruptible Processes**

Commercial buildings may curtail non-essential lighting or air-conditioning operations to comply with IL activation requirements.

Industrial facilities may halt certain procedures to provide load curtailment when called-upon. Affected procedures are likely to be part of a wider process train(s) or assembly line(s). This is likely to be the case for manufacturing segments with spare capacity (e.g., compressed air with storage tanks), or discrete manufacturing segments that can be rescheduled.

chilling capacity for core functions like optimising chiller operations and voluntary curtailment in response to higher prices, etc. These forgone costs would vary depending on the timing of IL activation.

When cold energy is exhausted, critical processes that are dependent on chilled water are threatened and this may cause marginal cost to spike.

**Commercial Buildings.**

**Non-essential lighting:** Curtailment may incur a fairly constant marginal cost. However, quantum of load curtailment may not be sufficient for min. participation and would need to be paired with other load reductions.

**Air-conditioning operators:** With each period of curtailment, the ambient heat load increases, leading to increasing occupant discomfort. Marginal cost faced by building operator could be measured in terms of occupant discomfort/displeasure and to a larger extent, worker productivity. This is expected to increase with each successive period of interruption.

**Industrial Facilities.**

Manufacturers seek to maximise gains from their factors of production and are expected to run manufacturing lines around the clock, when possible. Halted segments will not impact manufacturer’s bottom line, as long as it does not become the bottleneck in the process train/assembly line, after which marginal cost is expected to spike. Similar to previous examples, the manufacturer may incorporate a risk-premium to factor for decreasing spare capacity, or increasing approach to bottlenecking.
## Appendix B: IL Products in Different Jurisdictions

<table>
<thead>
<tr>
<th>Programme</th>
<th>Product Specifications</th>
<th>Payment</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>SWEM</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Interruptible Load Scheme – Contingency Reserve (Real-time Ancillary Service)</td>
<td><strong>Lead Time:</strong> 10-mins</td>
<td><strong>Marginal Clearing Price</strong></td>
</tr>
<tr>
<td></td>
<td><strong>Max Duration:</strong> not-specified, soft-limit of 120-mins, beyond which load resource can seek compensation from the PSO</td>
<td></td>
</tr>
<tr>
<td><strong>PJM</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Synchronised Reserve (Real-time Ancillary Service)</td>
<td><strong>Lead Time:</strong> 10-mins</td>
<td><strong>Marginal Clearing Price</strong></td>
</tr>
<tr>
<td></td>
<td><strong>Max Duration:</strong> 30-mins</td>
<td></td>
</tr>
<tr>
<td>Emergency Demand Response (Capacity)</td>
<td><strong>Lead Time:</strong> 30-mins (Default); 60, 120-mins (Subject to PJM approval)</td>
<td><strong>Availability Payment</strong> – capacity payments determined based on PJM’s Reliability Pricing Model (&quot;RPM&quot;)</td>
</tr>
<tr>
<td></td>
<td><strong>Max Duration:</strong> 10 to 15-hrs, depending on seasonality/time-of-year</td>
<td><strong>Utilisation Payment</strong> – higher of Locational Marginal Price (&quot;LMP&quot;) or Emergency Strike Price</td>
</tr>
<tr>
<td></td>
<td><strong>Emergency Strike Price</strong> to be proposed by load resource is subject to administrative cap and cannot be changed during delivery year</td>
<td><strong>Max Strike Price</strong> based on lead time: default is 30-mins: USD1,849/MWh; if approved by PJM, 60-mins: USD1,425/MWh, 120-mins: USD1,100/MWh</td>
</tr>
</tbody>
</table>

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### NYISO

<table>
<thead>
<tr>
<th>Demand Side Ancillary Service</th>
<th><strong>Lead Time</strong>: 4-secs or 10-mins</th>
<th>Marginal Clearing Price</th>
</tr>
</thead>
<tbody>
<tr>
<td>(Real-time Ancillary Service)</td>
<td><strong>Max Duration</strong>: 10-mins or 30-mins</td>
<td></td>
</tr>
</tbody>
</table>

- **Installed Capacity – Special Case Resource (“ICAP-SCR”) (Capacity):**
  - **Lead Time**: 2-hrs (ICAP-SCR); 2-hrs or day-ahead advisories
  - **Max Duration**: 4-hrs
  - **Minimum Payment Nomination** to be proposed by load resource is subject to administrative cap and can be different across each auction month

- **Availability Payment** – capacity payments determined based on sales made through ICAP auctions or bilateral contracts

- **Utilisation Payment** – higher of Locational Based Marginal Price (“LBMP”) or Minimum Payment Nomination (i.e., Strike Price)

- **Cap on Minimum Payment Nomination**: USD500/MWh

### South Korea - KPX

<table>
<thead>
<tr>
<th>Emergency Response Programme (Capacity)</th>
<th><strong>Lead Time</strong>: 1-hr</th>
<th>Availability Payment – calculated similar to the capacity price for generators</th>
</tr>
</thead>
</table>

- **Max Duration**: 1-hr for SMEs, 1- to 4-hrs for Normal Resources. Activation is limited to 60-hrs per year

- **Utilisation Payment** – determined based on highest variable generation cost at point during activation. This is based on the thinking that the resources assume a role to substitute for high-cost generators

### Ontario - IESO

<table>
<thead>
<tr>
<th>Hour Demand Response (&quot;HDR&quot;) for Emergency Operating State Control</th>
<th><strong>Lead Time</strong>: Stand-by warning provided day-ahead or day-of (by 8 a.m.), dispatch notice provided approximately 2 hour prior to event start time</th>
<th>Availability Payment – calculated similar to the capacity price for generators</th>
</tr>
</thead>
</table>

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| Action ("EOSCA") Activation (Capacity) | **Max Duration:** 4-hrs | **Utilisation Payment** – bid-based payment: (Bid – HOEP), where “HOEP” is the Hourly Ontario Electricity Price, and “Bid” is the Energy Bid supplied by the DR resource. |
Appendix C: Compensation Guidelines for LRFs that experienced Prolonged Interruption

Under Chapter 5, Section 9.3.7 of the Market Rules, Load Registered Facilities ("LRFs") providing reserves under the IL scheme may request for compensation from the PSO if: 

1. The LRF responded automatically or to the PSO’s instructions for reserve activation during a contingency event;
2. The PSO only issued a load restoration notice more than 120 minutes after the point the LRF was activated for reserves; and
3. The LRF restored its load only upon the load restoration notice.

LRFs that fulfill the above are deemed as “having experienced prolonged interruption”. These LRFs are deemed to have provided more reserves than they are scheduled for. Consequently, the LRFs should be compensated for energy curtailment provided beyond 120 minutes from the point of activation.

The compensation calculation formula with respect to an LRF is defined as: 

\[ \text{Comp}_n = Q_n \cdot \sum_i (j_i/60 \times \text{USEP}_i) \]

Where:

- \( Q_n \) is \( LRF_n \)'s reserve scheduled quantity for the period which IL is activated, or any other curtailed load quantity (MW) as instructed by the PSO.
- \( \text{USEP}_i \) is the Uniform Singapore Energy Price for the period \( i \).
- \( j_i \) is the number of minutes the \( LRF_n \) is curtailed for within the period.

**Worked Example**

On 5th Jan 2019, the PSO issued a contingency reserve activation instruction 12 minutes into period 31 (15:12). \( LRF_1 \) responded to the PSO’s activation instruction by 15:22 (within 10-min notification lead time) by curtailing its load consumption by 5 MW. The PSO gave the load restoration notice at 22:08 (period 45) and \( LRF_1 \) complied. The worked example is illustrated in the table below.

<table>
<thead>
<tr>
<th>Period</th>
<th>USEP ($/MWh)</th>
<th>Remarks</th>
<th>Minutes entitled for compensation</th>
<th>Compensation Amount ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>31</td>
<td>115.41</td>
<td>Activation at 15:12</td>
<td>n/a</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Actual curtailment by 15:22</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

24 For more details on this market rule provision, please refer to Paper No. EMC/RCP/107/2019/356: Restoration of Load Registered Facilities Activated to Provide Reserve.

25 For more details on the EMC’s analysis and the RCP’s decision, please refer to Paper No. EMC/RCP/116/2020/CP81.
<p>| | | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>32</td>
<td>662.09</td>
<td>n/a</td>
<td></td>
</tr>
<tr>
<td>33</td>
<td>485.70</td>
<td>n/a</td>
<td></td>
</tr>
<tr>
<td>34</td>
<td>427.24</td>
<td>n/a</td>
<td></td>
</tr>
<tr>
<td>35</td>
<td>290.11</td>
<td>120-min mark passed at 17:22 (t+22)</td>
<td>8</td>
</tr>
<tr>
<td>36</td>
<td>283.48</td>
<td></td>
<td>30</td>
</tr>
<tr>
<td>37</td>
<td>290.02</td>
<td></td>
<td>30</td>
</tr>
<tr>
<td>38</td>
<td>310.45</td>
<td></td>
<td>30</td>
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<tr>
<td>39</td>
<td>473.56</td>
<td></td>
<td>30</td>
</tr>
<tr>
<td>40</td>
<td>290.16</td>
<td></td>
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<tr>
<td>41</td>
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<tr>
<td>42</td>
<td>277.04</td>
<td></td>
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</tr>
<tr>
<td>43</td>
<td>273.33</td>
<td></td>
<td>30</td>
</tr>
<tr>
<td>44</td>
<td>263.32</td>
<td></td>
<td>30</td>
</tr>
<tr>
<td>45</td>
<td>107.94</td>
<td>Load restoration notice at 22:08 (t+8)</td>
<td>8</td>
</tr>
</tbody>
</table>

**Total Compensation Amount:** $7087.62

**Qualified periods for compensation:** period 35 (t+22) till period 45 (t+8). $Q_f = 5$ MW

∴ the compensation amount based on this reference price methodology is $7087.62.

Should the MP representing $LRF_f$ wish to request for compensation from the PSO, the MP will have to propose the compensation amount with backing calculations for the PSO’s consideration.