This paper proposes modifications to the Market Rules to effect RCP’s decision at the 118th RCP meeting on providing real-time estimates of the Reserve Responsibility Share (RRS) for each Generation Registered Facility (GRF).

Specifically, the RCP by majority vote supported the following:

a. Using the existing RRS calculation methodology to calculate forecasted RRS;

b. Calculating forecasted RRS for Real-Time Schedule (RTS), Short Term Schedule (STS) and Pre-dispatch Schedule (PDS); and

c. Providing forecasted RRS to the relevant owner-MPs only

EMC is proposing 2 options for the RCP to consider on the implementation approach for providing real-time estimates of RRS for each GRF.

Option 1: To implement the proposal as a value-added service to MPs

Option 2: To implement the proposal as a market rule obligation on EMC

The differences between the 2 options relate to cost, implementation time and expected service standard levels.

Although the release of forecasted RRS will enhance market transparency, EMC assessed that the cost of Option 2 would be much higher than Option 1. There were also a significant number of feedbacks received from the industry preferring implementing the project as a value-added service to MPs (Option 1)

Therefore, EMC recommend RCP to support the following:

- Implement the forecasted RRS as a value-added service to MPs
• On a best effort basis, for EMC to release the information to relevant owner-MPs within two hours of releasing the corresponding forecast schedules
• No Auto-recovery or Re-run of forecasted RRS due to system issues

At the 123rd RCP meeting held on 12 May 2021, the RCP by majority vote supported EMC’s recommendations.
1. **Introduction**

This rule change proposal seeks to propose rule modifications of the Singapore Electricity Market Rules (Market Rules) on the provision of real-time estimates of the Reserve Responsibility Share (RRS) for each Generation Registered Facility (GRF), which was supported by RCP at the 118th RCP meeting.

2. **Background**

This rule change proposal follows CP84 which analysed the benefits and costs of providing forecasted RRS to NEMS market participants.

2.1 **What is Reserve Responsibility Share (RRS)?**

The RRS is a parameter to allocate reserve costs\(^1\) that is calculated with a Modified Runway Model. This parameter is calculated from 2 inputs: (1) a GRF’s energy dispatch schedule and (2) a GRF’s standing probability of failure\(^2\) (SPF). In general, a GRF that has a higher scheduled energy quantity and a higher SPF will have a higher RRS and thereby allocated a higher proportion of reserve costs.

2.2 **Schedules Published by EMC**

EMC produces the following dispatch and price schedules in accordance with the Market Rules. Please refer to Table 1 below.

<table>
<thead>
<tr>
<th>Type of Schedule</th>
<th>Frequency of publication</th>
<th>Coverage</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Real Time Schedule (RTS)</td>
<td>Every Period</td>
<td>Upcoming period T</td>
<td>Binding dispatch schedule</td>
</tr>
<tr>
<td>Also known as</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Dispatch Run (DPR)</td>
<td>T-30 seconds</td>
<td>Upcoming periods from T+1 to T+12 excluding upcoming period T which is covered under RTS</td>
<td>Forecast Schedule</td>
</tr>
<tr>
<td>Short Term Schedule (STS)</td>
<td>Every Period</td>
<td>Covers at least 24 periods and not more than 72 periods</td>
<td>Forecast Schedule</td>
</tr>
<tr>
<td>Pre-Dispatch Schedule (PDS)</td>
<td>Every 2 hours</td>
<td></td>
<td>Forecast Schedule</td>
</tr>
<tr>
<td>Market Outlook Scenario (MOS)</td>
<td>Every Day</td>
<td>All periods from the start of the next day for 6 consecutive days.</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Published by</th>
<th>T+5 Mins</th>
<th>15 Mins before each 2-hour block, starting from 0000 hrs</th>
<th>9am of each day</th>
</tr>
</thead>
</table>

\(^1\) Only applicable to GRFs that are scheduled for more than 10MW of energy.

\(^2\) Standing Probability of Failure (SPF) is a measurement of a GRF’s reliability. In general, the higher the SPF, the less reliable the GRF as the probability of the GRF experiencing a forced outage is higher. Under the Market Rules, EMC is tasked to maintain a register of SPF for all GRFs and provide this information to all MPs and the Market Support Services Licensee (MSSL), Market Rules, Appendix 7A, A.7.
2.3 Current Market Rule Obligations for Publishing of RRS

Under the current Market Rules, EMC is obliged to calculate the RRS based on an approved methodology after each dispatch period. This calculated RRS will then be used in the allocation of reserve costs for settlement. This RRS is only made available to the Market Participant (MP) that owns the GRF (owner-MPs).

EMC is currently not required to forecast RRS. Hence, this paper will examine the costs and benefits associated with providing forecasted RRS, the methodology for calculating forecasted RRS and the appropriate recipients of forecasted RRS.

3. Analysis

In this section, we analyse the costs and benefits of calculating/publishing forecasted RRS in the various dispatch schedules.

3.1 Benefits of Information Disclosure

In standard economic literature, it is generally accepted that availability of information is vital for the efficient operation of markets. For a general discussion on the benefits of information disclosure and transparency, please refer to RC355: Publication of Offer Data.

In this paper, we concentrate on the potential benefits to MPs and the industry of making forecasted RRS available. In general, publishing forecasted RRS may yield the following benefits:

At the Individual MP Level

Forecasted RRS can give a MP an indication on how much reserve costs will be allocated to its GRF or a portfolio of GRFs based on their SPF and forecast schedule. This information will allow MPs to optimise their offers between energy and reserve products so that they are able to act to maximise net revenue from the market and minimise the risks associated with their bidding strategies.

For example, if the RRS for an upcoming dispatch period indicates that a GRF will be allocated a large share of the reserve costs, the GRF can reduce its energy offer (either physically removing the offers or economically removing it by pricing offers higher) to reduce its scheduled quantity, thereby reducing reserve costs. Alternatively, the GRF can offer more into the reserve products to increase its overall net revenue for the period.

At the Industry Level

Information asymmetry can create competitive disadvantage to smaller MPs. Larger MPs with significant share of supply have a natural information advantage over smaller MPs. This is simply by virtue of knowing their own production and costs, which form a large proportion of the market. Disclosure of Forecasted RRS may reduce this information asymmetry.

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3 Market Rules, Chapter 7, Section 2.2.4: “The EMC shall, following each dispatch period, determine the reserve responsibility share (RRS) for each GRF for the settlement interval corresponding to that dispatch period.”

4 Market Rules, Appendix 7A: Calculation of Reserve Responsibility Shares

5 RRS was originally allocated based on metered IEQ. This may partially explain why the RRS information is found under Market Rules, Chapter 7: Settlement. Please refer to RC244: Allocation of Reserve Costs for more information.

6 Please refer to RC355: Publication of Offer Data for a summary of the benefits and costs to in general.
For example, smaller MPs can use the forecasted RRS information of the larger MPs to enhance their own bidding strategies because the larger MPs’ energy dispatch levels can be inferred from their RRS.

Similarly, larger MPs can use the forecasted RRS of smaller MPs in the same way. And by being larger and typically controlling more units, larger MPs would potentially have more options in their bidding strategies. However, this can be a double-edged sword. The unintended consequence may be that of enhancing structural advantages that larger MPs may already have over the smaller MPs, and this is more so if the industry structure is not competitive.

Therefore, the benefits of the publication of the forecasted RRS information at the industry level is dependent on the competitiveness of the market structure at a given point in time. The more competitive the market structure, the stronger the benefits. In a non-competitive setting, there is risk of enhancing the structural advantages of larger MPs.

3.2 Costs of Information Disclosure

The disclosure of market-relevant information normally improves market outcomes. In some cases, however, it may instead facilitate and/or encourage anti-competitive behaviour. Anti-competitive behaviour such as unilateral exercise of market power or collusion between MPs can result in a variety of harm, such as high prices to consumers, productive inefficiency and dynamic inefficiency.

In the Singapore Wholesale Electricity Market (SWEM), factors such as high seller concentration, product homogeneity, inelastic demand and stability of costs can increase the propensity for anti-competitive behaviour. It is therefore important to assess the structural competitiveness of the SWEM. This can be done by looking at a variety of indices. The indices most used by market monitors and authorities around the world are the Herfindahl-Hirschman Index (HHI) and the Residual Supplier Index (RSI). In this paper, we use both the HHI and the RSI as measurements of the competitiveness of the SWEM. Please refer to Annex A for details on index methodologies and the resultant analysis.

The HHI is typically used to measure the competitiveness of a market structure in the long run. Based on HHI analysis, the SWEM is deemed to be more competitive today compared to January 2013. From a ‘highly concentrated market’, the SWEM has become ‘moderately concentrated market’ since January 2017.

The RSI is typically used to measure the periodic competitiveness of a market. Our RSI analysis suggests that ‘transient’ market power remains in the SWEM. Based on recent data covering 01 Jan 2019 to 31 May 2020, pivotal suppliers were present in 33% of dispatch periods, although the distribution of pivotal periods in the 2 years are slightly different. Please refer to Annex A for detailed analysis.

We assess that the ability to exercise pricing power by pivotal MPs remains possible at certain times. Hence, further disclosure of information that can enhance the abilities of pivotal MPs to exercise market power should be considered carefully.

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7 For a description of the various indices, please refer to the following paper, Discussion Paper No. 14-048: Screening Instruments for Monitoring Market Power in Wholesale Electricity Markets – Lessons from Applications in Germany by the Centre for European Economic Research, July 2014. Link

8 ‘Transient’ market power is a term used by Frontier Economics in Review of Vesting Contract Regime for EMA in August 2016. It refers to one of the Australian Energy Market Commission (AEMC)’s final determination on market power. AEMC makes a temporal distinction between generators having transient pricing power/market power, ability to increase prices for short periods of time and substantial market power, ability to sustain pricing above the level that would prevail in a workably competitive market. Please refer to AEMC, Final Rule Determination, Potential Generator Market Power in the NEM, 26 April 2013, p.19. Link
4. **Practical considerations for publishing forecasted RRS**

The potential benefits of improved information transparency should also be weighed against financial and other costs associated with the following:

- Choice of methodology for calculating forecasted RRS
- Range of dispatch schedules to provide forecasted RRS for
- Provision of forecasted RRS to all MPs or only to the owner-MPs

### 4.1 Methodology to Calculate Forecasted RRS

As the methodology for calculating RRS is well documented in the Market Rules, we assess that there is no need to create another methodology to calculate forecasted RRS.

### 4.2 Range of Dispatch Schedules to Calculate Forecasted RRS for Implementation and Recurring Costs

If the forecasted RRS is to be calculated/published for the full range of dispatch schedules, i.e. RTS, STS, PDS, and MOS, implementation and recurring costs would be significant. Itemised cost estimates were provided jointly by EMC’s Technology Team and Market Operations Team in Table 2 below.

**Table 2: Estimated Implementation Costs and Time for Various Schedules**

<table>
<thead>
<tr>
<th>Cost Estimates</th>
<th>Option (1) RTS + STS</th>
<th>Option (2) PDS + Option (1)</th>
<th>Option (3) MOS + Option (2)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Analysis and Requirement Gathering/Sharing</td>
<td>$9,984</td>
<td>$9,984</td>
<td>$9,984</td>
</tr>
<tr>
<td>2. Development / Testing / Deployment Documentation</td>
<td>$77,875</td>
<td>$85,017.50</td>
<td>$92,160</td>
</tr>
<tr>
<td>3. Project Management</td>
<td>$16,224</td>
<td>$17,472</td>
<td>$18,720</td>
</tr>
<tr>
<td>4. CII</td>
<td>$17,971</td>
<td>$19,353.50</td>
<td>$20,736</td>
</tr>
<tr>
<td>5. Pentest</td>
<td>$17,000</td>
<td>$17,000</td>
<td>$17,000</td>
</tr>
<tr>
<td><strong>Total Costs (Vendor)</strong></td>
<td><strong>$139,054</strong></td>
<td><strong>$148,827</strong></td>
<td><strong>$158,600</strong></td>
</tr>
<tr>
<td><strong>Additional Costs</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. Internal EMC Manpower</td>
<td>$62,400</td>
<td>$66,800</td>
<td>$71,200</td>
</tr>
<tr>
<td>2. Additional costs for code merge and testing if it happens before NEMSCAP Refresh Go-live, expected Oct 2021</td>
<td>$6,552</td>
<td>$7,644</td>
<td>$8,736</td>
</tr>
<tr>
<td><strong>Total Additional Implementation Cost</strong></td>
<td><strong>$68,952</strong></td>
<td><strong>$74,444</strong></td>
<td><strong>$79,936</strong></td>
</tr>
<tr>
<td><strong>Total Cost (Assuming project Go-live before Oct 2021)</strong></td>
<td><strong>$208,006</strong></td>
<td><strong>$223,271</strong></td>
<td><strong>$238,536</strong></td>
</tr>
</tbody>
</table>
### Time Estimates

<table>
<thead>
<tr>
<th></th>
<th>(1) RTS + STS</th>
<th>(2) PDS + Option (1)</th>
<th>(3) MOS + Option (2)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0. Vendor Selection/Preparation</td>
<td>8 Calendar Weeks</td>
<td>8 Calendar Weeks</td>
<td>8 Calendar Weeks</td>
</tr>
<tr>
<td>1. Change Requirement Scoping and Analysis</td>
<td>3 Calendar Weeks</td>
<td>3 Calendar Weeks</td>
<td>3 Calendar Weeks</td>
</tr>
<tr>
<td>2. System Development/Testing/Project Management</td>
<td>10 Calendar Weeks</td>
<td>11 Calendar Weeks</td>
<td>12 Calendar Weeks</td>
</tr>
<tr>
<td>3. User Acceptance Testing (UAT)</td>
<td>5 Calendar Weeks</td>
<td>5 Calendar Weeks</td>
<td>5 Calendar Weeks</td>
</tr>
<tr>
<td><strong>Total Elapse Time in Calendar Weeks</strong></td>
<td><strong>26 Calendar Weeks</strong></td>
<td><strong>27 Calendar Weeks</strong></td>
<td><strong>28 Calendar Weeks</strong></td>
</tr>
</tbody>
</table>

### Usefulness of Information

We expect that different MPs would find the provision of forecasted RRS for the various schedules useful. However, the usefulness of these forecasts increases the closer to real-time that they are generated.

### Table 3: Costs and Benefits of Publishing forecasted RRS for All Schedules or Limited Set of Schedules

<table>
<thead>
<tr>
<th></th>
<th>All Schedules</th>
<th>Limited Set of Schedules</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Costs</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Higher implementation and recurring costs</td>
<td></td>
<td>Lower information transparency</td>
</tr>
<tr>
<td>Potentially higher cost to MPs to manage larger volume of data</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Dispatch schedules which are further from the real-time dispatch is less useful than those that are nearer to the real-time dispatch</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Benefits</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Higher information transparency</td>
<td></td>
<td>Lower cost to MPs to manage the data</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Lower implementation and recurring costs</td>
</tr>
</tbody>
</table>

### 4.3 Provision of Forecasted RRS to All MPs or Owner-MPs only

As discussed in Section 3.1, there are benefits to be gained from market information transparency in general. However, most of the benefits listed in Section 3.1 can be gained by providing forecasted RRS to the respective owner-MPs. This is in line with the current practice for RRS.

Publishing forecasted RRS to all MPs can facilitate anti-competitive behaviour. MPs gain the opportunity to monitor the behaviour of one another and can engage in collusion. Section 3.2 has shown that pockets of periods exist in recent times in which pivotal MPs can exercise market power. Also, larger MPs would potentially enjoy greater benefits, as discussed in Section 3.1. Competition can be further undermined by enhancing the larger MPs’ ability to exercise market power, to the detriment of consumers.
5. Decision at the 118th RCP Meeting

The concept paper was discussed at the 118th RCP meeting and the panel by majority vote:

1. Supported the proposal for EMC to:
   a. use the existing RRS calculation methodology to calculate forecasted RRS
   b. calculate forecasted RRS for RTS, STS and PDS
   c. provide forecasted RRS to the relevant owner-MPs only; and

2. task EMC to draft the required market rules to effect the provision of forecasted RRS.

The following Panel members supported EMC’s recommendation:

1. Mr. Henry Gan (Representative of EMC)
2. Mr. Marcus Tan (Representative of Generation Licensee)
3. Mr. Tony Tan (Representative of Generation Licensee)
4. Mr. Sean Chan (Representative of Retail Electricity Licensee)
5. Mr. Sim Meng Khuan (Representative of Retail Electricity Licensee)
6. Mr. Matthew Yeo (Representative of Wholesale Electricity Trader)
7. Ms. Ho Yin Shan (Representative of the Market Support Services Licensee)
8. Dr. Toh Mun Heng (Representative of Consumers of Electricity in Singapore)
9. Mr. Fong Yeng Keong (Representative of Consumers of Electricity in Singapore)
10. Mr. Tan Chian Khong (Person experienced in financial matters in Singapore)

The following Panel members did not support:

1. Mr. Soh Yap Choon (Representative of PSO)
2. Mr. Teo Chin Hau (Representative of Generation Licensee)

The following Panel members abstained from voting:

1. Ms. Carol Tan (Representative of the Transmission Licensee)

6. Implementation Options

Arising from the RCP’s decisions at the 118th RCP meeting, we consulted the EMC’s Markets Operations team and Technology team on the costs and implementation timeline. 2 options were proposed:

- Option 1: To provide the real-time estimates of RRS for GRF as value-added service.
- Option 2: To provide the real-time estimate of RRS for GRF as a market rule obligation imposed on EMC.

The main differences between the 2 options arise from:
- Implementation costs and timeline
- The expected service standard levels.
6.1 Comparison of the Two Options

Table 3 below provides a summary of the costs and implementation timeline\(^9\) for both options. Table 4 provides a summary of the expected service level standards for both options.

### Table 3: Comparison of Costs and Time for Option 1 and Option 2

<table>
<thead>
<tr>
<th>Cost Estimates</th>
<th>Option (1)</th>
<th>Option (2)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Analysis and Requirement Gathering/Sharing</td>
<td>$9,984</td>
<td>$9,984</td>
</tr>
<tr>
<td>2. Development / Testing / Deployment</td>
<td>$85,017.50</td>
<td>$102,436</td>
</tr>
<tr>
<td>Documentation /</td>
<td></td>
<td></td>
</tr>
<tr>
<td>3. Project Management</td>
<td>$17,472</td>
<td>$20,717</td>
</tr>
<tr>
<td>4. CII</td>
<td>$19,353.50</td>
<td>$22,948</td>
</tr>
<tr>
<td>5. Pentest</td>
<td>$17,000</td>
<td>$17,000</td>
</tr>
<tr>
<td>Total Costs (Vendor)</td>
<td>$148,827</td>
<td>$173,085</td>
</tr>
<tr>
<td>Additional Costs</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. Internal EMC Manpower</td>
<td>$66,800</td>
<td>$110,079</td>
</tr>
<tr>
<td>2. Additional Upgrade to Infrastructure</td>
<td>$15,700</td>
<td>$822,100</td>
</tr>
<tr>
<td>Total Additional Implementation Cost</td>
<td>$82,500</td>
<td>$932,179</td>
</tr>
<tr>
<td>Total Cost</td>
<td>$231,327</td>
<td>$1,105,264</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Time Estimates</th>
<th>Option (1)</th>
<th>Option (2)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0. Vendor Selection/Preparation</td>
<td>8 Calendar Weeks</td>
<td>8 Calendar Weeks</td>
</tr>
<tr>
<td>1. Change Requirement Scoping and Analysis</td>
<td>3 Calendar Weeks</td>
<td>6 Calendar Weeks</td>
</tr>
<tr>
<td>2. System Development/Testing/Project</td>
<td>11 Calendar Weeks</td>
<td>28 Calendar Weeks</td>
</tr>
<tr>
<td>Management</td>
<td></td>
<td></td>
</tr>
<tr>
<td>3. User Acceptance Testing (UAT)</td>
<td>5 Calendar Weeks</td>
<td>5 Calendar Weeks</td>
</tr>
<tr>
<td>Total Elapse Time in Calendar Weeks</td>
<td>27 Calendar Weeks</td>
<td>47 Calendar Weeks</td>
</tr>
</tbody>
</table>

### Table 4: Expected Service Level Standards for Option 1 and Option 2

<table>
<thead>
<tr>
<th>Service Standard Levels</th>
<th>Option (1)</th>
<th>Option (2)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Auto-Recovery and Re-run of forecasted RRS</td>
<td>No</td>
<td>Yes</td>
</tr>
<tr>
<td>information due to system issues(^{10})</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2. Time-Lag of RRS for RTS, STS and PDS</td>
<td>T + 2 Hours (Best Effort)</td>
<td>T + 1 hour</td>
</tr>
</tbody>
</table>

\(^9\) EMC is expecting to start the project after the NEMSCAP Refresh project go-live in Oct 2021 as time is required for EMC to seek both EMC Board and EMA’s approval on the project. Additional infrastructure costs were also factored into the original costs to cater for more storage space to store these data. As a result, even though there is a slight dip in costs ($7,644) due to the project starting after NEMSCAP project go-live in Oct 2021, the additional infrastructure costs ($15,700) resulted in a higher the total costs ($231,327) under Option 1.

\(^{10}\) The proposed auto-recovery process for option 2 will be similar to the current EMC’s recovery process for the various dispatch schedules.
6.2 Proposed Rule Modification

For Option 1, no modification to the Market Rules is required. This approach is similar to the 2014 amendment to the Hourly Energy Uplift Charges\(^\text{11}\) in where new information was added to the monthly trading report.

For Option 2, Table 5 below provides a summary of the proposed modifications to the Market Rules. The detailed modifications are set out in Annex B.

<table>
<thead>
<tr>
<th>S/N</th>
<th>Chapter/Section</th>
<th>Proposed Changes</th>
<th>Reasons for Changes</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.</td>
<td>Chapter 6, Section 7.7.3A and 7.4.3B (New Sections)</td>
<td>Added requirement for EMC to release the estimated RRS to relevant owner-MP only in pre-dispatch schedule and short-term schedule</td>
<td>To require EMC to release the estimated RRS to the relevant owner-MP following the release of the pre-dispatch schedule and short-term schedule</td>
</tr>
<tr>
<td>2.</td>
<td>Chapter 6, Section 9.2.3A. (New Section)</td>
<td>Added requirement for EMC to release the estimated RRS to relevant owner-MP only for real time dispatch schedule</td>
<td>To require EMC to release the estimated RRS to the relevant owner-MP following the release of the real time dispatch schedule</td>
</tr>
<tr>
<td>3.</td>
<td>Chapter 6, Appendix 6N (New Appendix)</td>
<td>Added the methodology for calculating estimated RRS</td>
<td>To refer to the approved methodology for calculation of the estimated RRS (which is set out in Chapter 7, Appendix 7A).</td>
</tr>
</tbody>
</table>

7. Legal Sign-Off

The text of the proposed rule modifications in Annex B has been vetted by EMC’s internal legal counsel, whose opinion is that the proposed rule modifications reflect the rationale for the rule modifications proposal as expressed in the third column of the table in Annex B.

8. Consultation

The rule change paper was published for consultation on 15 April 2021 and comments were received from 7 stakeholders.

Comments from Power System Operator (PSO)

PSO would suggest providing the real-time estimates of RRS for GRF as value-added service (option 1) with much longer publication lag time, which is similar to the publication of the delayed offer stacks. This approach of sharing delayed data could prevent collusion risk and transient market power. In addition, PSO would suggest taking the least cost approach
EMC’s Response

EMC noted PSO’s preference for Option 1.

EMC opined that the risk of collusion and ‘transient’ market power is mitigated partially by releasing the forecasted RRS to relevant owner-MPs only. Therefore, EMC does not recommend further lengthening the publication lag time, which could reduce the usefulness of forecasted RRS to the relevant owner-MPs.

Comments from PacificLight Power (PLP)

PLP is of the opinion that publishing of forecast RRS at this point will only yield benefits to specific group of MPs. Hence, costs should correspondingly be recovered from participating MPs.

We support the implementation of Option 1 as it is a more cost-effective measure. However, we would suggest it to be implemented as a subscription-based service. MPs who are interested with the data can subscribe and pay for these services similar to other subscription offering currently provided by EMC (e.g. historical information)

EMC’s Response

EMC noted PLP’s preference for Option 1.

EMC also noted PLP’s comment to recover the costs of implementation only from interested MPs. However, EMC would like to highlight that our recommendations to RCP take into account benefits and costs to the industry as a whole. As a principle, EMC does not seek to differentiate between classes of MPs when implementing changes that are beneficial to the market as a whole.

Comments from YTL PowerSeraya

YTL PowerSeraya prefer to support Option 1 to provide the RRS estimates as a value-added service and need not make this as a market rules obligation. However, we would like EMC to review the time needed for computing and delivering this data to the MPs as 2 hours seems far too long than is likely needed with today’s computing power.

As an added clarification, we like to confirm that there is no difference in the means by which EMC recovers the implementation and future ongoing costs, whether or not it is as a value-added service or a market rules obligation.

EMC’s Response

EMC noted YTL PowerSeraya’s preference for Option 1.

EMC is proposing a balanced approach in project implementation by considering IT infrastructure costs, MPs’ benefits and the impact on current wholesale market operations. With minimal upgrades to the current IT infrastructure, calculation of forecasted RRS could only occur when the utilization of computing resources is low. Therefore, the impact of calculating forecasted RRS on the current wholesale market operation would be low. EMC assessed that a time-lag of 2 hours optimizes the number of time windows available to run forecasted RRS. As a result, the probability of delays and/or the non-eventuality of releasing the forecasted RRS would be acceptable.

EMC is proposing to recover the implementation costs in the same way as other current NEMS projects, regardless of whether it is a value-added service or a market rules obligation.
Comments from SembCogen

Sembcogen is supportive of Option 1 (RTS + STS). There is a variance in cost for Option 1 in Table 2 (Section 4.2) and Table 3 (Section 6.1). **Is there a reason for the variance?**

**What are the underlying reasons for the time-lag in Table 4?**

Given the availability of dispatch information is prompt, the given time-lag seems disproportionately large. Assuming Option 1 in Table 4, for any given period T, the latest RRS estimate before gate-closure at period T-3 will be based on the dispatch schedule from T-7. This 7-period lag is likely to result in an ineffective RRS estimate, especially when there is over-/under-forecasts in System Load and/or any supply changes.

Referencing to Period 39 on 1st April 2021, the medium-load forecast rose by more than 350MW from T-7 to T, which can easily skew a generator’s RRS as scheduled dispatch increases. This seems to negate the benefits stated in Section 3.1.

**Hence, we opined that the release of RRS estimates is more effective if there is no time-lag and is in tandem to the release of LAR schedule.**

**EMC’s Response**

The main variances in cost between Option 1 in Table 2 and Table 3 can be attributed to the additional of PDS schedule, the removal of code merging before the NEMSCAP Refresh Project go-live in Oct 2021 and the additional storage costs that is required to store the additional data which was not included in the previous estimate presented to the RCP.

EMC is proposing a balanced approach in project implementation by considering IT infrastructure costs, MPs’ benefits and the impact on current wholesale market operations. With minimal upgrades to the current IT infrastructure, calculation of forecasted RRS could only occur when the utilization of computing resources is low. Therefore, the impact of calculating forecasted RRS on the current wholesale market operation would be low. EMC assessed that a time-lag of 2 hours optimizes the number of time windows available to run forecasted RRS. As a result, the probability of delays and/or the non-eventuality of releasing the forecasted RRS would be acceptable.

Comments from Tuas Power (Tuas)

**We are of the view that T+1 hour publication of the forecasted RRS data may be more useful for the market participant to understand their reserve allocation.** As such, we would like to request for information on the impact on cost and implementation timeline for Option 1, if the publication timeline can be shortened to T+1 hour.

**EMC’s Response**

If the release timeline is shortened to no later than T+1 hour and with minimal upgrade to existing IT infrastructure, the possibility of delays and/or the non-eventuality of releasing the forecasted RRS would be higher.

EMC opined that forecasted RRS is more a “good to have” than “must have” information. Therefore, EMC would propose to a time lag of 2 hours to balance IT infrastructure costs, MPs’ benefits and the impact on current wholesale market operations.
Comments from KMC

Keppel suggests further clarification on the quantitative cost-benefit analysis of option (1) and option (2). In particular, option (2) requires a relatively high implementation cost that should be further deliberated by the RCP.

EMC’s Response

EMC noted KMC’s comments. Nevertheless, for this proposal, it is not possible to objectively quantify the benefits of information availability to MPs, in the way we can objectively quantify the implementation cost.

Comments from Senoko

Could EMC elaborate further on the “Best effort” for Option 1. Does this mean that MPs could expect delays or the non-eventuality of the forecasted RRS being published?

As this set of data drives and moves trading decisions, Option 2 appears to be the more robust approach to this implementation in which we are supportive of. Could EMC share the horizon or period that this additional cost will be recovered? As a result, also share based on the cost recovery, the expected uplift in charges for both options 1 & 2.

EMC’s Response

There will be a probability of delay and/or the non-eventuality of the forecasted RRS being released in Option 1. This probability varies with the time-lag associated with releasing the information. The probability of relevant-owner MPs receiving the forecasted RRS will be higher with a longer time lag. Option 1 optimizes the use of existing infrastructure to provide the information to relevant owners-MPs with minimal cost increase.

EMC noted Senoko’s preference for Option 2. EMC is unable to provide the horizon or period that this additional cost will be recovered over at this point. This requires assumptions on when the project will be approved by the EMA.

9. Conclusion and Recommendations

EMC assessed the two options for the implementation approach for providing real-time estimates of RRS for each GRF.

Although the release of forecasted RRS will enhance market transparency, EMC assessed that the cost of Option 2 would be much higher than Option 1.

There were also a significant number of feedbacks received from the industry preferring implementing the project as a value-added service to MPs (Option 1).

Therefore, EMC recommend RCP to support the following:

- Implement the forecasted RRS as a value-added service to MPs
- On a best effort basis, for EMC to release the information to relevant owner-MPs within two hours of releasing the corresponding forecast schedules
- No Auto-recovery or Re-run of forecasted RRS due to system issues
10. Decision at the 123rd RCP Meeting

The rule change proposal was discussed at the 123rd RCP meeting. The Panel by majority vote supported EMC’s recommendation to:

a) Implement the forecasted RRS as a value-added service to MPs;
b) On a best effort basis, for EMC to release the information to relevant owner-MPs within two hours of releasing the corresponding forecast schedules;
c) No Auto-recovery or Re-run of forecasted RRS due to system issues

The following Panel members supported EMC’s recommendation:

1. Mr. Henry Gan (Representative of EMC)
2. Mr. Calvin Quek (Representative of Generation Licensee)
3. Ms. Carol Tan (Representative of Transmission Licensee)
4. Mr. Sean Chan (Representative of Retail Electricity Licensee)
5. Mr. Terence Ang (Representative of Retail Electricity Licensee)
6. Mr. Song Jian En (Representative of Retail Electricity Licensee)
7. Mr. Cheong Zhen Siong (Representative of Wholesale Electricity Trader)
8. Ms. Ho Yin Shan (Representative of the Market Support Services Licensee)
9. Dr. Toh Mun Heng (Representative of Consumers of Electricity in Singapore)
10. Mr. Fong Yeng Keong (Representative of Consumers of Electricity in Singapore)
11. Mr. Tan Chian Khong (Person experienced in financial matters in Singapore)

The following Panel members did not support:

1. Mr. Soh Yap Choon (Representative of PSO)
2. Mr. Teo Chin Hau (Representative of Generation Licensee)
3. Mr. Tony Tan (Representative of Generation Licensee)
Annex A - HHI and RSI Analysis of the SWEM

Herfindahl-Hirschman Index (HHI)

The HHI is commonly used by market monitors and regulators globally as a measure of market concentration. The HHI increases as the number of firms in the market decreases and/or the disparity in size between firms increases. A higher HHI generally indicates greater market concentration, with near zero being perfect competition and 10,000 being a monopoly.

The United States Department of Justice and the Federal Trade Commission classify markets into 3 types, namely Unconcentrated Market (HHI below 1,000), Moderately Concentrated Markets (HHI between 1,000 and 1,800) and Highly Concentrated Markets.

The HHI is calculated by summing the square of the market share (in decimal) of each firm in a market and multiplying by 10,000. For the purposes of this paper, the market share is computed based on the MP’s registered units’ capacity with EMC.

Generally, the SWEM’s HHI has been falling since Jan 2013 from a highly concentrated market (HHI: 2,516) to a moderately concentrated market (1,532 as of May 2020). Please refer to Table A1 below for the historical HHI.

<table>
<thead>
<tr>
<th>Month</th>
<th>Herfindahl-Hirschman Index (HHI)</th>
</tr>
</thead>
<tbody>
<tr>
<td>May-20</td>
<td>1,532</td>
</tr>
<tr>
<td>Apr-20</td>
<td>1,532</td>
</tr>
<tr>
<td>Mar-20</td>
<td>1,532</td>
</tr>
<tr>
<td>Feb-20</td>
<td>1,532</td>
</tr>
<tr>
<td>Jan-20</td>
<td>1,533</td>
</tr>
<tr>
<td>Jan-19</td>
<td>1,663</td>
</tr>
<tr>
<td>Jan-18</td>
<td>1,680</td>
</tr>
<tr>
<td>Jan-17</td>
<td>1,709</td>
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<tr>
<td>Jan-16</td>
<td>1,812</td>
</tr>
<tr>
<td>Jan-15</td>
<td>1,838</td>
</tr>
<tr>
<td>Jan-14</td>
<td>2,021</td>
</tr>
<tr>
<td>Jan-13</td>
<td>2,516</td>
</tr>
<tr>
<td>Jan-12</td>
<td>2,430</td>
</tr>
</tbody>
</table>

The HHI thresholds used in this paper are based on the thresholds adopted by FERC using the US DOJ and FTC’s 1992 guidelines, see https://www.ferc.gov/whats-new/comm-meet/2012/021612/E-2.pdf.

12 The HHI thresholds used in this paper are based on the thresholds adopted by FERC using the US DOJ and FTC’s 1992 guidelines, see https://www.ferc.gov/whats-new/comm-meet/2012/021612/E-2.pdf.
Residual Supplier Index (RSI)

The RSI is another commonly established concentration index used by competition regulators and market monitors. Specifically, the RSI measures the extent to which competitors of a given MP can meet the current demand with their supply offers.

For any MP, the RSI is defined as follows:

$$RSI = \frac{\text{total available supply} - \text{MP total supply}}{\text{market demand}}$$

An inverse relationship between the RSI and the Lerner Index, a well-known measure of competition, can be derived. Based on certain assumptions of a profit maximization oligopoly firm facing a residual demand, it can be shown that the Lerner Index is a simple linear function of RSI such that the RSI is a compelling explanatory variable for price-cost margins.

The RSI is usually expressed as a decimal number. If the RSI has a value of 1 and above in each half hour period, it would mean that other competing MPs are able to meet 100% of demand. Hence an RSI value greater than one indicates that the MP has little influence on the market price. Conversely, the MP is pivotal if the RSI is less than one.

For the purpose of this paper, supply is defined as energy offers that were used by the MCE to generate the real-time dispatch schedule. Similarly, demand is defined as the forecast demand for energy used by MCE to generate the real time dispatch schedule. The number of pivotal suppliers is defined as the number of MPs that failed the threshold of $RSI < 1$. Data from 1 Jan 2019 – 31 May 2020 was used in the computation of the RSI resulting in 24,816 observation points.

![Figure A1: Percentage of periods where pivotal suppliers are present across the day (2019)](image)

13 Please refer to the following document by CAISO on a summary of how RSI is used to monitor market power and a brief explanation on how RSI is related to the Lerner Index. Link

14 Energy supply offers were used instead of the reserve offers as a pivotal MP is more likely to exercise market power in the energy market than the reserve markets as they need to pay for reserve charges. Furthermore, forecasted RRS will give MPs an idea on what is the possible energy dispatch schedule of the largest unit rather than the reserve dispatch schedule.
Both Figure A1 and Figure A2 show that the ability for a pivotal MP to exercise market power exists during peak periods in which energy demand is high. In 2019, the number of pivotal MPs from Period 1 – 14 (0.1% of the total periods) was minimal. However, in the first 5 months of 2020, periods with at least 1 pivotal supplier increased slightly to 1.5% of total periods for the same reference periods. Another observation is that periods with no pivotal MPs during the peak periods (P20 – P24) increased from 34.3% in 2019 to 41.4% in the first 5 months of 2020.

**Table A2: Summary of Pivotal Suppliers Over 2019 – 2020 (As of 31 May 2020)**

<table>
<thead>
<tr>
<th>Year</th>
<th>0</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
</tr>
</thead>
<tbody>
<tr>
<td>2019</td>
<td>67.7%</td>
<td>15.1%</td>
<td>13.2%</td>
<td>3.2%</td>
<td>0.8%</td>
<td>0.0%</td>
</tr>
<tr>
<td>2020</td>
<td>66.5%</td>
<td>9.2%</td>
<td>15.4%</td>
<td>7.6%</td>
<td>1.3%</td>
<td>0.1%</td>
</tr>
</tbody>
</table>

Overall, the number of periods in which pivotal MPs exist increased slightly from 32.3% to 33.5%. Interestingly, there was also an increase in the maximum number of pivotal MPs from 4 in 2019 to 5 in the first 5 months of 2020.

Therefore, we assess that concerns on ‘transient’ market power are still valid even though for more than 65% of the time, no pivotal MP existed based on the analysis above. The ability to exercise of market power by pivotal MPs is still possible during certain parts of the day. Therefore, releasing information that can facilitate anti-competitive behaviour has to be considered carefully.
## Annex B: Proposed Rule Modifications

<table>
<thead>
<tr>
<th>Existing Market Rules</th>
<th>Proposed Rule Changes</th>
<th>Reasons for Rule Changes</th>
</tr>
</thead>
</table>
| **Market Operation – Release of Scenario Information**  
(Chapter 6 Market Rules) | **Market Operation – Release of Scenario Information**  
(Chapter 6 Market Rules) |  
| **7.7**  
**RELEASE OF SCENARIO INFORMATION**  
... | **7.7**  
**RELEASE OF SCENARIO INFORMATION**  
... | To allow EMC to release the estimated RRS to the relevant owner-MP following the release of the pre-dispatch schedule and short-term schedule |
|  
7.7.3A Not later than 60 minutes after the commencement of the first dispatch period of the pre-dispatch schedule referred to in section 7.4.1, the EMC shall, for each dispatch period covered by the pre-dispatch schedule, release the estimated reserve responsibility share with respect to each generation registered facility to the dispatch coordinator for that generation registered facility, as determined in accordance with Appendix 6N. |  
7.7.3A Not later than 60 minutes after the commencement of the first dispatch period of the pre-dispatch schedule referred to in section 7.4.1, the EMC shall, for each dispatch period covered by the pre-dispatch schedule, release the estimated reserve responsibility share with respect to each generation registered facility to the dispatch coordinator for that generation registered facility, as determined in accordance with Appendix 6N. |  |
|  
7.7.3B Not later than 60 minutes after the commencement of the first dispatch period of each of the three short-term schedules referred to in section 7.4A.1, the EMC shall, for each dispatch period covered by the short-term schedule, release the estimated reserve responsibility share with respect to each generation registered facility to the dispatch coordinator for that generation registered facility, as determined in accordance with Appendix 6N. |  
7.7.3B Not later than 60 minutes after the commencement of the first dispatch period of each of the three short-term schedules referred to in section 7.4A.1, the EMC shall, for each dispatch period covered by the short-term schedule, release the estimated reserve responsibility share with respect to each generation registered facility to the dispatch coordinator for that generation registered facility, as determined in accordance with Appendix 6N. |  |
9.2 THE REAL-TIME SCHEDULING PROCESS

... 

9.2.3A Not later than 60 minutes after the release of the real-time dispatch schedule referred to in section 9.2.1.1, the EMC shall, for that dispatch period, release the estimated reserve responsibility share with respect to each generation registered facility to the dispatch coordinator for that generation registered facility, as determined in accordance with Appendix 6N.

Calculation of Estimated Reserve Responsibility Shares
(Appendix 6N Market Rules)

APPENDIX N – CALCULATION OF ESTIMATED RESERVE RESPONSIBILITY SHARES

N.1 PURPOSE

N.1.1 This Appendix describes the procedure that the EMC shall use to determine the estimated reserve responsibility shares (RRSs) for the purpose of allocating the costs of reserves among GRFs in each dispatch period as contemplated in sections 7.7.3A, 7.7.3B and 9.2.3A of this Chapter. Unless otherwise indicated, each procedure described in this Appendix shall be applied for each dispatch period.

N.2 DEFINITIONS

N.2.1 In this Appendix:
N.2.1.1 a reference to the “size” of a GRF in a dispatch period shall be designated by $SZ$, where,

$$SZ = \frac{1}{2}\text{-hour} \times \text{energy scheduled (in MW)}$$

from the pre-dispatch schedule, short-term schedule, or real-time dispatch schedule for that GRF in that dispatch period.

N.2.1.2 “secondary contingency unit” or SCU means a GRF that is expected to disconnect automatically from the transmission system if the frequency of the transmission system falls due to the failure of the largest GRF, and “SCU m” refers to the SCU at MNN m.

N.2.1.3 “cut-off size” or CSZ (in MWh) means the size below which a GRF that is not a secondary contingency unit will not pay a share of the cost of reserve but will pay for regulation. CSZ is 5 MWh.

N.2.1.4 “primary contingency unit” or PCU means a GRF whose size is greater than CSZ and that is not a secondary contingency unit, and:

a. “PCU m” refers to the PCU at MNN m; and

b. “PCU z” refers to the PCU with size index $Z$;

N.2.1.5 “probability of failure”, in respect of a GRF, means the probability that the GRF will, after being dispatched by PSO for a dispatch period, cease operating, disconnect from the transmission system, or both in that dispatch period even if no other GRF fails.
Explanatory Note: Please refer to the explanatory note in Appendix 7A.

**N.3 IDENTIFICATION OF SECONDARY CONTINGENCY UNITS**

N.3.1 The EMC shall identify the secondary contingency units in accordance to Appendix 7A, Section A.3.

**N.4 IDENTIFICATION AND ORDERING OF PRIMARY CONTINGENCY UNITS**

N.4.1 The EMC shall identify and order the primary contingency units in accordance to Appendix 7A, Section A.4.

**N.5 RESERVE REQUIREMENTS**

N.5.1 The primary reserve requirement or PRQ (in MWh) shall be defined as follows:

\[
PRQ = SZ(m(1)) = OSZ(1) = \text{size of largest PCU}
\]

N.5.2 The secondary reserve requirement or SRQ (in MWh) shall be defined as follows:

\[
SRQ = \sum s \cdot SZ(s), \text{ where } s = \text{all MNNs corresponding to SCUs having } SZ(s) > 0
\]

N.5.3 The total reserve requirement (TRQ, in MWh) shall be defined as follows:

\[
TRQ = SRQ + PRQ
\]
N.6 RESERVE TIERS AND RESERVE TIER SHARES

N.6.1 That amount of primary reserve requirement referred to in section N.5.1 which is in excess of CSZ shall be divided into “tiers” defined by the sizes of the PCUs. The term “reserve tier z” shall mean the portion of the primary reserve requirement between the size of PCU z+1 and the size of PCU z.

N.6.2 The reserve tier quantity for reserve tier z or RTQ(z) shall be defined as follows:

\[ RTQ(z) = OSZ(z) - OSZ(z+1), \text{ with } OSZ(Z+1) = CSZ \]

N.6.3 The reserve tier shares for reserve tier z or RTS(z) shall be defined as follows:

\[ RTS(z) = RTQ(z)/(PRQ - CSZ) \]

N.7 FAILURE PROBABILITIES AND WEIGHTS

N.7.1 The EMC shall follow the established procedures stated in Appendix 7A, Section A.7, for determining and updating of the probability of failure of each GRF.

N.7.2 For each dispatch period, the EMC shall use the data in the probability of failure register referred to in Appendix 7A, section A.7.2 and the size-ordering of PCUs for that dispatch period determined in accordance with section N.4 to determine the interval probabilities of failure of IPF (z) and interval probability weights or IPW (z) for each PCU as follows:

\[ IPF(z) = SPF(m(z)) \]

Where:
\[ IPW(z) = \sum_{i=1}^{z} IPF(i) \]

Where:

\[ z = PCU z \]

### N.8 RRSs FOR SECONDARY CONTINGENCY UNITS

N.8.1 The EMC shall determine the reserve responsibility share (RRS) for an SCU in a dispatch period in accordance with the following formula:

\[ RRS_{R, h m} = \begin{cases} 0 & \text{in cases where } SZ(m) \leq 0; \\
SZ(m)/TRQ & \text{otherwise,}
\end{cases} \]

where:

- \( m = SCU m \)
- \( h = dispatch\ period\ h \)

\( SZ(m) \) is determined for \( SCU m \) in accordance with this Appendix for \( dispatch\ period\ h \).

### N.9 RRSs FOR PRIMARY CONTINGENCY UNITS

N.9.1 The ordered reserve share for a PCU or ORS\( z \) shall be defined in accordance to Appendix 7A, Section A.9.1.

N.9.2 The EMC shall determine the reserve responsibility share (RRS) for a PCU in a settlement interval in accordance with the following formula:

\[ RRS_{R, h m} = ORS(z(m)) \]

where:

- \( m = PCU m \)
- \( h = dispatch\ period\ h \)
$z(m)$ is the size-index of $PCU_m$

ORS($z(m)$) is determined for PCU $z(m)$ in accordance with this Appendix for dispatch period $h$. 