Energy
Market
Company

RCP PAPER NO.	:	**EMC/RCP/89/2016/CP63**
SUBJECT	:	**PRICE ASSIGNMENT FOR ISLANDED GENERATION FACILITIES**
FOR	:	**DECISION**
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DATE OF MEETING	:	**6 SEPTEMBER 2016**

Executive Summary

Currently, when the market clearing engine (MCE) produces an anomalous[1] market energy price (MEP) for a generation facility (GF)[2] in the real-time schedule due to the GF being islanded[3], EMC conducts price revision by rerunning the MCE with its islanded alternate default bus replaced by a suitable non-islanded bus, selected in consultation with the Power System Operator (PSO). Although an islanded GF would not have been scheduled, such price revision is necessary to correct the price signal to the market and the islanded GF's price at which its auxiliary/station load, if any, is settled.

It is proposed that the MCE determines prices for islanded GFs in the real-time and forecast schedules ex-ante, instead of revising anomalous prices in the real-time schedules ex-post. This is because, under the current arrangement, the prolonged

[1] The MEP of a GF is described as 'anomalous' when it does not reflect the GF's locational marginal price.
[2] In this paper, a GF refers to both a generation settlement facility (GSF) and a generation registered facility (GRF).
[3] For the purpose of this paper, a GSF is islanded when both its main and alternate default buses are islanded, while a GRF is islanded when all its GU(s) are islanded. A bus is islanded when (1) it is not physically connected as per the Network Status File (NSF) or Outage Schedule File (OSF), or **(2) it is physically connected as per the NSF or OSF but the grid it belongs to does not have any load**. A GU is islanded when (1) it is not represented as synchronised in the dispatch network data and (2) its main and alternate default buses are islanded. This usually results when the GF or the substation it is connected to is on maintenance.

islanding of a GF exacerbates the problem by resulting in the need for price revisions in multiple consecutive periods.

After reviewing the practices in U.S. electricity markets for determining prices for islanded GFs, EMC explores Option 1, a methodology to derive prices for islanded GFs ex-ante by approximating their locational marginal prices (LMPs) using the prices of their neighbouring buses. Alternatively, EMC seeks the PSO's views on Option 2, an arrangement where the PSO promptly updates the default bus designation of a GF expected to be persistently islanded.

At the 28th TWG meeting held on 28 June 2016, the TWG had divergent views on this issue. One TWG member considered that Option 1 is complex and yet, would not eliminate the need for price revisions arising from islanded GFs, and hence preferred simpler methods in place of Option 1. Two TWG members felt that the islanding issue happens rarely and does not justify the cost of implementing Option 1. On the other hand, other TWG members recognised that Option 1 would incur reasonable implementation time and costs while preserving the SWEM's locational marginal pricing principle.

At the 88th RCP meeting held on 12 July 2016, the RCP concluded that they would like to defer making a decision on this proposal. The RCP requested for EMC to assess the following:

(i) the risks and complexity associated with Option 1;
(ii) the option of assigning USEP to islanded GFs (Option 3); and
(iii) the time and costs required by the status quo and Options 1 and 3.

Both the status quo and Option 1 preserves the locational marginal pricing principle in the SWEM. Although Option 1 more closely aligns with the ex-ante pricing principle in the SWEM as compared to the status quo at a reasonable cost, EMC MO has reiterated concerns with the risks and complexity associated with its implementation. Furthermore, a closer examination of the costs incurred by EMC for the status quo reveals that the recurring costs were low. Thus, maintaining the status quo is preferred.

At the 89th RCP meeting held on 6 September 2016, the RCP **by majority vote support** maintaining the status quo.

1. Introduction

This paper assesses the proposal to determine prices for islanded GFs in the real-time and forecast schedules ex-ante, instead of revising their anomalous prices in the real-time schedules ex-post. The rationale of this proposal is to reduce the need for price revisions, especially if GFs are islanded for multiple consecutive periods.

2. Background

2.1 Pricing Principles

Ex-Ante Pricing with Ex-Post Revisions

The Singapore Wholesale Electricity Market (SWEM) adopts an ex-ante pricing regime whereby the spot prices are determined by the MCE before the start of each half-hour dispatch period. Nevertheless, there are provisions in the market rules for ex-post price revisions under certain circumstances. The rationale for ex-ante pricing is certainty in the prices used for settlement by MPs prior to purchase and sale. On the other hand, ex-post revisions of ex-ante prices ensures equity and fairness by not making MPs receive or pay wrong prices through no fault of their own, and also price accuracy by having revised prices being reflective of prevailing market conditions.

Locational Marginal Pricing

In the SWEM, the MCE uses locational marginal pricing to determine the prices of energy purchase and dispatch at each node in the market network. Each nodal price incorporates the effects of transmission losses and constraints such as security constraints and regulation or reserve co-optimisation, in order to reflect the cost incurred by the system to meet the incremental or decremental demand at the respective location. Using these nodal prices, the MCE also determines the Uniform Singapore Energy Price (USEP), the average of such nodal prices weighted by the energy withdrawn at each node.

For settlement purposes, the SWEM takes a half-nodal pricing approach, in which generators are paid for their generation and charged for their consumption of station/auxiliary load at their nodal prices while consumer loads are charged for their consumption at the USEP. It is believed that settlement based on LMPs for generators can contribute to economic efficiency by optimally guiding market behaviour and decision-making by MPs, while settlement based on the USEP for consumer loads can ensure that loads are not disadvantaged by location. As a result, loads' response to locational price signals is limited. Uniform pricing for consumer loads is a compromise between accurate economic signalling and social policy objectives.

- **Locational Pricing**

Locational pricing enables the true costs of generation and consumption at any location to be truly compared, promoting better decision-making in both short and long term. In the short term, consumers or generators can decide to adjust demand or generation during certain trading periods. In the long term, the LMPs guide investment decisions by determining the best location for new generation and transmission capacity and perhaps even the best location for new industrial loads.

- **Marginal Pricing**

Marginal pricing encourages generators to offer energy at their true opportunity cost, regardless of the expected market clearing price. This is done by dispatching low-cost generation before higher-cost generation and paying all generators the marginal price.

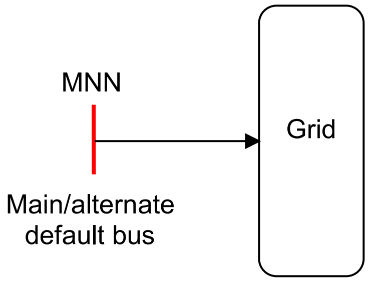
2.2 Nodal Price Derivation for GFs

The MCE derives the nodal prices, also known as MEPs in the SWEM, of GFs at their market network nodes (MNNs)[4].

GSFs[5]

The MNN for a GSF is the dispatch network node (DNN) corresponding to the GSF's designated main default bus or alternate default bus[6] (if the main default bus is islanded). Therefore, regardless of a GSF's physical connectivity captured by the Network Status File (NSF) or Outage Schedule File (OSF) from the PSO, the MCE derives the MEP for the GSF at its designated main or alternate default bus. This configuration is illustrated in Figure 1.

Figure 1: MCE model of a GSF



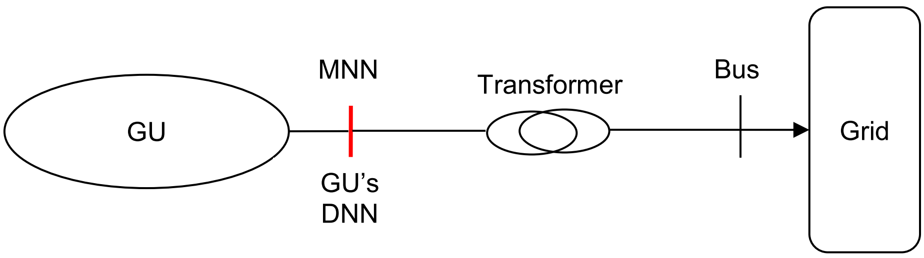
GRFs

- **Single-Unit GRFs**

The DNN representing the generating unit's (GU) point of connection shall be designated the MNN for the single-unit GRF.

When the sole GU of a single-unit GRF is represented as synchronised in the dispatch network data i.e. physically connected to the grid, the MCE derives the MEP for the single-unit GRF at the DNN of its sole GU. Figure 2 depicts how such a single-unit GRF is modelled in the MCE:

Figure 2: MCE model of a single-unit GRF – GU physically connected to the grid



[4] MNNs represent those nodes at which market transactions take place. Thus a dispatch network node (DNN) with no load or generation will not be represented as a MNN.

[5] This paper does not apply to pseudo GSFs. A pseudo GSF has a MNN assigned to it by EMC and the MEP at this assigned MNN is the weighted MEP (WMEP) i.e. average MEP of all GRFs, weighted by the scheduled generation of each GRF.

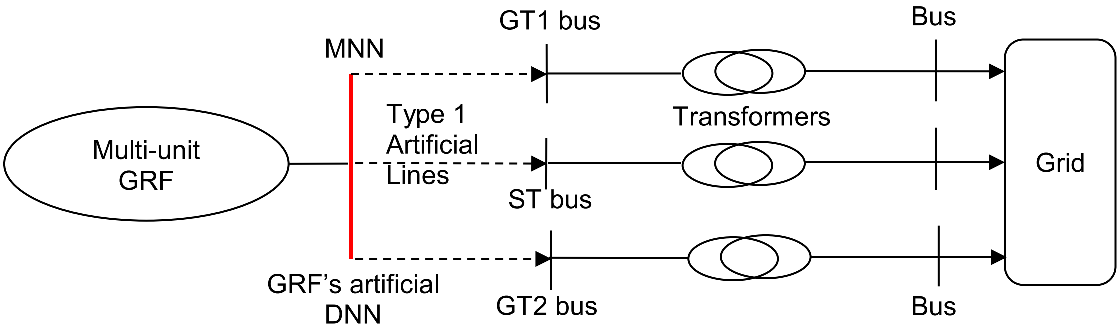
[6] The designation of alternate default buses by the PSO was introduced by RC232 (Alternate Default Bus) in 2004.

- **Multi-Unit GRFs**[7]

A multi-unit GRF will be connected to the dispatch network[8] at an artificially created DNN, which in turn is connected to the DNNs of its individual GUs via <u>Type 1 artificial lines</u>. These artificial lines serve to apportion the multi-unit GRF's energy schedule to its GUs according to the proportionality equations, and the multi-unit GRF's artificial DNN shall be designated the MNN for the multi-unit GRF. The MCE derives the price for a multi-unit GRF at the GRF's artificial DNN.

When all the GUs of a (2 GT + 1 ST) multi-unit GRF are represented as synchronised in the dispatch network data i.e. physically connected to the grid, the MCE models the multi-unit GRF as shown in Figure 3.

<u>Figure 3: MCE model of a multi-unit GRF – all GUs physically connected to the grid</u>



2.3 Connectivity Modelling for Disconnected GFs

A bus is islanded when (1) it is not physically connected as per the NSF or OSF, or (2) it is physically connected as per the NSF or OSF but the grid it belongs to does not have any load.

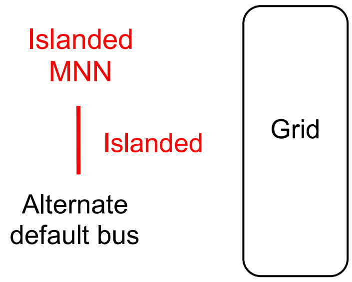
GSFs

If both the designated main and alternate default buses of a GU are islanded as depicted in Figure 4, the <u>GSF is deemed islanded</u>.

[7] There are three types of multi-unit GRF configurations in the SWEM, namely:
- 1 Gas Turbine (GT) + 1 Steam Turbine (ST);
- 2 GT + 1 ST; and
- 1 GT + 1 shared ST

[8] The dispatch network is the representation of the Singaporean network used for dispatch purposes. It comprises dispatch network lines and dispatch network nodes, which may not correspond exactly to physical electricity lines and nodes. EMC may, in consultation with the PSO, simplify or expand the representation of the physical network in ways that do not materially affect scheduling, pricing or settlement, but that simplify the scheduling, pricing or settlement processes.

Figure 4: MCE model of a GSF (islanded GSF)



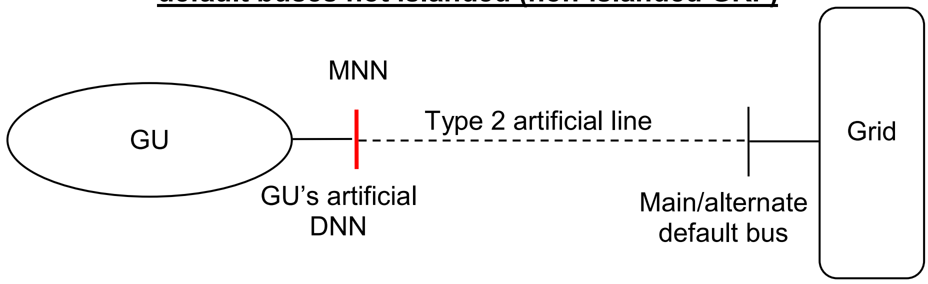
GRFs

A GRF is islanded when all its GU(s) are islanded. A GU is islanded when (1) it is not represented as synchronised in the dispatch network data and (2) both its main and alternate default buses are islanded.

- **Single-Unit GRFs**

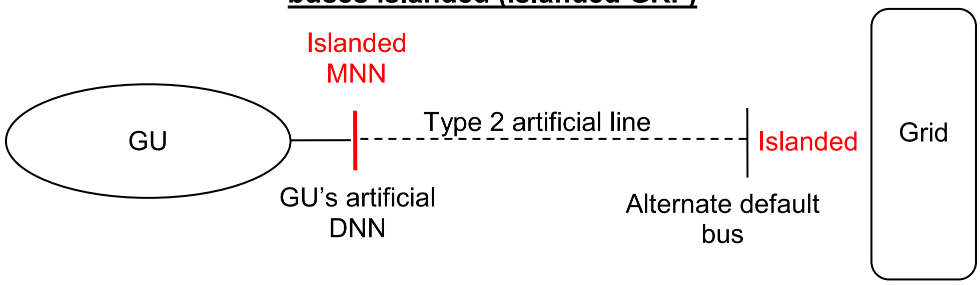
When the sole GU of a single-unit GRF is not represented as synchronised in the NSF or OSF received from the PSO, the GRF is modelled as connected to the dispatch network at an artificially created DNN, which in turn is connected via a Type 2 artificial line to the GU's designated main or alternate default bus (if the main default bus is islanded). This is to allow GRFs to be scheduled for the upcoming periods (including forecast schedules) based on their offers. This configuration is illustrated in Figure 5a. The MCE derives the MEP for the single-unit GRF at the artificial DNN.

Figure 5a: MCE model of a single-unit GRF – GU not synchronised but at least one of its default buses not islanded (non-islanded GRF)



If both the designated main and alternate default buses of a single-unit GRF are islanded, the GRF ends up being islanded as depicted in Figure 5b.

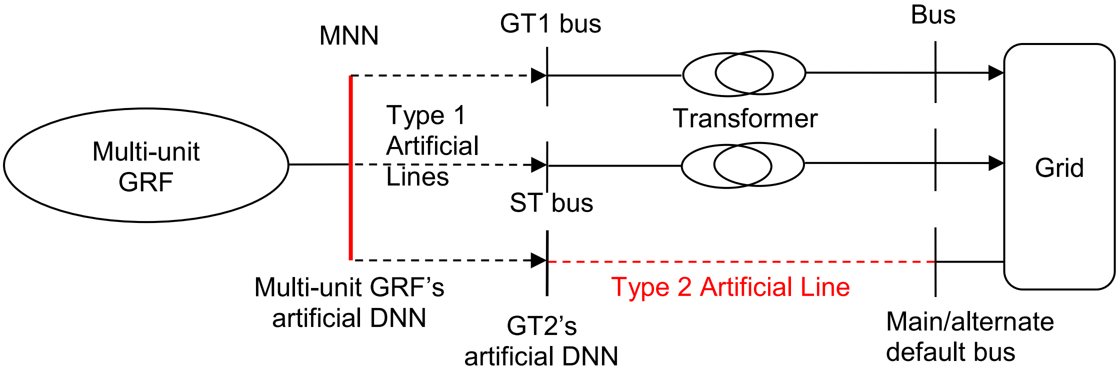
Figure 5b: MCE model of a single-unit GRF – GU not synchronised and both its default buses islanded (islanded GRF)



- **Multi-Unit GRFs**

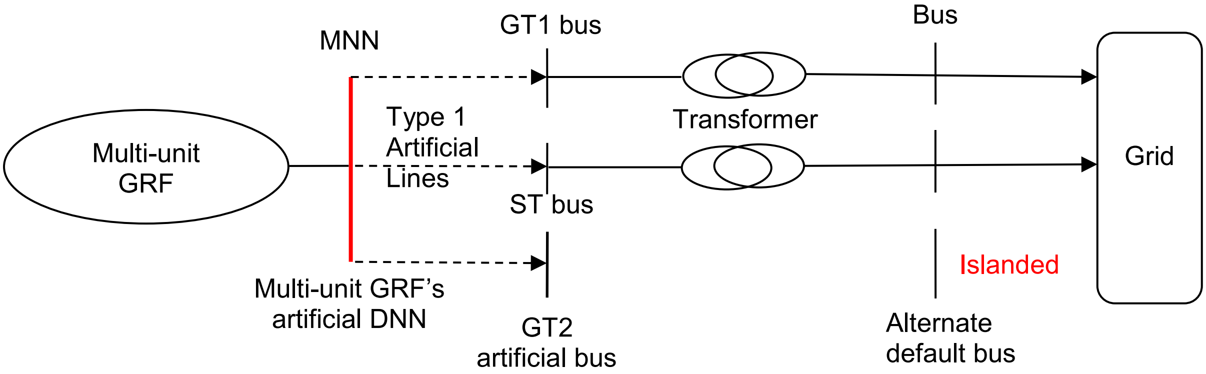
When a GU of the multi-unit GRF is not represented as synchronised in the NSF or OSF received from the PSO, the GU's artificial DNN is connected to its designated main or alternate default bus via a Type 2 artificial line[9]. This is to allow GRFs to be scheduled for the upcoming periods (including forecast schedules) based on their offers. This configuration is illustrated in Figure 6a overleaf.

Figure 6a: MCE model of a multi-unit GRF– one GU not synchronised but at least one of its default buses not islanded (non-islanded GRF)



However, if both the designated main and alternate default buses of the unsynchronized GU are islanded, the GU ends up being islanded. Since not all GUs of the multi-unit GRF are islanded, the MCE does not connect GT2 to its alternate default bus via a Type 2 artificial line. This is to allow the multi-unit GRF to be scheduled in the upcoming dispatch period, albeit only up to the combined capacities of its remaining non-islanded GUs. The price of the multi-unit GRF, derived by the MCE at the multi-unit GRF's artificial DNN, would also be contributed by the DNN prices of the remaining non-islanded GUs, as depicted in Figure 6b.

Figure 6b: MCE model of a multi-unit GRF– one GU not synchronised and both its default buses islanded (islanded GU, but non-islanded GRF)

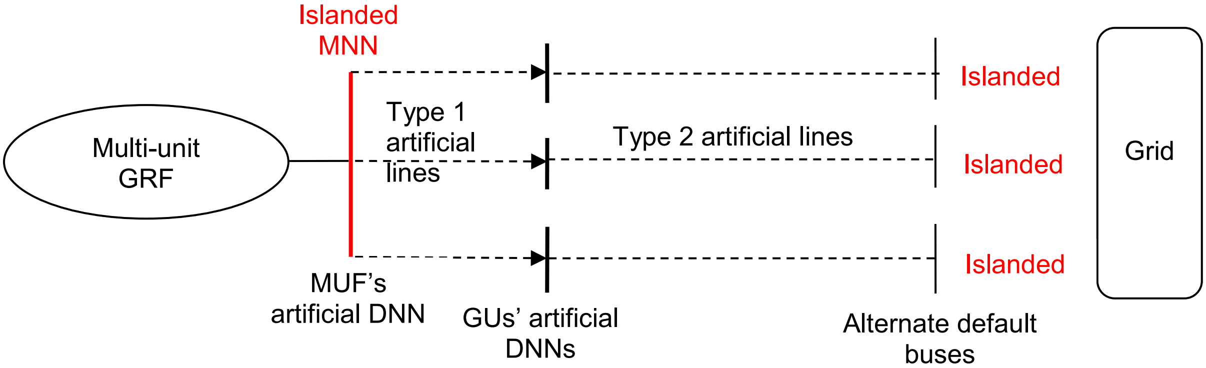


In another scenario where all GUs of the multi-unit GRF are islanded, the MCE connects all the GUs to their alternate default buses via Type 2 artificial lines so as to derive a price for the MUF even though it will not be scheduled. Since their main and alternate default buses are all

[9] As introduced by RC323 (Remodelling of Multi-Unit Facilities) in 2015, the Type 2 artificial line is **not** added for a GU of a multi-unit GRF if the GU is islanded but not all the GUs of that GRF are islanded, in order to allow the remaining non-islanded GUs to be scheduled in the upcoming dispatch period.

islanded, this Type 2 artificial line connection results in the entire multi-unit GRF being islanded as shown in Figure 6c.

Figure 6c: MCE model of a multi-unit GRF – all GUs not synchronised and both their default buses islanded (islanded GRF)



2.4 Pricing Outcomes of Islanded GFs

In accordance with the market rules Appendix 6D Section D.24.1, the MCE determines the MEPs based on prices which are values of dual variables corresponding to the Node Balance Generation constraint in Section D.16.1.2. When a GF is islanded, the problem of the MCE producing **multiple optimal solutions**, i.e. multiple MEPs which achieve the same objective function value across different runs, arises.

According to the PSC Consultants, the MEPs can be determined by calculating the change in total system cost associated with (1) an incremental demand or (2) a decremental demand at the nodes. Table 1 and Figures 7a and 7b illustrate an example of multiple MEPs for an islanded GRF.

Table 1: Derivation of Multiple MEPs for an Islanded GRF

Energy Offer Quantity	Case 1: Incremental Demand	Case 2: Decremental Demand
Positive (as shown in Figure 7a)	**MEP = $Offer Price** Since the node is separated from the system without any load to serve, an incremental demand at the node would incur a cost at the offer price to the system. Hence, the GRF's nodal price i.e. MEP would reflect its offer price.	**MEP = -$4500/MWh** A decremental demand at the node would result in excess generation which incurs a cost at -$5000/MWh, ExcessGenerationPenalty, to the system. Hence, the GRF's nodal price i.e. MEP would reflect the ExcessGenerationPenalty, floored at -$4500/MWh (0.9*ExcessGenerationPenalty).
Zero (as shown in Figure 7b)	**MEP = $4500/MWh** Since the energy offer quantity is zero, an incremental demand at the node cannot be served by scheduling offers. This would result in deficit generation which incurs a cost at $5000/MWh, DeficitGenerationPenalty, to the system. Hence, the GRF's nodal price i.e. MEP would reflect the	**MEP = -$4500/MWh** A decremental demand at the node would result in excess generation which incurs a cost at -$5000/MWh, ExcessGenerationPenalty, to the system. Hence, the GRF's nodal price i.e. MEP would reflect Excess Generation Penalty, floored at -$4500/MWh

Energy Offer Quantity	Case 1: Incremental Demand	Case 2: Decremental Demand
	DeficitGenerationPenalty, capped at $4500/MWh (0.9*DeficitGenerationPenalty).	(0.9*ExcessGenerationPenalty).

Figure 7a: Islanded Single-Unit GRF with Positive Energy Offer Quantity

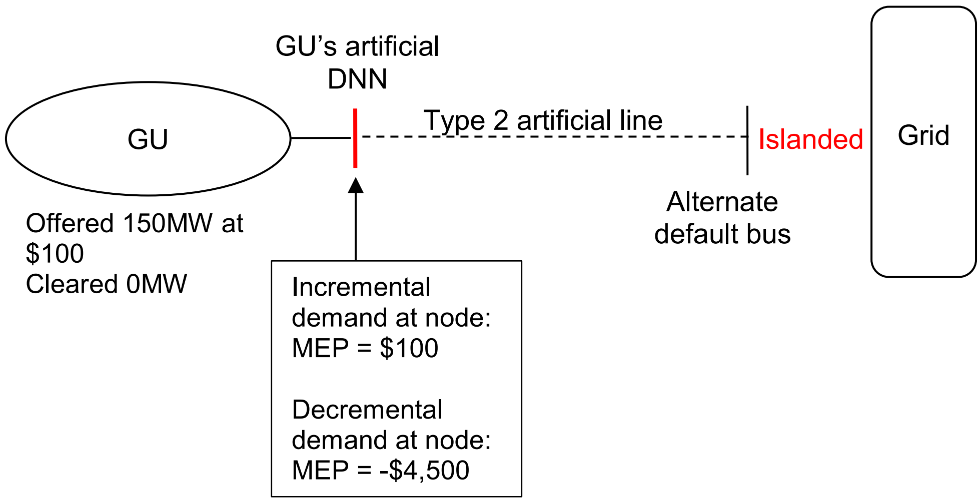
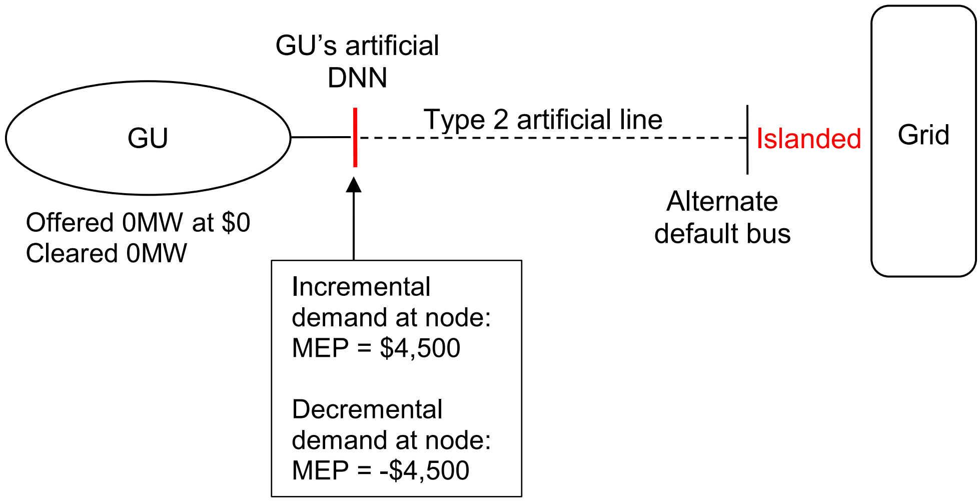


Figure 7b: Islanded Single-Unit GRF with Zero Energy Offer Quantity



3. Analysis

3.1 Practices in U.S. Electricity Markets

We reviewed and summarised in Table 2 the practices in U.S. electricity markets for pricing islanded GFs, i.e. de-energized or disconnected nodes.

Table 2: Pricing of De-Energised/Disconnected Nodes in U.S. Markets

Market	Practices
Pennsylvania-New Jersey-Maryland Interconnection (PJM) [10]	The methodology for determining LMPs at de-energized buses is to assign to them the LMPs at their neighbouring energized buses. The following criteria for a search is designed and implemented in the market clearing software. Search rules: (a) At the same voltage level; (b) At the same station; (c) In the nearest neighbouring stations (rank all the transmission lines out of the de-energised bus station in descending order of their admittances and search down the rank); (d) Manually.
California Independent System Operator (CAISO)[11]	In the event that a Pricing Node becomes electrically disconnected from the market model during a CAISO Market run, the LMP at the closest electrically connected Pricing Node will be used as the LMP at the affected location.
Electric Reliability Council of Texas (ERCOT)[12]	ERCOT shall assign an LMP to de-energized Electrical Buses for use in the calculation of the Real-Time/Day-Ahead Settlement Point Prices by using heuristic rules applied in the following order: (a) Use an appropriate LMP predetermined by ERCOT as applicable to a specific Electrical Bus; or if not so specified (b) Use the following rules in order: (i) Use average LMP for Electrical Buses within the same station having the same voltage level as the de-energized Electrical Bus, if any exist; (ii) Use average LMP for all Electrical Buses within the same station, if any exist; (iii) Use System Lambda[13].

[10] PJM Manual 11: Energy & Ancillary Services Market Operations (31 Mar 2016), Section 2.7.1: Determination of LMPs for de-energized buses, extracted from http://www.pjm.com/~/media/documents/manuals/m11.ashx

[11] CAISO Corporation Fifth Replacement Federal Energy Regulatory Commission (FERC) Electric Tariff (12 Jun 2015), Section 27.1.1: LMPs For Energy, extracted from https://www.caiso.com/Documents/ConformedTariff_Jun12_2015.pdf

[12] ERCOT Nodal Protocols (1 Sep 2015), Section 4.5.1: Day-Ahead Market (DAM) Clearing Process, Section 6.6.1: Real-Time Settlement Point Prices, extracted from http://www.ercot.com/content/wcm/current_guides/53528/04_090115_Nodal.doc and http://www.ercot.com/content/wcm/current_guides/53528/06_090115_Nodal.doc

[13] The System Lambda is "the cost of providing one MWh of energy at the reference Electrical Bus, i.e. the Shadow Price for the power balance constraint, which is equal to the change in the objective function obtained by relaxing the power balance constraint by one MW". It is "the energy component of LMP at each Settlement Point in ERCOT". Extracted from http://www.ercot.com/glossary/s

In general, the U.S. electricity markets derive ex-ante a suitable price for an islanded facility by an automatic search of an electrically nearby or similar bus.

3.2 Current Practice in the SWEM

Conducting Ex-Post Price Revision

As could be seen from the wide range of values the MEP for an islanded GF can possibly take, the islanded GF's MEP may not be reflective of its LMP or be appropriate for use in settlement of its auxiliary or station load. While the designation of an alternate default bus was introduced in 2004 to reduce the occurrences of islanded GFs, it was recognized then that price revision would still need to be relied on as a contingency when both the main and alternate default buses are islanded.

Currently, when the MCE establishes a price which is not LMP-reflective in the real-time schedule, EMC confirms by 12 noon the next trading day that all prices for that dispatch period are provisional. The provisional prices are to be finalised by T+5BD.

Upon investigation that the price which is not LMP-reflective belongs to a GF that is islanded, EMC conducts price revision by performing a MCE rerun using all 'correct' input data that should have been used by the MCE at the time when the MCE runs i.e. T-5mins. For the islanded GF, EMC will, in consultation with the PSO, select a suitable non-islanded bus to replace its islanded alternate default bus for the MCE rerun. Ex-post price revision corrects the anomalous price of the islanded GF for use in the settlement of its station or auxiliary load, as well as for long-term efficiency.

Problem Description

This proposal was triggered by the 2014 cases. In 2014, MCE reruns were conducted on 2 separate occasions for 100 affected periods in total to revise the MEPs of the islanded GRFs from $4500/MWh or $0/MWh to between $114/MWh and $194/MWh. They had minimal impact on other aspects of the overall schedule, specifically:

- No changes to the objective values
- No changes to overall system results including USEP, Losses and Quantities Scheduled for each product; and
- For other GRFs, there were minor changes in the MEPs (up to $0.27/MWh) and the MW cleared (up to 3.62% of pre-rerun MW cleared) for certain CCGT units due to multi-optimality.

In both original runs and reruns, the islanded GRFs were not scheduled for energy and the reruns were conducted solely to establish correct MEPs, given that these islanded GRFs were also not consuming any energy during the affected periods.

Nevertheless, when the GFs are islanded due to the facility or, in worse scenarios, the entire substation being on maintenance and disconnected from the main grid, the need for price reruns could persist for prolonged periods of up to weeks. As a stopgap measure, EMC had in previous occurrences requested for the PSO to update the alternate default bus in the affected GF's standing data to the bus used for rerun, effectively shortening the affected duration.

As shown in Table 3, this problem arose infrequently (0.258% of the time) over the past 5 years, but contributed to **42.4%** of periods of price revision/MCE reruns.

Table 3: Number of Cases from 1 January 2011 to 31 December 2015

Year	Affected Trading Dates & Periods	No. of Affected Periods	No. of Periods	% of Time	No. of Rerun Periods	% of Rerun Periods
2015	NIL	0	17,520	0%	77	0%
2014	26 Aug P23 – 48 25 Mar P23 – 48 26 Mar P1 – 48	100	17,520	0.571%	183	54.6%
2013	NIL	0	17,520	0%	107	0%
2012	17 Apr P39 – 40	0	17,568*	0%	12	0%
2011	01 May P19 – P48 02 May P1 – P48 03 May P1 – P48	126	17,520	0.719%	154	81.8%
2011 to 2015		**226**	87,648	**0.258%**	533	**42.4%**

* 2012 is a leap year with 366 days, i.e. 17,568 periods

3.3 Proposed Options

3.3.1 Option 1: Derivation of Prices for Islanded GFs Ex-Ante

Taking reference from the U.S. markets' practices of assigning the LMP of the closest bus or the average LMP of the closest buses to the islanded unit as per Section 3.1 in this paper, we attempt to formulate a similar methodology, to derive a price for islanded GFs ex-ante in the SWEM so as to reduce the need for reruns, and subsequently assess whether the derived prices are likely to be reflective of the LMP of the islanded GFs.

To recap, the purpose of default buses is to represent the most likely connection points at which GUs[14] that are not synchronised can be represented as connected in the dispatch network, so that

- the GF has the opportunity to be scheduled if its offers (if any) can be scheduled, and
- the GF's MEP can be correctly determined by the MCE for settlement of (a) its generation or (b) its auxiliary/station load, if any.

In essence, this methodology, if adopted, will require that the MCE:

- identify the nearest bus(es) of each GU based on the bus connectivity information used in real-time schedules **for prior dispatch periods** (hereafter referred to as "neighbouring buses"); and
- use the prices of neighbouring buses that are neither islanded nor eliminated by the network simplification process **in dispatch period T** (hereafter referred to as "valid neighbouring buses") to determine the MEP of the islanded GF in real-time and forecast schedules for **dispatch period T**.

3.3.1.1 Identifying Neighbouring Buses

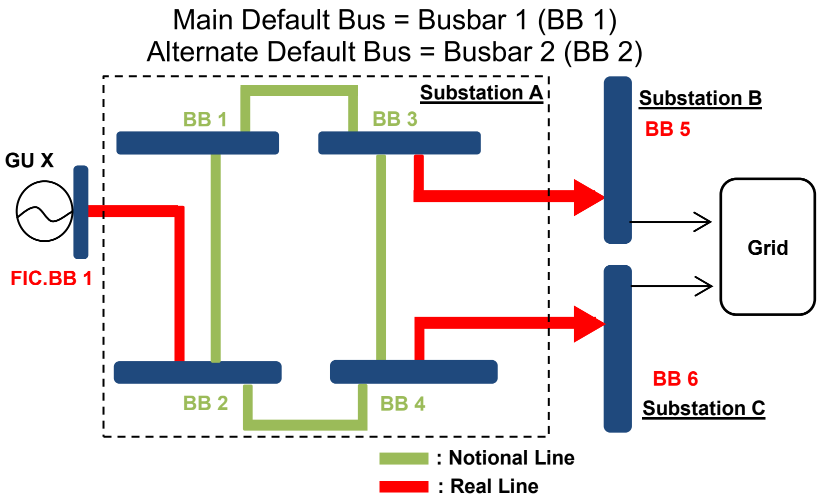
The proposed methodology requires that the MCE identify and maintain a database of sets of neighbouring buses for all GUs using the bus connectivity information used in producing real-time dispatch schedules. There are 2 types of neighbouring buses, Type A being those usually

[14] All subsequent references to GUs apply to the GSFs and the GUs of GRFs.

from the same substation as their main and alternate default buses, and Type B being those usually from the neighbouring substation(s)[15].

The MCE updates the database set of neighbouring buses for a GU in a dispatch period only when according to the latest bus connectivity information, (1) the GU is not islanded from the grid, and (2) the MCE identifies a new set of neighbouring buses, that contains both Type A and Type B neighbouring buses, for the GU.

Figure 8a: Connectivity of Non-Islanded GU for Dispatch Period T-1



For example, if a single-unit GU X in Substation A is (1) not islanded and (2) has the connectivity shown in Figure 8a above which is used in producing a real-time dispatch schedule for a dispatch period, say dispatch period T-1, the following neighbouring buses will be discovered and updated in the database by the MCE:

1. Type A: Busbar 1 (BB 1), Busbar 2 (BB 2), Busbar 3 (BB 3) and Busbar 4 (BB 4)
2. Type B: Fictional Busbar 1(FIC. BB), Busbar 5 (BB 5) and Busbar 6 (BB 6)

3.3.1.2 Using the Prices of Valid[16] Neighbouring Buses

When a GSF, single-unit GRF or a multi-unit GRF is islanded (as depicted in Figures 4, 5b and 6c respectively in Section 2.3) in a particular dispatch period, the price of the islanded GF is determined as per this section.

The price of each GU will be the **average**[17] of the prices of:
1. All the GU's valid Type A neighbouring buses, or
2. All its valid Type B neighbouring buses, if the GU does not have any Type A neighbouring buses

in dispatch period T.

[15] A GU's Type A neighbouring buses are proxied by buses connected by one or more notional lines to the GU's main and/or alternate default buses, whereas its Type B neighbouring buses are proxied by buses connected by only one real line to its Type A neighbouring buses.
[16] A bus is deemed 'valid' in a dispatch period if it is neither islanded nor eliminated by the network simplification process in that dispatch period.
[17] For simplicity, we averaged the price of the relevant neighbouring buses to obtain the GU's price. The benefit of further distinguishing the proximity of the neighbouring buses according to their admittances or reactances is limited given the high complexity.

The computation of an islanded GF's MEP would be **<u>based on the existing formulae</u>** in the market rules Appendix 6D Section D.24.1, with the derived price(s) of the islanded GF's GU(s) replacing EnergyPrice in the formulae outlined below.

<u>For GSF or Single-Unit GRF:</u>

$$\mathrm{MEP}^{m(g)} = \text{EnergyPrice}_{n(m)}$$

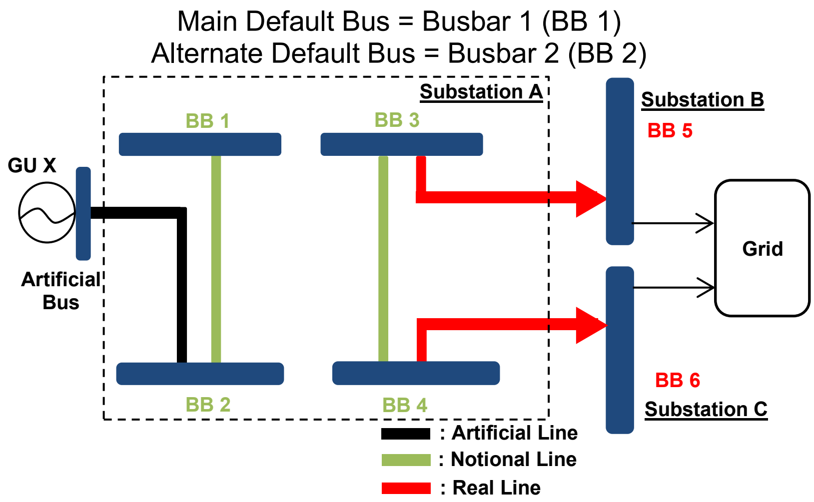
<u>For Multi-Unit GRF:</u>

$$\mathrm{MEP}^{m(g)} = \frac{\sum_{u \in \mathrm{CONNECTEDUNITS}_g} (\mathrm{Proportion}_u \times \text{EnergyPrice}_{n(u)})}{\sum_{u \in \mathrm{CONNECTEDUNITS}_g} \mathrm{Proportion}_u}$$

If any GU of an islanded GF does not have any valid Type A or Type B neighbouring bus for that dispatch period, for instance when the substation that it is connected to and the neighbouring substations are all islanded, the MEP for the islanded GF will still be anomalous and price revision is still required ex-post.

Continuing from the earlier example, when GU X is islanded in dispatch period T due to itself being islanded as shown in Figure 8b, its price would be determined by the prices of its valid Type A neighbouring buses, BB 3 and BB 4, in that dispatch period. BB 1 and BB 2 are invalid as they are islanded.

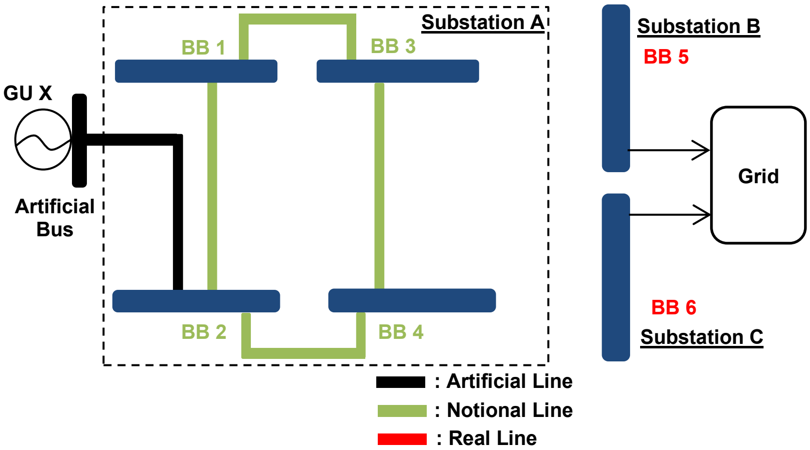
<u>Figure 8b: Connectivity of Islanded GU for Dispatch Period T (Only the GU is islanded)</u>



When the GU is islanded in dispatch period T due to the entire substation that the GU's default buses are connected to being islanded as shown in Figure 8c, its price would then be determined by the prices of its valid Type B neighbouring buses, BB 5 and BB 6, in that dispatch period. This is because Type A neighbouring buses, BB 1 to BB 4, are all islanded and invalid. FIC.BB 1 is also invalid as it is eliminated by the network simplification process in that dispatch period.

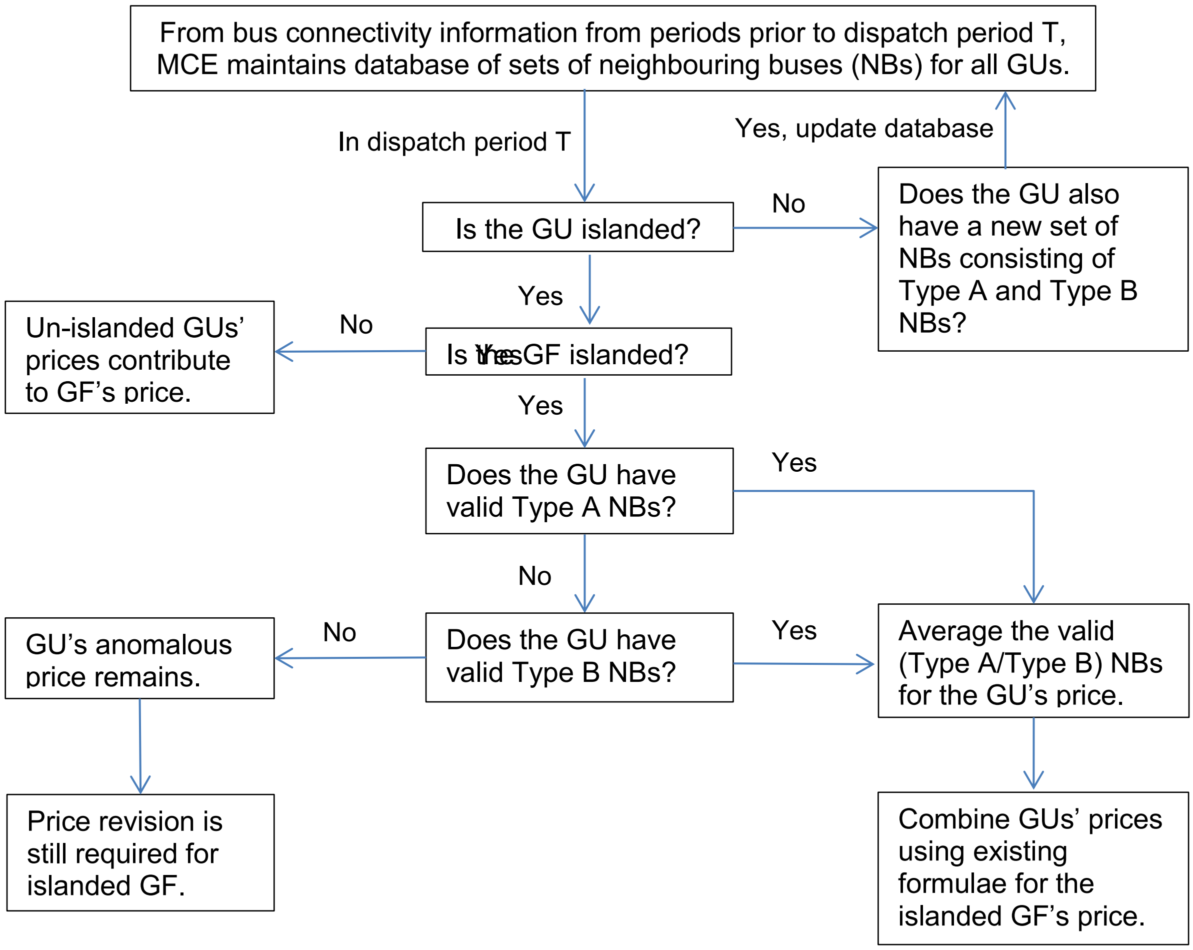
Figure 8c: Connectivity of Islanded GU for Dispatch Period T (Substation is islanded)

Main Default Bus = Busbar 1 (BB 1)
Alternate Default Bus = Busbar 2 (BB 2)



3.3.1.3 Flowchart of Proposed Process

Figure 9: Proposed Process of Database Update and Derivation of Islanded GF's Price



3.3.1.4 Assessment of Proposed Methodology

To assess the reliability and robustness of prices derived under the methodology, we applied the methodology on three scenarios to compare the derived MEPs with the actual/revised MEPs, as described in Table 4. The results for each scenario are summarised in Table 5.

Table 4: Description of Study Scenarios

Scenario	**Scenario 1** Periods with neither price separation[18] nor price revision	**Scenario 2** Periods with only price separation	**Scenario 3** Periods with only Type 5 price revision due to islanding of GFs only
Rationale	To assess the reliability of the methodology in producing MEPs consistently similar to the actual MEPs for all GFs under normal conditions.	To assess the robustness of the methodology in producing MEPs that do not deviate too much from the actual MEPs for all GFs under conditions of significant nodal price separation.	To assess the effectiveness of the methodology on producing MEPs consistently similar to the revised MEPs under status quo for the islanded GFs under normal conditions.
Periods Assessed	1 – 10 Apr 2016 All periods, except 8 Apr 2016 Period 26 (i.e. 479)	20 Oct 2015 Periods 23 – 24, 26 – 43 21 Oct 2015 Periods 14 – 39 (i.e. 46)	<u>Islanding due to islanded GF:</u> 26 Aug 2014 Periods 23 – 48 (i.e. 26) <u>Islanding due to islanded substation:</u> 25 Mar 2014 Periods 23 – 48 26 Mar 2014 Periods 1 – 48 (i.e. 74)
Network Status File Used	31 Mar 2016 Period 48	30 Sep 2015 Period 48	25 Mar 2014 Period 22
GFs Assessed	All GFs (i.e. 59)	All GFs (i.e. 59)	Islanded GFs (i.e. 2)
MEPs Compared	Actual MEPs vs. Derived MEPs	Actual MEPs vs. Derived MEPs	Revised MEPs vs. Derived MEPs
Bus Prices Used for Derivation of MEPs	Bus prices of each GU's valid neighbouring bus(es)[19], excluding their main/alternate default buses	Actual prices of each GU's valid neighbouring bus(es)[19], excluding their main/alternate default buses	Pre-rerun prices of each GU's valid neighbouring bus(es)

[18] A period is deemed to have price separation when the ratio of the highest MEP to the lowest MEP in the dispatch period exceeds 1.05 as established in CP61 (Proposed Measures to Mitigate Price Separation).
[19] For Scenarios 1 and 2, a GU's Type A neighbouring buses are proxied by buses directly connected by <u>**one notional line**</u> to the GU's main and/or alternate default buses (which is a subset of that proposed under footnote 15, where indirect connections to the main and/or alternate default buses by <u>**many notional lines**</u> are also included), and its Type B neighbouring buses are proxied by buses connected by only one real line to <u>**its main and/or alternate default buses**</u> (which is a subset of that proposed under footnote 15, where connections to <u>**all its Type A neighbouring buses**</u> by only one real line are also included).

Table 5: Study Results

Scenario	Scenario 1 Periods with neither price separation nor price revision		Scenario 2 Periods with only price separation		Scenario 3 Periods with only Type 5 price revision due to islanding of GFs	
Islanding due to islanded:	**GF**	**Substation**	**GF**	**Substation**	**GF**	**Substation**
Average Absolute Difference[20]	0.16%	0.14%	0.18%	0.67%	0%	0.07%
Maximum Absolute Difference	1.98%	1.74%	0.72%	32.12%	0%	0.11%

As seen from Scenario 3, the methodology is highly effective when applied to the islanded GFs of the 2014 cases. As expected, when the GF is islanded due to itself being islanded, the use of its Type A neighbouring buses under the methodology produces prices identical to its revised prices under status quo. In addition, when the GF is islanded due to its substation being islanded, the use of its Type B neighbouring buses under the methodology produces prices that differ from its revised prices minimally.

As shown by Scenarios 1 and 2, the methodology is suboptimal only when there is price separation and when islanding of the GF is due to its islanded substation, where the maximum absolute difference reaches 32.12%. In fact, the abnormally high average and maximum absolute differences are contributed by a single GF, hereafter referred to as “GF Y”. Without GF Y, the average and maximum absolute differences will remain at 0.16% and 0.73% respectively. This is because while GF Y is at the high-priced downstream of the binding security constraint, a subset of the valid Type B neighbouring buses of its GUs is from a substation at the low-priced upstream of the constraint. The use of neighbouring buses with vastly different prices to derive the MEPs of GF Y leads to significant deviations from its actual MEPs.

In summary, the proposed methodology has features to achieve various objectives for an improvement from the status quo with regards to the pricing of islanded GFs, as outlined in Table 6.

Table 6: Features of Proposed Methodology

Features of Proposed Methodology	Rationale
Updating Database	Maintain relevance of database based on latest actual connectivity
Hierarchy in Neighbouring Buses Used	Preserve locational marginal pricing as far as possible under different islanding scenarios

[20] The absolute difference (in percentage) in MEPs for each GF g in a dispatch period is calculated using the following formula:

$$\text{Absolute Difference}_g = \frac{|\,(\text{Derived MEP}_g - \text{Actual/Revised MEP}_g)\,|}{\text{Actual MEP}_g} \times 100\%$$

The average and maximum absolute differences are derived across all periods and GFs.

Nonetheless, if implemented, the MEPs determined for the real-time schedule using the methodology will still be subject to price checks by the EMC to determine if price revision is required. If the determined MEP is still considered to be not reflective of the GF's LMP, such as that for GF Y in Scenario 2 where its islanding is due to its islanded substation, EMC will provisionalise the price and proceed to conduct price revision when required upon investigation.

3.3.2 Option 2: PSO to Update Default Buses of Islanded GUs

Under the current market rules, the PSO is required to designate default buses for all GUs, representing their most likely connection points to the dispatch network. We seek the PSO's views on whether the designated default buses of a GU, that is expected to be persistently islanded, is still its most likely connection points to the dispatch network. If not, moving forward, can the PSO update (at least) the designated alternate default bus of such a GU promptly so as to shorten the affected duration requiring reruns?

3.3.3 Assessment of Options

Table 7: Comparison of Options 1 and 2

	Option 1: Derivation of Prices for Islanded GFs Ex-Ante	Option 2: PSO to Update Default Buses of Islanded GUs
Pros	• Need for price revisions would be reduced	• Need for price revisions would be reduced • Does not require system changes
Cons	• Require system changes and incur implementation costs (See Table 8) • Need for price revisions would not be entirely eliminated	• Need for price revisions would persist till at least the end of trading day before updated standing data takes effect

4. Implementation Time and Costs (For Option 1)

The breakdown of the estimated implementation time and costs for Option 1 are set out in Table 8 below.

Table 8: Estimated Implementation Time and Costs for Option 1

Time Estimates	Effort Estimates (Man weeks)	Lapse Time (Calendar weeks)
1. Change Requirement Scoping and Analysis	1	1
2. MCE Development and Testing	3	5
3. User Acceptance Testing	3	4
4. Audit	2	3
Total Time Required	**9**	**13**
Cost Estimates		
1. Power Systems Consultant Resource/EMC Manpower	$36,725 (Within EMC's budget)	
2. External resource to support	N.A	
3. Audit	$25,000	
Total Additional Cost Required	**$25,000**	

5. Conclusion

This proposal seeks to correct price anomalies for islanded GFs ex-ante in both real-time and forecast schedules to more closely align with the ex-ante pricing principle in the SWEM. The paper explores Option 1, a methodology which uses electrically nearby buses to derive LMP-reflective prices for the islanded GFs, and Option 2, an arrangement where the PSO promptly updates the default bus designation for GFs expected to be persistently islanded.

6. Industry Consultation

The concept paper was published for industry consultation on 31 May 2016 and comments were received from PacificLight Power and the PSO.

Comments from PacificLight Power

PLP is supportive of adhoc enhancements to the MCE that create greater robustness. However we believe that for Option 1 the costs and resources required to implement the scheme outweigh any benefits that it could achieve. Our view is substantiated by the following factors:

- During the period 2011-2015, there were infrequent occurrences of Generation Registered Facility (GRF) being islanded. Based on past records, it happened only 0.258% of the time over the past 5 years.
- Although there were occurrences in 2014 which affected 100 periods, the impact was minimal. Notably, there were no changes to overall system results including USEP, Losses and Quantities Scheduled for each product.
- Though there have been vast improvements in the derived prices in proximity to the revised prices when applied to the case of Islanded GFs during 2014 using the proposed methodology under Option 1, its implementation cost is $25,000 and does not entirely eliminate such occurrences.
- Ex-ante derivation methodology may possibly burden the MCE run prior to each dispatch period (i.e. T-5 minutes).

As such, PLP does not support the implementation of Option 1.

EMC's Response

While the problem that both options aim to tackle currently occurred only 0.258% of the time in the last 5 years, the problem contributed to almost half of the price revisions required in the same time duration. The need for price revisions should be minimised as far as possible to improve market confidence and price certainty. While we recognise that both options have their limitations in entirely eliminating the need for price revisions, either option would be an improvement from the status quo.

With regards to the concern on the impact of Option 1 on the MCE's performance, if Option 1 were to be supported, the impact would be immaterial.

Comments from the PSO

- Option 1 is preferred as it is more effective in deriving the prices of islanded GFs in advance, thus better in fulfilling the ex-ante principle of the NEMS.
- The use of Option 1 is also consistent with other jurisdictions.
- PSO could, in many instances, not be able to know in advance, due to operational uncertainty, whether the main and default busbars would be disconnected in the MCE. As a result, re-runs would still be required.

- Therefore, in Table 7 under Option 2, it may not be correct to state that the need for price revisions would be reduced. Perhaps could be reduced then.
- An automated solution in Option 1 will be able to provide more reliability to the Market Participants of the islanded GFs and the NEMS as a whole in achieving the stated objectives.

<u>EMC's Response</u>

We note the PSO's support for Option 1.

We also note that for Option 2, in addition to (a) the standing data update taking effect only at the end of the trading day, (b) the uncertainty of the PSO knowing in advance whether GUs are expected to be persistently islanded lowers the effectiveness of the option in reducing the need for price revisions.

Option 1, on the other hand, would make use of all latest available inputs in the MCE to derive a LMP-reflective price for an islanded GF as far as possible. The effectiveness of the option is possibly hampered by only extraordinary circumstances like price separation occurrences.

7. TWG's Deliberation and Decision at the 28th TWG Meeting

At the 28th TWG meeting held on 28 June 2016, EMC recommended that the TWG support the proposal to implement Option 1.

The TWG had divergent views on this issue. One TWG member considered that Option 1 is complex and yet, would not eliminate the need for price revisions arising from islanded GFs, and hence preferred simpler methods in place of Option 1. Two TWG members felt that the islanding issue happens rarely and does not justify the cost of implementing Option 1. On the other hand, other TWG members recognised that Option 1 would incur reasonable implementation time and costs while preserving the SWEM's locational marginal pricing principle.

In conclusion, the members who <u>supported</u> Option 1 are:

1. Mr. Liu Jidong (YTL PowerSeraya)
2. Mr. Loh Poh Soon (PSO)
3. Mr. Lionel Lee (SP PowerGrid)

The members who <u>did not support</u> Option 1 are:

1. Mr. Chua Gwen Hong (Sembcorp Cogen)
2. Ms. Tini Mulyawati (Keppel Merlimau Cogen)
3. Ms. Bai Jie (EMC)

Mr. Lionel Lee added that his view is conditional on EMC Market Operations (MO) being comfortable with implementing the change.

8. RCP's Deliberation and Decision at the 88th RCP Meeting

At the 88th RCP meeting held on 12 July 2016, the TWG recommended that the RCP decide whether to support the proposal to implement Option 1.

The RCP concluded that they would like to defer making a decision on this proposal. The RCP requested for EMC to assess the following:

(i) the risks and complexity associated with Option 1;
(ii) the option of assigning USEP to islanded GFs (Option 3); and
(iii) the time and costs required by the status quo and Options 1 and 3.

EMC's analysis is set out in Section 9.

9. Further Analysis

9.1 Risks and Complexity Associated with Option 1

EMC MO has identified the following risks and complexity associated with Option 1:

1. Longer Processing Time Required
   Based on the performance of the prototype, there was 7 seconds or 50% increase from the current NWSTAT processing time. The risk for delayed MCE DPR runs is low since our current NWSTAT processing time is well below the threshold. However, if in future the PSO decides to send NWSTAT at a later time, or the market evolves to a 5-minute dispatch schedule, the performance impact would be heightened.

2. Larger Data Storage Required
   Currently, the NWSTAT processing alone takes about 50Mbyte and the total of DPR result tables take another 50Mbyte per day. Assuming that only the neighbouring buses of default buses are to be stored in the table, it is estimated that 20 Mbyte of additional data storage per day (i.e. 7.3 GB per year) is required. Nevertheless, this additional storage requirement is still within the current storage capacity.

3. High Complexity Involved
   The neighbouring bus algorithm is highly complex. Its dependence on the Oracle technology also means that we are constrained by this technology. Whenever there are changes required, the maintenance of this algorithm is complex as well, posing risks to the market.

9.2 Option 3: Assigning USEP to Islanded GFs

Recall from Sections 2.1 of the paper that the USEP is the average nodal price weighted by the energy withdrawn at each node. Currently, the USEP is used to settle consumption by loads.

Proponents of Option 3 contend that an islanded GF does not have an electrical location in the network and hence, locational marginal pricing need not be applied. They further argue that the USEP is an appropriate price to assign to islanded GFs because the price of such GFs is solely used to settle the consumption of its auxiliary/station load.

Our view is that assigning USEP to islanded GFs is a deviation from the locational marginal pricing principle. This is supported empirically by the large absolute differences between USEP and the actual/revised MEPs as shown in Table 9 overleaf.

Table 9: Updated Study Results

Scenario	Scenario 1 Periods with neither price separation nor price revision		Scenario 2 Periods with only price separation[21]		Scenario 3 Periods with only Type 5 price revision due to islanding of GFs	
Option 1						
Islanding due to islanded:	**GF**	**Substation**	**GF**	**Substation**	**GF**	**Substation**
Average Absolute Difference	0.16%	0.14%	0.18%	0.67%	0%	0.07%
Maximum Absolute Difference	1.98%	1.74%	0.72%	32.12%	0%	0.11%
Option 3						
Average Absolute Difference	0.73%		83.72%		1.39%	
Maximum Absolute Difference	3.21%		468.56%		1.64%	

Moreover, if we follow the argument of aligning the settlement of the consumption of the auxiliary/station loads of islanded GFs with the settlement of the consumption of loads, the price assigned should include not only USEP, but also Hourly Energy Uplift Charge (HEUC) and Monthly Energy Uplift Charge (MEUC), which will entail significant system changes.

Overall, we do not consider that there is any justification to implement Option 3.

9.3 Comparison of Time and Costs Required

<u>Recurring Time and Costs</u>

The costs are computed from the time using MO's project rate of $465 per man day i.e. 8 man hours.

The estimated recurring time and costs for **the status quo** are set out in Table 10 below. The time and costs that might be incurred by the PSO are not included.

Table 10: Recurring Time and Costs for Status Quo

	Status Quo	
No. of Affected Trading Days per Incident	**Effort Estimates[22] (Man hours)**	**Cost Estimates**
1	20	$1,162.50
2	23.6	$1,371.75
3	27.2	$1,581

[21] In the past 5 years (from 1 Jan 2011 to 31 Dec 2016), there were 389 dispatch periods with price separation out of the 87,648 dispatch periods (0.444% of the time). Hence, the empirical probability of a dispatch period with price separation **and** Type 5 price revision due to islanding of GFs is 0.00114%.

[22] See Annex 1 for detailed breakdown and explanation of effort required for different number of affected trading days per incident.

For **Option 1**, the recurring effort of 2 man hours and corresponding costs of $116.25 is incurred for the sanity check of the assigned prices for each incident.

One-Off Time and Costs

The breakdown of the estimated one-off implementation time and costs for **Option 1** (updated) and **Option 3** are set out in Table 11 below.

Table 11: Updated Implementation Time and Costs for Options 1 and 3

<table>
<tr><th rowspan="2">Time Estimates</th><th colspan="2">Option 1</th><th colspan="2">Option 3</th></tr>
<tr><th>Effort Estimates (Man weeks)</th><th>Lapse Time (Calendar weeks)</th><th>Effort Estimates (Man weeks)</th><th>Lapse Time (Calendar weeks)</th></tr>
<tr><td>1. Change Requirement Scoping and Analysis</td><td>1</td><td>1</td><td>1</td><td>1</td></tr>
<tr><td>2. MCE Development and Testing</td><td>3</td><td>5</td><td>2</td><td>3</td></tr>
<tr><td>3. User Acceptance Testing</td><td>~~3~~ 7</td><td>4 10</td><td>3</td><td>4</td></tr>
<tr><td>4. Audit</td><td>2</td><td>3</td><td>0</td><td>0</td></tr>
<tr><td>Total Time Required</td><td>~~9~~ 13</td><td>~~13~~ 19</td><td>6</td><td>8</td></tr>
<tr><td>Cost Estimates</td><td></td><td></td><td></td><td></td></tr>
<tr><td>1. Power Systems Consultant Resource/EMC Manpower</td><td colspan="2">~~$36,725~~ $46,025
(Within EMC's budget)</td><td colspan="2">$27,725
(Within EMC's budget)</td></tr>
<tr><td>2. External resource to support</td><td colspan="2">N.A</td><td colspan="2">N.A</td></tr>
<tr><td>3. Audit</td><td colspan="2">$25,000</td><td colspan="2">N.A[23]</td></tr>
<tr><td>Total Additional Cost Required</td><td colspan="2">$25,000</td><td colspan="2">N.A</td></tr>
</table>

Comparison of Total Costs

Using the above estimates, the costs incurred or would have been incurred by the EMC due to the islanded incidents from 1 January 2011 to 31 December 2015 under status quo and Options 1 and 3 are summarised in Table 12 below.

Table 12: Costs Due to Islanded Incidents from 1 Jan 2011 to 31 Dec 2015

Costs	Status Quo	Option 1	Option 3
Recurring	$4,115.25	$348.75	$0
One-off Implementation (Additional)	N.A.	$25,000	N.A.
Total	**$4,115.25**	**$25,348.75**	**$0**

[23] No audit is required since there is no MCE formulation change.

9.4 Conclusion and Recommendation

Both the status quo and Option 1 preserves the locational marginal pricing principle in the SWEM. Although Option 1 more closely aligns with the ex-ante pricing principle in the SWEM as compared to the status quo at a reasonable cost, EMC MO has reiterated concerns with the risks and complexity associated with its implementation. Furthermore, a closer examination of the costs incurred by EMC for the status quo reveals that the recurring costs were low.

EMC recommends that the RCP **support** maintaining the status quo.

10. RCP's Decision at the 89th RCP Meeting

At the 89th RCP meeting held on 6 September 2016, the RCP **by majority vote** **support** maintaining the status quo.

The following Panel member voted to support the proposal to implement Option 3:

1. Mr. Henry Gan (Representative of the EMC)

The following Panel members voted to support maintaining the status quo:

1. Ms. Priscilla Chua (Representative of Generation Licensees)
2. Mr. Marcus Tan (Representative of Generation Licensees)
3. Ms. Grace Chiam (Representative of Generation Licensees)
4. Mr. Daniel Lee (Representative of Retail Electricity Licensees)
5. Mr. Luke Peacocke (Representative of Retail Electricity Licensees)
6. Mr. Dallon Kay (Representative of Wholesaler Electricity Market Trader Licensees)
7. Mr. Lawrence Lee (Representative of the Market Support Services Licensee)
8. Mr. Phillip Tan (Person experienced in Financial Matters)
9. Dr. Toh Mun Heng (Representative of Consumers of Electricity in Singapore)

Annex 1: Breakdown of Effort Required for Status Quo

When an islanded incident is identified, EMC MO will need to work with the PSO and IT to resolve the issue by conducting a MCE rerun. Table 13 outlines the steps to be taken by EMC MO and the corresponding effort required for an islanded incident.

Table 13: Expected Effort & Lapse Time for Status Quo

Step	Details	Expected Effort (Man hours)	Expected Lapse Time (Hours)	Remarks
1	MO to conduct preliminary investigations after detecting the situation during Daily Routine Check	1	2	
2	MO to consult the PSO for a suitable busbar to reconnect the islanded GF to the grid	1	8	PSO is expected to take a day for to get back
3	MO to raise an incident case and ask IT to prepare offline environment for rerun	1	2	
4	IT to prepare the offline rerun environment	2	4	Could take longer if there are unexpected technical issues
5	MO to verify the offline rerun environment by conducting base test runs	1	1	
6	MO to prepare the SQL to change the default/alternate busbar as provided by PSO IT to execute the query	2	2	
7	MO to conduct reruns and summarize the rerun results in the Detailed Investigation report	8	8	
8	MO to get the Detailed Investigation report approved by the manager	2	4	
9	IT to port-over the rerun results to production environment	1	2	Could take longer if there are unexpected technical issues
10	MO to verify the ported-over results and issue price revision and price finalization notices.	1	3	
Total		**20**	**36**	

In total, it would take about 20 effort man-hours to resolve an islanded incident that has affected one trading day or less. While Table 13 states that it would take 36 lapse hours, conducting some steps in parallel would reduce the lapse time to around 30 hours.

The expected effort for Steps 1 to 6 does not change with the number of affected trading days (for the same incident). For Steps 7 to 10, the expected effort will increase by an estimate of 30% with each additional affected trading day (for the same incident).