Energy Market Company

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SUBJECT	:	**MODELING OF MULTI-UNIT CONTINGENCY RISK**
FOR	:	**DISCUSSION & DECISION**
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Executive Summary

During the rule change work plan consultation exercise in 2007, the PSO raised concerns about insufficient reserve being procured against some types of contingency events that could cause the system to lose multiple generation facilities at the same time. This could potentially result in interruption of non-dispatchable load.

This paper presents

1) PSO and EMC's conceptual proposal to modify the existing reserve regime to address this system security concern of the PSO;
2) the results of the cost-benefit analysis of the proposal and
3) PSO and EMC's response to the market participants' comments on the conceptual proposal and the results of the cost-benefit analysis.

The RCP discussed the conceptual proposal over a number of RCP meetings and by majority vote decided **not to support** the proposal.

1 Introduction

This paper presents PSO and EMC's conceptual proposal to model multi-unit contingency (MUC) risk into reserve requirement setting and the resultant reserve cost allocation in the Singapore Wholesale Electricity Market (SWEM).

2 Existing Regime for Reserve Requirement Setting and Reserve Cost Allocation

2.1 How Reserve Requirement is Currently Set

Currently, sufficient reserve is procured to cover the loss of any primary contingency unit (PCU), i.e. generation registered facilities (GRFs) dispatched to provide energy. Hence reserve requirement is based on the single largest scheduled quantity of a GRF. Transmission contingencies are not considered because the transmission system in Singapore was considered to have significant capacity and redundancy at the time the market was designed[1].

The risk of each PCU is calculated as follows (please refer to D17.1 of Appendix 6D of Chapter 6 of the Market Rules)

Raw Calculated Risk[2]= Scheduled Generation of the PCU
─ Power System Response
+ Scheduled Effective Reserve of the PCU
+ (Sum of Scheduled Generation and Scheduled Effective Reserve of all SCU[3])

where
Power System Response[4] = (Estimated Intertie Contribution x Acceptable Frequency Deviation x Estimated Load Damping x System Load)
─ (Estimated GT Output Damping x Total GT Generation)

From the above formulae, it can be seen that the largest determinant of the size of Raw Calculated Risk is the scheduled generation/reserve level of each PCU (i.e. GRF).

The reserve requirement would be set to cover the largest single risk among all PCUs. Additionally, the PSO has the discretion to adjust the reserve requirement by setting the Risk Adjustment Factors (RAF)[5]. Thus:

Reserve requirement = Largest Raw Calculated Risk × Risk Adjustment Factor

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[1] PHB Hagler Bailly's Memorandum on Wholesale Market Design, 2 August 2000

[2] The same formula is used for the calculation of Raw Calculated Risk for all three categories of reserves (Primary, Secondary and Contingency reserves). But the parameters (i.e. power system response and scheduled reserve) would be different for each category.

[3] SCU means Secondary Contingency Unit. There are currently no SCUs in the SWEM. No SCU will be considered in this study.

[4] Acceptable Frequency Deviation and Estimated GT Output Damping are set different for each category of reserve, Thus, the power system response calculated would be different for each category of reserve.

[5] Currently the RAF is normally set at 1.0 for primary and secondary reserve and 1.5 for contingency reserve.

2.2 Allocation of Reserve Cost ─ Modified Runway Method

The design of the SWEM is based on the principle of economic efficiency[6]. Among other things, this calls for "those that cause costs to face the costs they cause". This is known as the causer-pays principle. By allocating costs to parties that are best able to manage them, efficient cost allocation is achieved because these parties will be incentivised to minimise cost.

Reserve is procured to cover the risk of the loss of any single GRF. If each GRF is totally reliable in providing the energy as scheduled, then there would be no need for reserve. Hence, the need for reserve is created by the GRFs. Adopting the causer-pays principle, total reserve cost is allocated to GRFs that are scheduled to provide energy.

Total reserve cost is the sum of the products of the reserve requirement and reserve price for all three categories of reserves. Each GRF is to bear a percentage of the total reserve cost called the reserve responsibility share (RRS). The RRS of a GRF is calculated using a modified runway formula. The rationale of the modified runway formula is:

a) A GRF needs to pay for its share of the reserve procured to cover the quantum of the risk that it creates; and

b) the higher the probability of failure of a GRF (ie the standing probability of failure of the GRF), the higher the proportion of the cost it should bear .

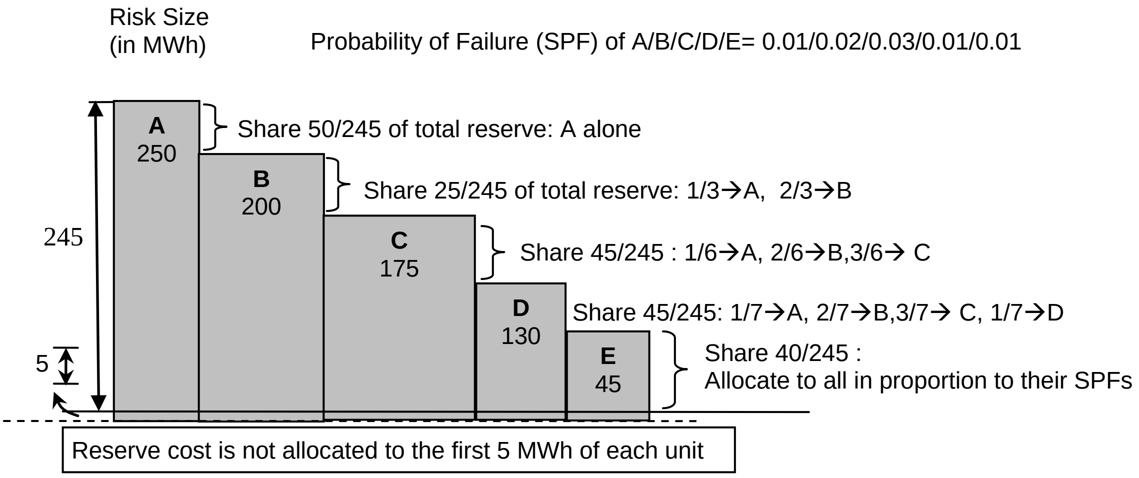
Figure 1 illustrates how reserve cost is allocated to each GRF according to the risk it creates and its standing probability of failure (i.e. SPF).

In Figure 1, each block represents the risk associated with one contingency event, i.e. the tripping of a GRF. The height of a block represents the size of the contingency event in MWh. The width of the block represents the likelihood of occurrence of the contingency event. With the size and likelihood of occurrence known for each contingency event, the share of reserve cost that each contingency event should bear can then be calculated.

In summary, the key elements in the modified runway formula are:

- **Contingency events to be considered**. This determines how many blocks are to be included in the cost allocation.
- **Causers of each contingency event.** This determines the party/parties that is/are to bear the cost attributable to a contingency event.
- **Size of each contingency event**, i.e., the height of each block.
- **Likelihood of occurrence for each contingency event**, i.e., the width of each block.

[6] PHB Hagler Bailly's Memorandum on Wholesale Market Design, 2 August 2000.



Calculation of RRS

RRS of A =	50/245 + 25/245 x 0.01/(0.01+0.02) + 45/245 x 0.01/(0.01+0.02+0.03) + 85/245 x 0.01/(0.01+0.02+0.03+0.01) + 40/245 x 0.01/(0.01+0.02+0.03+0.01+0.01)	=0.3387
RRS of B =	25/245 x 0.02/(0.01+0.02) + 45/245 x 0.02/(0.01+0.02+0.03) + 85/245 x 0.02/(0.01+0.02+0.03+0.01) + 40/245 x 0.02/(0.01+0.02+0.03+0.01+0.01)	=0.2692
RRS of C =	45/245 x 0.03/(0.01+0.02+0.03) + 85/245 x 0.03/(0.01+0.02+0.03+0.01) +40/245 x 0.03/(0.01+0.02+0.03+0.01+0.01)	=0.3017
RRS of D =	85/245 x 0.01/(0.01+0.02+0.03+0.01) +40/245 x 0.01/(0.01+0.02+0.03+0.01+0.01)	=0.0700
RRS of E =	40/245 x 0.01/(0.01+0.02+0.03+0.01+0.01)	=0.0204
Sum		=1.0000

Figure 1 Modified Runway Reserve Cost Allocation

Currently, contingency events included in the reserve cost allocation are only restricted to the tripping of individual GRFs, i.e., one block represents one GRF's tripping. Reserve cost is allocated to the owner of individual GRF. The risk size of the contingency is represented by the scheduled energy quantity (in MWh[7]) for every dispatch period of each GRF and the likelihood of occurrence is the standing probability of failure (i.e. SPF) of each GRF.

3 Risks Identified by the PSO under Three Scenarios

On top of the tripping of individual GRFs, the PSO has identified three types of scenarios under which other contingency events need to be factored into reserve calculation. When such contingency events occur, the system could lose more than one GRF at the same time. These contingency events are called multi-unit contingency events in this paper.

[7] The scheduled energy for a GRF for a dispatch period (1/2 hour) is expressed in MW. For the calculation of RRS, the risk size of each GRF is calculated with its scheduled energy (in MW) times half an hour (1/2 hour).

3.1 Type 1: Two or more GRFs within the same Power Station that are co-dependent

During normal operation, if more than one GRF trips due to a single element/functional system failure, the PSO will consider the tripped GRFs to be co-dependent (ie aggregate the generation scheduled from these GRFs when considering the risk they pose to the system) until rectification works/re-test is conducted to address the cause of the multi-unit tripping.

When a group of GRFs are identified as codependent, it is considered that the tripping of any one of these GRFs may lead to the loss of generation from all the remaining co-dependent GRFs in the group.

3.2 Type 2: Only one transmission facility connects two or more GRFs within the same Power Station to the grid

This scenario describes the situation where two or more GRFs within the same power station are connected to the grid through only one transmission facility. If this transmission facility trips, the system will lose all the GRFs connected through it. An example of this contingency event arising is when two GRFs are connected to the grid through two transmission lines and one of these two transmission lines trips or is taken out for maintenance, resulting in only one transmission line connecting the two GRFs to the grid. In such a situation, there is a risk of the simultaneous loss of the two GRFs if the (remaining) transmission line trips.

3.3 Type 3: Risks associated with Gas supply which may lead to disruption of gas supply to more than one GRF.

If there is a disruption to gas supply, the system may lose multiple gas-fired GRFs that are supplied by the same pipeline. A gas supply disruption could be due to a fault in any of the many links in the gas supply line (please refer to Annex 1 for an illustration of the gas transportation system linking to a GRF). Among others, an outage at the Onshore Receiving Facility (ORF), metering facilities or receiving facilities could each result in disruption of gas supply to multiple GRFs.

For GRFs served by two gas pipelines, a multi-unit contingency event would arise under the following three situations:

a) When the diesel system or hot-switching capability is on maintenance or not available and one of the two gas pipelines is not supplying.

   In this situation, if there is a failure at the ORF or the upstream portion of the gas pipeline, gas supply would be disrupted even if both streams within the ORF are effective (i.e. one is on duty while the other is on standby). Without the ability to switch to an alternate gas or diesel system, these GRFs are considered part of a multi–unit contingency event because they could trip concurrently.

b) When the gas metering facility at the power station is on single stream operation and one of the two gas pipelines is not supplying.

c) When the gas receiving facility at the power station is on single stream operation and one of the two gas pipelines is not supplying.

Under situations b) and c), if there is any failure in the remaining stream of the gas metering facility or receiving facility, which are normally very close to the GRFs, there would be insufficient time for the GRFs to perform a hot switch to their diesel system. Served by only one of two gas pipelines, they are considered part of a multi-unit contingency event because as they could trip concurrently.

Similarly, for GRFs served only by one gas pipeline, a multi-unit contingency event arises under the following three situations:

d) When the diesel system or hot-switching capability is on maintenance or not available.

In this situation, if there is a failure at the ORF or the upstream portion of the gas pipeline, gas supply would be disrupted even if both streams within the ORF are effective (i.e. one is on duty while the other is on standby). Without the ability to switch to an alternate gas or diesel system, these GRFs are considered part of a multi–unit contingency event because they could trip concurrently.

e) When the gas metering facility at the power station is on single stream operation.

f) When the gas receiving facility at the power station is on single stream operation.

Under situations e) and f), if there is any failure in the remaining stream of the gas metering facility or receiving facility, which are normally very close to the GRFs, there would be insufficient time for the GRFs to perform a hot switch to their diesel system. Served by only one pipeline, they are considered part of a multi-unit contingency event because they could trip concurrently

3.4 Problem Definition

From the descriptions above, it can be seen that the system may lose more than one GRF should any of the following multi-unit contingency events occur:

- simultaneous/consecutive tripping codependent GRFs within the same power station (type 1 scenario);
- forced outage of the only transmission facility that connects the GRFs within the same power station to the grid (type 2 scenario);
- disruption of gas supply to multiple GRFs (type 3 scenario)

As reserve is currently only procured to cover single GRF contingencies, the system would not have procured sufficient reserve for any multi-unit contingency events.

4 Proposed Solution

To address the system security concern over multi-unit contingency events, the reserve requirement-setting regime has to consider the risks associated with the multi-units contingency events.

4.1 Reserve Requirement Modeling in the Market Clearing Engine (MCE)

The proposal is to introduce "multi-unit contingency groups", whose risks will be calculated and factored into the calculation of reserve requirement when needed. GRFs that are vulnerable to any one of the multi-unit contingency events will be grouped together into a combined risk-setter. Table 1 below proposes how GRFs should be grouped together under each of the three types of scenarios described in section 3.

Table1 Multi-unit Contingency Groups under Different Scenarios

Scenario Type	**GRFs to be grouped into one multi-unit contingency group**
Type 1	The two or more codependent GRFs within the same power station identified by the PSO
Type 2	All GRFs within the same power station that are connected to the grid through only one transmission facility
Type 3	All GRFs identified by the PSO that could be lost due to gas supply disruption.

The risk of any multi-unit contingency group would be determined as follows:

Raw Calculated Risk of a Multi-unit Contingency Group =
Sum of Scheduled Generation of all GRFs within the group
─ Power System Response
+ Sum of Scheduled Effective Reserve of all GRFs within the group

The reserve requirement would then be set sufficient to cover the risk of any GRF and any multi-unit contingency event which is activated i.e.

Reserve requirement = Largest Raw Calculated Risk among all GRFs and Multi-unit Contingency Groups × Risk Adjustment Factor

4.2 Trigger-based Mechanism

Multi-unit contingency groups would be used in the MCE's reserve calculations only upon activation by the PSO. The activation criteria for each type of multi-unit contingency event are illustrated in Table 2.

Table 2 Activation Criteria for Each Type of Multi-Unit Contingency Event

Multi-unit Contingency Scenario	Multi-unit Contingency Considered	Activation Criteria	Pre-event/Post-event activation
Type 1 -Risk of multiple tripping of co-dependent GRFs	Simultaneous/Consecutive Tripping of Multiple co-dependent GRFs within the same power station	Forced outage of more than one GRF due to single element/functional system failure	Post
Type 2 - Transmission Risk	Tripping of the only transmission facility connecting multiple GRFs within the same power station to the grid	When there is only one transmission facility connecting multiple GRFs to the Grid due to: a) maintenance work carried out by Genco at the	Pre

Multi-unit Contingency Scenario	Multi-unit Contingency Considered	Activation Criteria	Pre-event/Post-event activation
		switch house; and/or b) maintenance work carried out by SPPG on the transmission line or grid substation	
		When there is only one transmission facility connecting multiple GRFs to the Grid due to: a) failure of Gencos' substation equipment; and/or b) failure of transmission line/equipment	Post
Type 3 -Gas supply risk	Outage in ORF or any place upstream of the gas supply resulting in loss of multiple GRFs	When the GRF has only one gas pipeline (or has two pipelines but one is not available) and the diesel system or hot-switching capability of the GRF is on maintenance/not available.	Pre
	Outage in metering facility at power station resulting in loss of multiple GRFs.	When the GRF has only one gas pipeline (or has two pipelines but one is not available) and the gas metering facility at the power station is on single stream operation.	Pre
	Outage in receiving facility at power station resulting in loss of multiple GRFs.	When the GRF has only one gas pipeline (or has two pipelines but one is not available) and the receiving facility at the power station is on single stream operation.	Pre

The PSO will activate one or more multi -unit contingency groups when required.
For each multi-unit contingency event that the PSO activates, the following information must be specified:

- The type of multi-unit contingency event being activated, i.e. type 1, 2 or 3.
- The identities of GRFs in every multi-unit contingency group that is activated. This information is required to determine the size of the multi-unit contingency event. It also affects reserve cost allocation.

- The dispatch period when the multi-unit contingency event is to commence and end (if known).

The PSO may activate one or more multi-unit contingency events when required. Upon activation by the PSO, the EMC will, for each type of multi-unit contingency event, apply the relevant multi-unit contingency groups in the MCE for the specified dispatch periods (as advised by PSO).

5 RESERVE COST ALLOCATION – DERIVING THE RRS

This section presents the reserve cost allocation methodology proposed by EMC for each of the three types of multi-unit contingency events.

5.1 Type 1: Two or more GRFs within the same Power Station that are co-dependent

The following changes to the modified runway formula are recommended:

- **Contingency events to be considered:** In this scenario, it is considered that the tripping of any GRF within the multi-unit contingency group will always[8] lead to the tripping of rest of the GRFs within the group. The contingency event to be considered is the tripping of any one of the codependent GRFs within the group. Such tripping events are already considered in the existing regime. Thus, there would be no change to the number of blocks to be considered in the reserve cost allocation.

- **Causer of each contingency event**: the owner of each GRF pays for the reserve cost allocated to the two (or more) codependent GRFs.

- **Size of each contingency event**. For co-dependent GRFs, the tripping of either one would result in the loss of two (or more) units. It follows that the size of each co-dependent units should be the sum of energy scheduled for the two (or more) co-dependent units.

- **Likelihood of occurrence**: The existing SPF of the co-dependent units will be used. This is based on the assumption that the two codependent GRFs have always acted independently before this scenario is activated. Thus, their individual SPF should correctly reflect the likelihood of tripping of each GRF[9].

Figure 2 shows the proposed changes to the modified runway formula under this scenario. It extends the example from Figure 1 assuming that C and D are co-dependent GRFs.

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[8] This may be an over estimate of the likelihood that all co-dependent GRFs in a group trip simultaneously if it is considered that this likelihood is better represented by the actual frequency of simultaneous tripping. We would then consider the simultaneous tripping of all co-dependent GRFs in a group as a separate contingency, in addition to the tripping of individual GRFs in the same group. In this case, we would need the historical record of simultaneous tripping of the co-dependent GRFs in order to calculate the group's SPF. This record is currently not available.

[9] This is correct the first time this scenario is activated. However, when type 1 scenario is activated, we must be careful in the calculation of the SPFs of the two codependent GRFs. If any codependent GRF (say A) trips and cause the other GRF (say B) to trip, then only the SPF of GRF A should be increased.

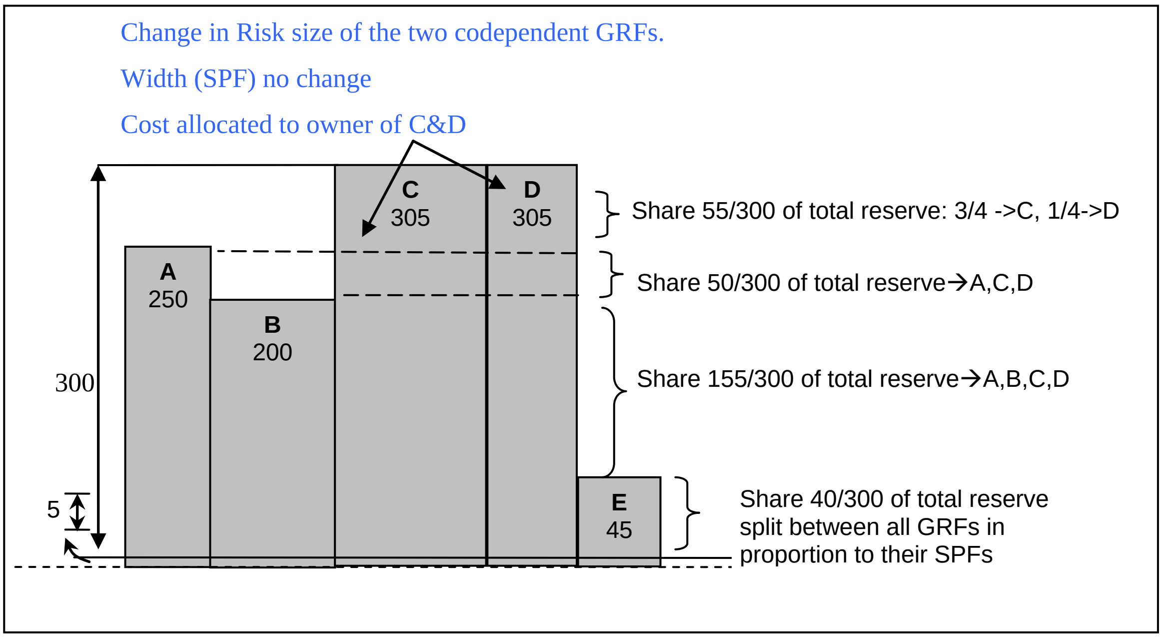


Figure 2 Type 1 Multi-Unit Contingency (Co-dependent GRFs Risk)

5.2 Type 2: Only one transmission facility connects two or more GRFs within the same Power Station to the grid

The following changes to the modified runway formula are recommended:

- **Contingency events to be considered:** The outage risk of the only transmission facility that connects the GRFs within the same power station to the grid, must be included in the reserve cost allocation.
  The outage of the remaining transmission facility may be caused by
  a. Failure of Transmission Licensee (TL)'s equipment only;
  b. Failure of Genco's equipment only; or
  c. Failure of either TL's equipment or Genco's equipment.

  As these contingencies are not considered under existing regime, thus new block(s) should be created in the modified runway formula to represent the transmission risk caused by TL and/or Genco respectively, i.e.
  - in situation (a) above, one new block should be created to represent the risk caused by failure of TL's equipment only;
  - in situation (b) above, one new block should be created to represent the risk caused by failure of Genco's equipment only; and
  - in situation (c) above, two new blocks should be created to represent the risk caused by failure of TL's equipment and Genco's equipment;

  There would be no change to existing blocks for each GRF (including the affected GRFs in the scenario contingency events) as the risk of the tripping of these GRFs still exists.

- **Owner (causer) of each contingency event:** For the new block(s) created to represent the transmission facility outage event, the TL and/or the Genco should bear the cost allocated to their respective blocks.

- **Size of each contingency event:** the risk size for the transmission facility outage event will be the sum of the energy scheduled from all GRFs connected to this transmission facility.

- **Likelihood of occurrence:** the likelihood of occurrence is the probability of failure of the (only remaining) transmission facility. Information to calculate SPF must be provided by the PSO.

  For the block attributed to the TL, the SPF should be computed as the number of dispatch periods that the transmission facility experiences forced outage caused by failure of TLs equipment divided by the number of dispatch periods that the transmission facility is in operation as reflected in the real-time dispatch schedule.

  For the block attributed to the Genco, to compute the SPF, the number of dispatch periods that the transmission facility experiences forced outage caused by failure of Genco's equipment would be used for the numerator.

  If no records are available, then the SPF(s) should be set to the smallest possible value of 0.001% allowed by the MCE.

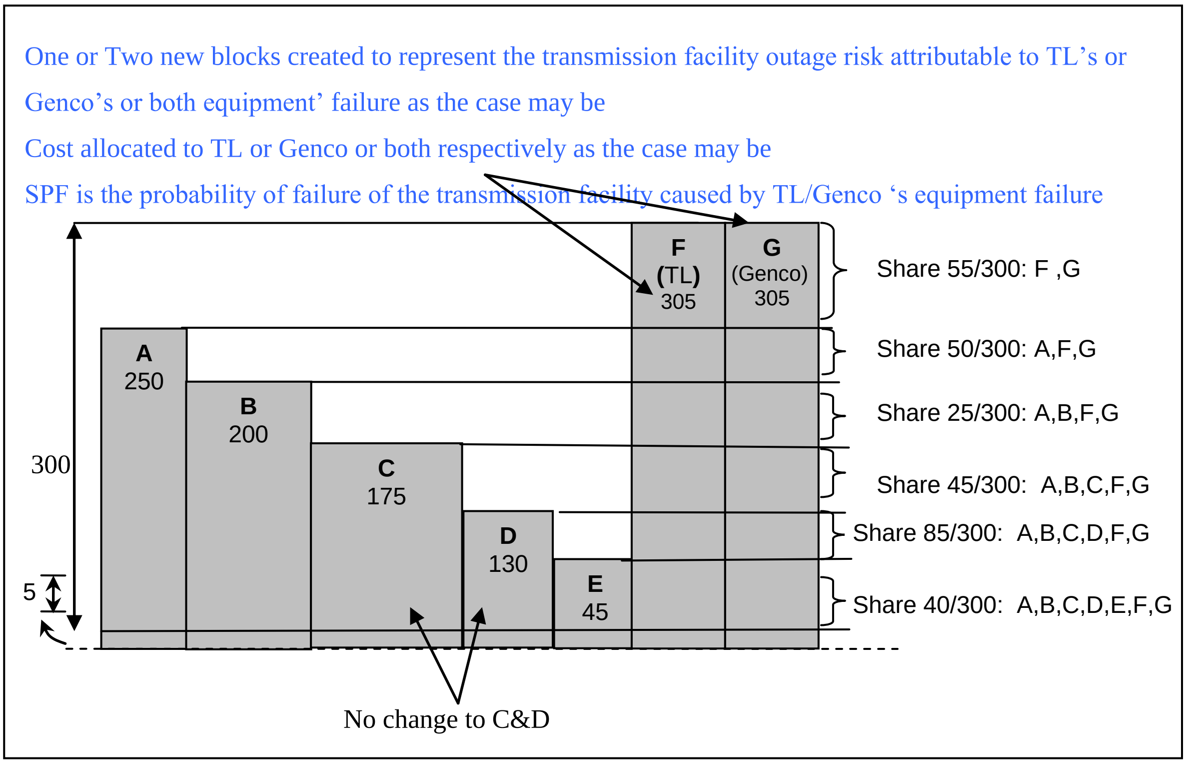


Figure 3 Type 2 Multi-Unit Contingency (Transmission Facility Risk)

Figure 3 shows the changes to the modified runway formula model under the Type 2 scenario. It extends the example in Figure 1 assuming that C and D are the two GRFs connected to the grid through one single transmission facility.

5.3 Type 3: Risk associated with gas supply which may lead to disruption of gas supply to more than one GRF.

The following changes to the modified runway formula are recommended:

- **Contingency events to be considered:** The risk of disruption of gas supply must be included in the reserve cost allocation. A new block should be created for each multi-unit risk group activated under this type. There would be no change to existing blocks of each GRF as the risk of individual GRFs' tripping still exists.

- **Owner (causer) of the scenario contingency event**: As described in Section 3.3, type 3 multi-unit contingency events can be further broken down into these three situations:
  a) Gas disruption due to outage of ORF or the upstream portion of the gas pipeline
  b) Gas disruption due to metering facility outage
  c) Gas disruption due to receiving facility outage

  When the gas disruption risk is due to c) the outage of the receiving facility, which is normally under the control of the Genco (i.e. the owner of the affected GRFs), then the Genco should bear the costs attributable to this risk.

  When gas disruption risk is due to a) outage of ORF or the upstream portion of the gas pipeline, or b) metering facility outage, then the gas supplier/ ORF operator or the gas transporter should be responsible for such gas disruption contingencies. However, these parties are not market participants in the SWEM so it is not possible to allocate reserve costs to them. Thus, it is proposed that the owner(s) of the affected GRFs bear the cost. We discuss this in more detail in section 5.3.1.

- **Size of each contingency event:** the risk for the disruption of gas supply event will be the sum of the energy scheduled from all the affected GRFs in the multi-unit contingency group identified by the PSO.

- **Likelihood of occurrence for each contingency event:** As the case may be, the SPF should be calculated based on historical tripping records of disruption of the gas supply resulting from a) outage at ORF or any place upstream; b) metering facility outage and c) receiving facility outage respectively. These should be calculated as the number of periods of tripping due to gas disruptions divided by the number of periods that gas is supplied from the ORF/metering facility/receiving facility respectively. If no records are available, then SPF(s) should be set to the smallest possible value allowed by the MCE, i.e. 0.001%.

An illustration is given in Figure 4. It assumes that C and D are the two GRFs grouped together under this scenario.

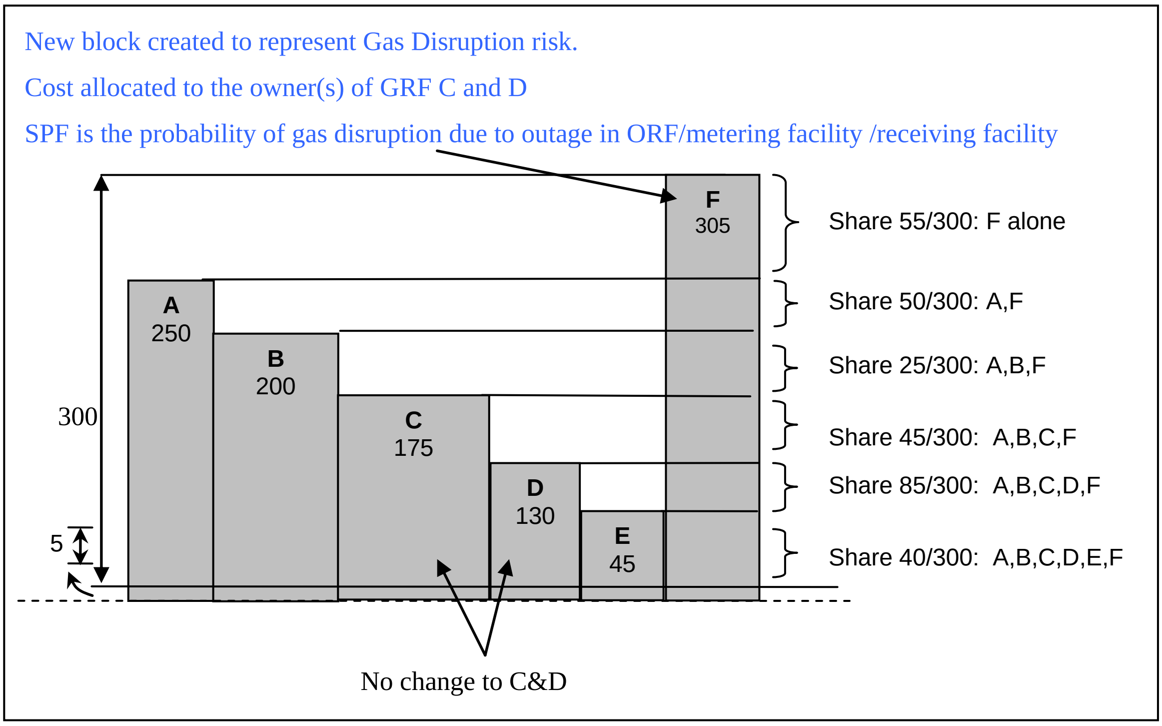


Figure 4 Type 3 Multi-Unit Contingency (Gas Disruption Risk)

5.3.1 Issues with Reserve Cost Allocation

When this multi-unit contingency event is due to a) outage at the ORF or upstream portion of the gas pipeline or b) outage at the metering facility, it follows from the causer-pays principle that the gas supplier/ORF operator or the gas transporter should bear the reserve costs. Hence in principle, the cost allocated to the multi-unit contingency group (i.e., the RRS calculated to block F in Figure 4) should consequently be borne by them. However, these parties are not market participants in the SWEM and are not subject to the Market Rules. We are hence not able to allocate the reserve cost to them.

As a second-best solution, we consider that the Genco as the owner(s) of the affected GRFs should bear the reserve cost. We consider that the owner(s) of the affected GRFs is the next best party that is able to manage this risk.

Table 2 stated that the activation of Type 3 multi-unit contingency event depended on the following conditions:

1) Whether the GRF has an alternative gas pipeline;
2) Whether the diesel system or hotswitching capability of the GRF is available;
3) Whether the metering facility is operating on multiple streams;

If both conditions 1) and 2) or both conditions 1) and 3) are not met, then Type 3 multi-unit contingency event will be activated.

While the Gencos do not have direct control of the availability of the equipment at the ORFs and metering facilities, they are nevertheless capable of taking some measures to manage such risks. For instance, the Gencos can coordinate with the gas suppliers and gas transporters such that the gas pipelines, the metering facilities and the diesel systems would not be on maintenance at the same time. Those currently served by only one gas pipeline can also consider being served by an additional gas pipeline. They can also reduce the risk by adjusting the output level of their generation facilities.

Therefore, charging the reserve cost to owners of GRFs has the benefit of giving them the incentive to find efficient solutions that ensure the continuity of electricity supply during a gas disruption. On these grounds, we suggest that the Gencos, as owners of the affected GRFs, be allocated the reserve costs.

5.3.2 Reserve Cost Allocation among GRFs within a Multi-unit Contingency Group

When the GRFs in the multi-unit group do not all belong to a same Genco, the cost should be allocated to each GRF in proportion to the scheduled energy of each GRF within the group. The size of a multi-unit contingency group is determined by the sum of scheduled energy of all GRFs within the group. Each MWh of scheduled energy of any affected GRF contributes to the risk of such multi-unit contingency. Thus each MWh of scheduled energy should be allocated an equal share of the reserve cost. It follows that the reserve cost allocated to a multi-unit contingency group should be allocated to the GRFs within this group in proportion to the scheduled energy of each GRF.

In the example in Figure 4, if GRF C and D do not belong to the same Genco, the reserve cost allocated to block F will then be distributed to owner of GRF C and owner of GRF D respectively in proportion to the energy scheduled from GRF C and GRF D. This will add to the share of the reserve cost that has been allocated to GRF C and GRF D in the calculation of the RRS for GRF C and GRF D used for settlement.

Similarly, in Type 2 scenario, the reserve cost allocated to the multi-unit contingency group that is attributable to the Genco, (i.e. block G in Figure 3) can also be distributed to the GRFs within the group (i.e. GRF C and D) in proportion to the scheduled energy and reflected in the RRS of individual GRFs.

5.4 Information required for calculation of RRS

The Standing Probability of Failure (SPF) is required for the calculation of the RRS of each GRF or multi-unit contingency group. The existing SPFs of GRFs are calculated using their most recent tripping record of up to one year. To be consistent with this, the SPFs for multi-unit contingency groups should also be calculated well in advance of their activation. The PSO should, as far as possible, identify possible multi –unit contingency groups in advance so that EMC can keep a record of the SPFs of all likely multi-unit contingency groups.

EMC would also require the PSO to provide relevant information needed to compute the SPF of every multi-unit contingency group under each type of scenarios. More details are yet to be finalised between PSO and EMC. These will be done if the RCP support the implementation of MUC.

Also, a reasonably advance notice should be given to market participants to respond when the PSO activates any multi-unit contingency.

6 Industry Consultation

Sembcorp Cogen, Keppel Merlimau Cogen, Senoko Power, Power Seraya and SP PowerAssets have provided their comments on this conceptual proposal. Among other comments, the market participants requests

- Some form of cost-benefit analysis (CBA) should be conducted. The materiality of the MUC risk and the benefit of the proposal should be quantified. In response to this, EMC has proposed a CBA methodology and subsequently performed a CBA. Please refer to section 7 of this paper for the methodology and the results of the CBA.

- Clarity on the processes of identifying the MUC risk. For this, the conditions under which the PSO can activate a MUC are clearly described in section 4.2 of this paper. These conditions will be set out in the market rules. PSO and EMC will work on the detailed procedures if the RCP recommends the implementation of MUC.

PSO and EMC's response to each market participant's comments is shown in Annex 3.

At the 48th RCP meeting, the RCP discussed this proposal. Mr Chan Hung Kwan (representative of TL) commented that TL is operated under a regulated regime. Its regulated revenue does not take into account the wholesale electricity market cost. Thus, TL should not bear any wholesale electricity market cost. Mr Chan requested for clarity from EMA on whether the reserve costs arising from the proposal should be charged to the TL.

The RCP sought EMA's opinion on this. EMA is of the view that
- whether or not Transmission Licensee should bear any reserve cost as proposed by EMC depends on whether the EMC's proposal conforms to the "causer-pays principle";
- In any case, SPPA should be subject to the market rules as section 2 of the Electricity Act defines "market participant" to include the transmission licensee;
- the market rules have the effect of a contract between each "market participant" and the Market Company

At the 49th RCP meeting, Mr Chan reiterated his reservation on the proposed reserve cost allocation for Type 2 MUC. He explained that if PSO can identify the Type 2 MUC situation, they should inform TL. TL, having fulfilled its obligation of "N-1" under the Transmission Code, will then request the relevant genco to pay for a third (or additional) transmission line. If the relevant genco agrees to do so, the Type 2 MUC situation will no longer exist. If the relevant genco refuses to pay for the third transmission line, the causer will be the relevant genco in the Type 2 MUC situation. The reserve cost should then be allocated to the genco instead of the TL as proposed in the paper.

EMC is however of the view that the reserve cost is allocated to TL only when the Type 2 MUC risk is caused by the outage of the TL's equipment (for example, maintenance of the transmission line carried out by the TL). In such situations, TL is the causer of the Type 2 MUC risk and should bear the associated reserve cost. This is consistent with the "causer pays" principle.

7 Cost Benefit Analysis

7.1 CBA Methodology

EMC published its proposed CBA methodology (please refer to Annex 4). In the CBA methodology paper, it was established that the benefit of the proposal would be the improved system reliability. Improved reliability would mean reduced likelihood of load shedding when MUC occurs. It is measured by the change (reduction) in Expected Energy Not Served (EENS) multiplied by the Value of Lost Load (VoLL). The costs of the proposal would be the cost incurred to meet the additional reserve requirement when a MUC is identified and the cost of implementing the MUC method. The cost incurred to meet the additional reserve requirement when a MUC is identified would be measured by the increase in the short run cost, which is, the change in cost of production of energy, reserve and regulation. By comparing the original schedules of past MUC incidents with the schedules generate using MUC method, the change in production cost and benefit of the MUC method can be determined. Also, it was suggested that the most recent calendar year (i.e. 2007) be used as the study period.

In response to EMC's proposed CBA methodology, PSO proposed to have a comparison between the RAF and MUC Method as in the absence of the MUC method, the PSO may have to adjust the RAF to a higher level to ensure sufficient reserve is procured. A more objective way would be to do an analysis of the cost and benefits of the MUC method compared with the RAF method. The comparison would "provide clearer and meaningful assessment of the two methods".

To support its stand further, PSO provided a set of slides (please refer to Annex 5) which was presented to the industry twice. The slides showed clearly that the proposed MUC method is:

- more targeted (to the causer rather than across the board)
- it is more dynamic and not static as in the case of the RAF method
- it addresses the system security concerns

PSO also proposed that the study period should be extended to include past incidents before or after 2007 so as to be as inclusive as possible.

EMC agreed to PSO's suggestion to use the actual periods where PSO identified that historical MUC risk have existed. On PSO's suggestion to compare against the RAF method, EMC's view is that simulation using the RAF method can be conducted for comparison purposes. However, the base for comparison should still be the original schedule that had actually happened during the past MUC incidents. If in the original schedule, RAF were applied to cover the MUC risk, then the effects of the RAF that PSO had applied then would be reflected in the original schedule used to compare against the MUC method in the CBA study. Since RAF were not applied in historical cases used for the CBA study, any subsequent simulation with the RAF method should be used for information only and should not be part of the formal CBA study.

Sembcorp Cogen commented that the CBA study should also look into how the additional reserve requirement increases the cost of production and the spillover effect on consumers in the form of higher energy prices. As explained in section 2.3.3 of Proposed CBA Methodology paper, the change to the energy prices under MUC method will be included to show how consumers could be affected.

Please note that the results of the RAF method and the impacts on the energy prices are included in this paper for additional information only and should not be considered as part of the CBA.

7.2 CBA Results

Based on the CBA methodology described in Annex 4, EMC has performed the analysis for a study period of year 2003 to 2008. During this study period, three past MUC cases were provided to EMC by the PSO for the CBA study. A description of these cases is summarised in Table 3.

Table 3 Historical MUC Cases

	Type 1 Case		Type 2 Case		Type 3 Case	
Date	Late May – Early June of 2003 l		May 2008		Dec 2006 – Jan 2007	
Duration	7.5 days		14.5 days		21.3 days	
	MUC Method[10]	RAF method[11]	MUC Method	RAF method	MUC Method	RAF method
	Two units of an aggregate capacity of 785MW to be grouped into a MUC group	Expected RAF (PRI)=2.24 (SEC)=2.24 (CON)=2.15	Two units of an aggregate capacity of 490MW to be grouped into a MUC group	Expected RAF (PRI)=1.4 (SEC)=1.4 (CON)=1.34	Two units of an aggregate capacity of 730MW to be grouped into a MUC group	Expected RAF (PRI)=2.09 (SEC)=2.09 (CON)=2
	Prob. of failure (PoF) is the sum of PoF of the two individual units		0.001% (As we receive no information on this, SPF(s) used is set to the smallest possible value of 0.001% allowed by the MCE)		0.001% (As we receive no information on this, SPF(s) used is set to the smallest possible value of 0.001% allowed by the MCE)	

[10] MUC method means the schedules are recomputed with the MCE modified to include the MUC constraint as described in Section 4.1 of this paper.

[11] RAF method means that the schedules are recomputed with the existing MCE and changing the RAF to the expected RAF values set by PSO.

Following the procedures as described in section 2.4 of Annex 4 "Proposed CBA Methodology", EMC has recomputed the schedules with the modified MCE for each dispatch period of the three cases. Similarly, another set of schedules were recomputed by adjusting the RAF to the expected RAF set by PSO.

EENS and Cost of Production are calculated for the base scenario, MUC method scenario and RAF method scenario. By comparing the Cost of Production and EENS in the base scenario with that in the MUC method scenario and RAF method scenario, the increase in Cost of Production and reduction in EENS is derived, which is shown in Table 4.

Table 4 Comparison of Costs and Benefits

	2003 (Type 1)		2006(Type 3)		2008 (Type 2)	
	MUC	RAF(for information only)	MUC	RAF(for information only)	MUC	RAF(for information only)
Increase in Cost of Prod	$3,074,338	$17,005,663	$28,867,075	$253,897,582	$2,376,082	$7,790,7362
Reduction in EENS	342.79MW	344.05MW	1.51MW	2.04MW	0.54MW	0.65MW
Benefit (VoLL x ΔEENS)[12]	$1,565,519	$1,571,486	$8,415	$11,354	$3,389	$4,089
Cost per MWh of EENS prevented	$8,969 /MWh	$49,421 /MWh	$19,108,033 /MWh	$124,556,985 /MWh	$4,393,758 /MWh	$11,937,560 /MWh

Further, the one-time cost for EMC to implement the proposal is estimated to be in the range of $501,000 to $676,000. A breakdown of the costs is shown in Table 5.

Table 5 EMC's Estimate of Implementation Cost

	EMC internal Effort	External Cost
Requirement Gathering	15% (10.5 man weeks)	
Design	10% (7 man weeks)	
Development	30% (21 man weeks)	$175,000 - $350,000
Testing	30% (21 weeks)	
Audit	5% (3.5 weeks)	$50,000
Implementation	10% (7 weeks)	
Total	70 man weeks (=$276,000)	$225,000 - $400,000

The estimated benefits and costs of the MUC proposal compared with status quo is summarized in Table 6.

[12] The VoLL calculated for year 2003, 2006 and 2008, based on the GDP and annual electricity consumption, is $4,567/MWh, $5,570/MWh and $6,266/MWh respectively. Please refer to Annex 6 for the computation of VoLL.

Table 6 Summary of CBA

	2003	2004	2005	2006	2007	2008	Total Study Period
Cost	$3,074,338	0	0	$28,867,075	0	$2,376,082	$34,317,495
Benefit	$1,629,277	0	0	$8,720	0	$3,475	$1,577,322
Net Benefit	-$1,508,820	0	0	-$28,858,690	0	-$2,372,693	-$32,740,173
Implementation cost(One-time)							$676,000
Total Cost							$33,416,173

7.3 Impacts on Prices/Dispatch Schedules

Other than the changes in the cost of production and the EENS as shown in the CBA results under section 7.2 above, changes in the prices and dispatch schedules are also observed. Please see Table 7.1-7.6 below for the comparison of the prices and dispatch schedules under different scenarios.

These are provided for additional reference, as the MUC method could affect the costs incurred by the market participants in procuring energy, reserves and regulation in the real time markets. However these costs are not to be compared with the costs and benefits to determine the CBA results in section 7.2. They are shown here only to provide another perspective for the industry, which is familiar with these costs.

Table 7.1 2003(Type 1) Comparison of Base/MUC case

	Base Average	MUC Average	Average Increase		Max Increase	Min increase
USEP($/MWh)	126.70	227.05	100.34	79.19%	4327.75	-109.19
Pri Res Rqmt (MW)	271.53	383.38	111.85	41.19%	255.73	0.00
Sec Res Rqmt(MW)	290.44	424.74	134.30	46.24%	279.41	-44.94
Con Res Rqmt(MW)	389.55	495.88	106.34	27.30%	344.79	-51.95
Energy Schedule of MUC (MW)	570.19	465.50	-104.70	-18.36%	0.00	-217.50
Pri Res Price($/MWh)	5.81	1,886.61	1,880.79	32352.59 %	4499.85	0.00
Sec Res Price($/MWh)	3.71	50.75	47.04	1267.62%	1695.77	0.00
Con Res Price($/MWh)	29.12	121.34	92.21	316.64%	3473.68	0.00
Reg Price($/MWh)	51.69	153.07	101.38	196.12%	2973.00	0.00

Table 7.2 2003(Type1) Comparison of Base/RAF case

	Base Average	RAF Average	Ave Increase		Max Increase	Min increase
USEP($/MWh)	126.70	1,237.47	1,110.77	876.66%	4380.92	0.12
Pri Res Rqmt (MW)	271.53	422.25	150.71	55.50%	271.01	52.55
Sec Res Rqmt(MW)	290.44	509.10	218.66	75.29%	321.92	88.52
Con Res Rqmt(MW)	389.55	678.06	288.52	74.06%	442.77	36.44
Energy Schedule of MUC (MW)	570.19	512.61	-57.58	-10.10%	190.00	-275.88
Pri Res Price($/MWh)	5.81	2,850.09	2,844.27	48925.95 %	4499.85	40.81
Sec Res Price($/MWh)	3.71	1,246.90	1,243.18	33503.24 %	3999.85	9.39
Con Res Price($/MWh)	29.12	933.70	904.58	3106.13 %	3500.00	0.00
Reg Price($/MWh)	51.69	415.72	364.03	704.24%	2976.00	-1262.42

Table 7.3 2006 (Type 3) Comparison of Base/MUC case

	Base Average	MUC Average	Average Increase		Max Increase	Min increase
USEP($/MWh)	114.13	488.88	374.75	328.34%	4358.96	-32.56
Pri Res Rqmt (MW)	260.65	282.56	192.87	8.40%	320.26	-43.65
Sec Res Rqmt(MW)	261.11	295.96	34.84	13.34%	98.17	-7.09
Con Res Rqmt(MW)	516.95	565.11	48.16	9.32%	130.50	-136.10
Energy Schedule of MUC (MW)	595.76	368.89	-226.87	-38.08%	0.00	-327.53
Pri Res Price($/MWh)	12.28	1,906.35	1,894.07	15425.29 %	4499.87	0.00
Sec Res Price($/MWh)	1.74	137.31	135.57	7813.71 %	3998.20	-2.86
Con Res Price($/MWh)	17.42	233.38	215.97	1240.05 %	3489.47	0.00
Reg Price($/MWh)	496.63	943.66	447.03	90.01%	2994.01	-571.21

Table 7.4 2006 (Type 3) Comparison of Base/RAF case

	Base Average	RAF Average	Ave Increase		Max Increase	Min increase
USEP($/MWh)	114.13	2,634.21	2,520.07	2208.00%	4401.47	0
Pri Res Rqmt (MW)	260.65	374.55	284.86	43.70%	193.30	26.023
Sec Res Rqmt(MW)	261.11	433.46	172.35	66.00%	233.25	76.079
Con Res Rqmt(MW)	516.95	923.93	406.98	78.73%	508.7	75.329
Energy Schedule of MUC (MW)	595.76	499.45	-96.31	-16.17%	75.35	-186.403
Pri Res Price($/MWh)	12.28	4,376.09	4,363.81	35538.77 %	4499.99	634.07
Sec Res Price($/MWh)	1.74	2,885.08	2,883.34	166179.78 %	3999.99	18.8
Con Res Price($/MWh)	17.42	2,801.64	2,784.22	15986.73 %	3499.88	0
Reg Price($/MWh)	496.63	1,815.73	1,319.10	265.61%	2999.01	-129.93

Table 7.5 2008(Type 2) Comparison of Base/MUC case

	Base Average	MUC Average	Average Increase		Max Increase	Min increase
USEP($/MWh)	222.65	276.64	53.99	24.25%	2250.21	-0.68557
Pri Res Rqmt (MW)	186.68	259.42	72.74	38.97%	133.7	1.5
Sec Res Rqmt(MW)	253.88	324.33	70.45	27.75%	135.652	3.225
Con Res Rqmt(MW)	538.58	618.94	80.36	14.92%	182.549	1.8
Energy Schedule of MUC (MW)	450.46	410.60	-39.86	-8.85%	0	-117.99
Pri Res Price($/MWh)	0.08	7.17	7.08	8717.26 %	109.4	-0.01
Sec Res Price($/MWh)	2.25	16.32	14.07	624.77 %	399.32	-102.61
Con Res Price($/MWh)	34.88	93.51	58.63	168.08 %	2422.83	-12.18
Reg Price($/MWh)	61.67	106.36	44.69	72.47%	2235.58	-15

Table 7.6 2008(Type 2) Comparison of Base/RAF case

	Base Average	RAF Average	Ave Increase		Max Increase	Min increase
USEP($/MWh)	222.65	402.80	180.15	80.91%	3462.54	-0.00044
Pri Res Rqmt (MW)	186.68	267.84	81.16	43.48%	114.06	0.362
Sec Res Rqmt(MW)	253.88	360.91	107.04	42.16%	136.21	32.57
Con Res Rqmt(MW)	538.58	709.90	171.32	31.81%	217.95	-13.797
Energy Schedule of MUC (MW)	450.46	443.74	-6.71	-1.49%	36.78	-87.5
Pri Res Price($/MWh)	0.08	4.98	4.89	6023.00 %	51.50	0
Sec Res Price($/MWh)	2.25	105.32	103.06	4577.71 %	3438.14	0.01
Con Res Price($/MWh)	34.88	220.06	185.18	530.86%	2891.92	5.32
Reg Price($/MWh)	61.67	210.13	148.46	240.75%	2697.86	-3.76

7.4 Assumptions and Limitations

It is important to note that there are some assumptions and limitation of this CBA study.

Firstly, the assumptions as elaborated in section 3 of the Proposed CBA Methodology paper (please refer to Annex 4) still hold, i.e.

- VoLL is assumed to be an average economic value (which is annual GDP divided by annual electricity consumption). The actual VoLL could be lower or higher depending on the nature of the load;

- It is assumed that energy not served exactly matches the shortfall in reserve. In reality, the load shedding will occur in blocks. Hence the method could underestimate the loss of load. On the other hand, the actual energy shortage could be smaller due to the system response; and

- All input data used in the simulation runs are assumed to be the same. In reality, it is very likely that Gencos' (especially those whose generators are grouped into any MUC) offers would change, which could significantly change the results.

Secondly, the CBA results obtained in section 7.2 are pertaining to the three historical MUC cases used in the study. The result could vary for different MUC cases, depending on the following factors

- capacity of the generation units grouped in a MUC group;
- likelihood of occurrence of MUC;
- duration of the MUC; and
- frequency of MUC being activated.

7.5 Industry Comments

The CBA results were published (together with the updated concept paper) on 25 Nov 2009 for industry consultation. Keppel Merlimau Cogen, Sembcorp Cogen and Senoko Power have provided their comments. Please refer to Annex 7 for the comments and EMC/PSO's response to them.

7.6 CBA results of a Type 1 MUC case which occurred in May 2010

At the 50th RCP meeting, the RCP requested that a CBA be conducted on a recent Type 1 MUC case that occurred in May 2010, where two commissioning generation facilities had tripped simultaneously. During the period PSO had increased the RAF to increase the reserve requirement to cover this MUC risk.

EMC conducted a CBA study of the MUC method against the base RAF method which was used for real-time dispatch for the recent incident in May, in accordance with the CBA methodology described in Annex 4 and presented the results at the 51st RCP meeting..

The study was conducted for the period 12-17 May 2010, when 2 CCPs with a license capacity of about 370 MW each were identified as Type 1 MUC risk. During this period PSO used the RAF method to increase the RAF for primary reserve for 146 dispatch periods, from the normal primary reserve RAF of 1 to between 1.03 and 1.94.

For the purpose of the CBA study – when the MCE was re-run with the MUC method applied – the RAF for Primary, Secondary and Contingency Reserve was set to the normal RAF of 1, 1 and 1.5 respectively to ensure that the increase in reserve requirements for this Type 1 MUC risk is the result of applying the MUC method only.

The CBA results and impacts on prices and schedules are tabulated in Table 8 and 9 below.

Table 8 CBA results for MUC method against the base RAF method for May 2010 case

Increase in Cost of Production	S$626,852.66
Reduction in EENS	101.36 MWh
Benefit	S$652,370.30
Cost per MWh of EENS prevented	S$6184.25 / MWh
Net Benefit	S$25,517.64

Table 9 Impact on prices and dispatch schedules under MUC method for May 2010 case

	Average (as in Base RAF Method)	Average (w/ MUC method)	Average Increase		Max Increase	Min Increase
USEP ($/MWh)	173.01	190.10	17.09	10%	123.75	-21.24
Pri Res Rqmt (MW)	246.09	290.95	44.86	18%	163.858	-59.185
Sec Res Rqmt (MW)	248.06	367.22	119.16	48%	203.611	0
Con Res Rqmt (MW)	523.17	695.41	172.24	33%	282.076	0
Energy Schedule of MUC (MW)	487.33	461.89	-25.44	-5%	0	-203.67
Pri Res Price ($/MWh)	10.79	29.07	18.28	170%	84.09	-105.16
Sec Res Price ($/MWh)	0.19	62.89	62.69	32702%	166.72	0
Con Res Price ($/MWh)	0.43	13.29	12.86	2957%	52.34	0
Reg Price (S/MWh)	65.55	80.08	14.53	22%	166.21	-25.46

EMC also conducted a simulation for the following two scenarios and compared it with the base RAF method.

A - where MUC method is applied to primary reserve only
(referred to as "Primary-MUC" scenario);

B - where neither MUC method nor RAF Method[13] was applied
(referred to as "No-RAF-No-MUC" scenario).

Please refer to Annex 8 for simulation results for these two scenarios.

8 Conclusion

EMC recommends that the RCP discuss this proposal and the CBA results and decide if they support the implementation of the proposed modeling of MUC in MCE.

9 Decision by the RCP

The RCP discussed the conceptual proposal over a number of RCP meetings. At the 52nd RCP meeting, the RCP by majority vote decided not to support the proposal.

The following Panel member voted **to support** the proposal:

- Kng Meng Hwee (Representative of the PSO)

[13] This means that the RAF for primary, secondary and contingency reserve was set back to the normal 1, 1 and 1.5 in the MCE re-run.

- Dallon Kay (Representative of Wholesale Electricity Market Trader Class)
- Robin Langdale (Representative experience in financial matters)
- Dr. Goh Bee Hua (Representative of Consumers)

The following Panel members voted **not to support** the rule change proposal:

- Kenneth Lim (Representative of EMC)
- Chan Hung Kwan (Representative of Transmission Licensee Class)
- Lawrence Lee (Representative of Market Support Services Licensee)
- Daniel Lee (Representative of Generation Licensee Class)
- Philip Tan (Representative of Generation Licensee Class)
- Luke Peacock (Representative of Generation Licensee Class)

Annex 1 Illustration of the Gas Transportation System Linking to a GRF

Annex 2 Summary of Multi-Unit Contingencies

Annex 3 Responses to Market Participants' Comments

Annex 4: Proposed CBA Methodology

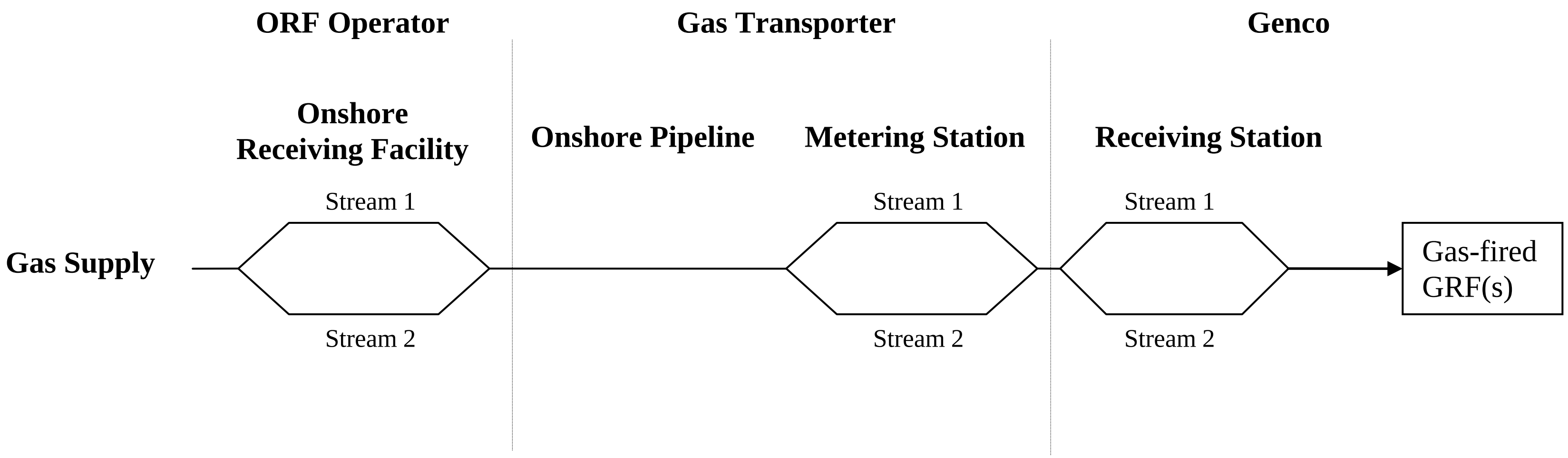
Annex 5 Slides on "Reserve Requirement & Multi-Generating Units Tripping"

Annex 6 Calculation of VoLL

Annex 7 Response to Market Participants' comment to CP 17(with CBA results) published on 25 Nov 209

Annex 8 Simulation results for May 2010 Type 1 MUC case

Annex 1 Illustration of the Gas Transportation System Linking to a GRF



Annex 2 Summary of Multi-Unit Contingencies

Type of Multi-unit Risk	Multi-unit Contingency considered	Activation Criteria	Pre-event/Post-event activation	GRFs grouped together	SPF Calculation	To who the associated reserve cost is allocated
Type 1 -Risk of simultaneous/consecutive tripping of codependent GRFs	Simultaneous/ Consecutive Tripping of Multiple Codependent GRFs within same power station	When there is forced outage of more than one GRF due to single element/functional system failure	Post	Two or more codependent GRFs within the same power station identified as codependent by the PSO	The existing SPF of each GRF within the multi-unit contingency group	The owner of the co-dependent GRFs
Type 2 -Transmission Risk	Tripping of the only transmission facility connecting multiple GRFs within the same power station to the grid due to failure of either 1) Genco's equipment; or 2) TL's equipment; or 3) Both of the above	When there is only one transmission facility connecting multiple GRFs to the Grid due to: • maintenance work carried out by Genco at the switch house; and/or • maintenance work carried out by SPPG on the transmission facility or grid substation	Pre	All GRFs within the same power station that are connected to the grid through the same single transmission facility	1) Number of periods that the transmission facility experience forced outage due to failure of Genco's equipment divided by the number of periods that the transmission facility is	1) Owner of the affected GRFs; 2) TL 3) Both the owner of the affectedGRFs and

Type of Multi-unit Risk	Multi-unit Contingency considered	Activation Criteria	Pre-event/Post-event activation	GRFs grouped together	SPF Calculation	To who the associated reserve cost is allocated
	(both are considered as multi-unit contingency)	When there is only one transmission facility connecting multiple GRFs to the Grid due to: • failure of Gencos' substation equipment; and/or • failure of transmission line/equipment	Post		scheduled to be in operation. 2) Number of periods that the transmission facility experience forced outage due to failure of <u>TL's equipment</u> divided by the number of periods that the transmission facility is scheduled to be in operation. 3) Both of the above need to be calculated	TL
Type 3 -Gas supply risk	Outage in ORF or any place upstream of the gas supply resulting in loss of multiple GRFs	When the GRF has only one gas pipeline (or has two pipelines but one is not available) and the diesel system or hot-	Pre	All GRFs identified by the PSO as a risk to the system due	Number of periods that there are outages in ORF or any place upstream of the	The owner of the affected GRFs

Type of Multi-unit Risk	Multi-unit Contingency considered	Activation Criteria	Pre-event/Post-event activation	GRFs grouped together	SPF Calculation	To who the associated reserve cost is allocated
		switching capability of the GRF is on maintenance/not available.		to probable gas interruption.	gas supply divided by number of periods that there is gas supplied from this gas source	
	Outage in metering facility at power station resulting in loss of multiple GRFs.	When the GRF has only one gas pipeline (or has two pipelines but one is not available) and the gas metering facility at the power station is on single stream operation.	Pre		Number of periods that there is (forced) outage in the remaining stream of the metering facility divided by the number of periods that there is gas scheduled to be supplied from this stream.	The owner of the affected GRFs
	Outage in receiving facility at power station resulting in loss of multiple GRFs.	When the GRF has only one gas pipeline (or has two pipelines but one is not available) and the receiving facility at the power station is on single stream operation.	Pre		Number of periods that there is (forced) outage in the remaining stream of the receiving facility divided by the	The owner of the affected GRFs

Type of Multi-unit Risk	Multi-unit Contingency considered	Activation Criteria	Pre-event/Post-event activation	GRFs grouped together	SPF Calculation	To who the associated reserve cost is allocated
					number of periods that there is gas scheduled to be supplied from this stream.	

Annex 3 Responses to Market Participants' Comments

Comments from Sembcorp Cogen	PSO/EMC's response
1 Introduction The objective of the NEMS is outlined in Chapter 1 of the market rules and is to: • encourage the establishment of efficient, competitive and reliable markets for the wholesale sale and purchase of electricity and ancillary services in Singapore; • facilitate open and non-discriminatory access to the transmission grid; • facilitate competition in the Singapore's electricity industry; and, • ensure that consumers are provided with a reliable supply of electricity at prices that are competitive.	
The proposed concept paper or rule change (PRC) is concerned with increasing the level of security in the NEMS and as per the study cited in the PRC results in an increase in costs. It is therefore important to ensure that: • the costs are borne by those participants best able to manage the associated risks; • the costs are allocated fairly and on the basis of an objective and transparent process; and • the market will continue to function in a manner that is efficient both in the short-term use of resources and in the terms of investment on longer timescales.	PSO: Disagree, the purpose is to ensure that consumers are provided with a reliable supply of electricity at competitive prices.

Comments from Sembcorp Cogen	PSO/EMC's response
This note illustrates that the PRC does not address these issues completely and is thus contrary to the stated objectives of the NEMS for the following reasons: 1 The PRC does not assess the net benefit that an increased level of security would have for the NEMS;	PSO: Consumers will be provided with a more reliable supply of electricity when there is adequate reserve provided by the NEMS to cover identified risk of multi-units tripping.
2 It fails to clarify the decision-making processes that would be used by the PSO and (to a lesser extent) the EMC;	PSO: Details shall be provided at a later stage.
3 Type 1 contingencies are likely to result in inefficient outcomes as a consequence of not modelling the contingencies in the MCE in a way that is consistent with the physical reality for some plant and the cost-allocation modification changes unfairly direct reserve costs toward units that don't contribute to the largest contingency. •	PSO: In what way is the MCE modeling of contingencies inconsistent with physical reality?
4 The specification of Type 2 contingencies is specified in an ambiguous manner and needs to be clarified; and •	PSO: In what way is the specification ambiguous?
5 Type 3 contingencies may result in costs being allocated to the parties that are not able to manage the associated risks. •	PSO: Issue on cost-allocation will leave it to EMC.

Comments from Sembcorp Cogen	PSO/EMC's response
This note discusses these issues in more detail and is structured as follows: • Section 2 discusses issues related to assessing the benefits of the PRC; • Section 3 discusses issues relevant to the PSO's decision-making process; • Section 4 outlines issues with Type 1 contingencies; • Section 5 outlines issues with Type 2 contingencies; and • Section 6 outlines issues with Type 3 contingencies.	EMC: We have responded to each of these 5 points in the following sections.
<u>2. Assessing the Benefits of the PRC</u> 1 In general changes to market rules affect market way in which the market operates and hence affect efficiency. Seemingly well-intentioned rule changes can sometimes create perverse incentives that undermine the operation of the market and/or disadvantage different participants within the market.	PSO: This proposal is so that consumers will be provided with a more reliable supply of electricity, there is no intention to disadvantage any particular MP.
2 As a minimum, any rule change proposal should assess the net benefits of the changes and assess them against the stated objectives of the NEMS	
3 Increased levels of security (as advocated in the PRC) increase the costs of electricity production, reserves and regulation. There is a point beyond which the increased levels of security are no longer justified by these increases.	PSO: In SembCogen's view, what then is the level of security/reliability acceptable to the consumers? EMC: These costs have been considered in the CBA study. Please refer to section 7 of the concept paper.

Comments from Sembcorp Cogen	PSO/EMC's response
4 It is clear that the PRC will result in increased energy, regulation and reserve costs.	PSO: The examples in the paper were arrived at assuming no change in Gencos' offer. One could expect significant changes in Gencos' offer that would alter the dispatch level as well as reserves requirement significantly.
5 The PRC fails to quantify the net benefit that the increased level of the reliability will have and the cost implications for market participants both on the supply side and demand side of the industry.	EMC: Please refer to section 7 of the concept paper.
6 The study discussed in the PRC is too narrow in scope and ignores the implications of changes to the runway cost allocation method. It also offers no insight into the historical and future occurrence of multiple unit contingencies in the NEMS. Sembcorp subsequently clarified that the implication we are referring to is market efficiency. Would need EMC to study why the existing NEMS framework/methodology is inadequate, why PSO's proposed methodology is better and why no other methodologies are considered. How is our reserve market doing compared to other liberalized markets? How will this change affect the consumers, market participants and the industry at large. Would PSO's concern on insufficient reserve be resolved should the proposed rule change gets implemented? If yes, then is it the best solution and can EMC justify the rule change by quantifying the benefits vs. the cost incurred by the proposed new methodology? From our perspective, the proposed rule change is clearly double-penalizing the gencos by placing a cap on less reliable plants who already suffers financially by being scheduled less for energy and reserve by the MCE and yet they are punished again by paying higher reserve cost. EMC would need to address the concern on equitability.	PSO: Issue on cost-allocation will leave it to EMC. Historical records of multiple-units contingencies can be easily extracted from NEMS' advisory notices. EMC: A CBA study is carried out based on historical occurrence of MUC incidents. Please refer to section 7.2 of the concept paper for the historical occurrence of MUC incidents provided by PSO. Please see the CBA results in section 7.2 of the concept paper. There is no double counting so equity is not an issue.

Comments from Sembcorp Cogen	PSO/EMC's response
7 The PRC seems to also allocate costs to parties that are not able to manage the risks and in some cases doesn't allocate reserve costs in an appropriate manner. Consequently, the net benefit of the PRC is unknown at this stage and would need to be assessed and proven before the rule changes could be brought into effect.	EMC: please see our response to point 3 of your comments below Please see the results of CBA study in section 7.2 of the concept paper for the net benefit of the PRC.
3. Decision-Making Processes of the PSO 1 The standard in many electricity industries around the world is to operate according to an N-1 security criterion. When there is the occurrence of a multiple cascading failure, it will be dealt with through system operator intervention and emergency procedures. In some cases, compensation may be paid to generators so as to create the incentive for all participants to return the power system to a normal mode of operation while this is deemed necessary.	PSO: Key word here is "When there is occurrence", PSO will always switch to its emergency procedures whenever such incidents occur.
2 These procedures exist in the NEMS and it is not explained why they are currently insufficient to manage power system security adequately.	PSO: The proposed rule change is to minimize (if not prevent) future occurrences whenever such risks are identified, which the current NEMS doesn't address. This was also made known to the industry in the E&G meeting in Dec 2007 as well as in the industry briefing for this concept paper.
3 That said, the PRC seeks to enhance the PSO's discretion yet fails to completely explain the decision-making process that the PSO will use. In particular: -There appears to be no process requiring the PSO to consult with market participants prior to the declaration of multiple-unit contingencies	EMC: The criteria (described in the PRC) that trigger multi-unit contingencies will be set out in the market rules if the RCP recommends the implementation of PRC. The market rules will also detail a set of procedures in place in the rules for both the PSO and EMC to follow when a multi-unit contingency is activated.

Comments from Sembcorp Cogen	PSO/EMC's response
– for example, there is no mention of steps that the PSO would undertake to verify that in fact the set of circumstances does constitute a credible threat to the operation of the power system. Of concern are multiple-unit failures that were coincidental or that have an extremely low probability of having ever occurred.	PSO: (Low Crime doesn't mean No Crime), i.e. Low probability doesn't mean it would not happen. The scenarios presented had clearly spelled out the threat to the security of the power system under those circumstances. PSO's priority is to secure operation of the power system asap, hence multiple-unit contingency has to be imposed as soon as threat is identified. Affected Genco would be informed prior to the declaration of multiple-unit contingency. Detail procedure is still being discussed between PSO & EMC. EMC: The conditions as describe in the concept paper under which the PSO can activate a multi-unit contingency will be set out in the rules if the RCP recommend the implementation of the PRC. Once the conditions are met, the PSO may activate the multi-unit contingency. There is no need for further consultation. However, we will consider how much advance notice should be given to the market.
-The criteria and information on which the PSO makes decisions regarding the identification of multiple-unit contingencies is not explained in sufficient detail; Sembcorp subsequently clarified that they would like to see the proposed guiding principles and operating procedures of PSO for the identification and activation/deactivation of multi-unit contingencies. A thorough study on single point failure for all the plants are critical for this proposed rule change. Also, a transparent approach would be for PSO to identify upfront the possible cases/scenarios that will be considered co-dependent tripping. However, if after a thorough study conducted by EMC proves that PSO's proposed rule change is unwarranted or inadequate to replace the existing methodology on provision of reserves, there is no need for the guiding principles or operating procedures.	EMC: The activation criteria stated in the concept paper is clear. Would appreciate MP to advise specifically what other details is needed. EMC: If the RCP recommends the implementation of the proposal, PSO would be asked to respond to Sembcorp's suggestions.

Comments from Sembcorp Cogen	PSO/EMC's response
-In some cases, the information on which the PSO will act will be outside the electricity industry (status of gas supply equipment) – no explanation is provided as to where this information will come.	PSO: Information on gas system shall be obtained from our Gas Monitoring System and verified with the GSO or ORF operators where appropriate.
-There is no discussion of the process or steps by which a participant proves that units are no longer to be considered a multiple-unit contingency in the MCE;	PSO: It would be similar to the verification process of a single CCP as multiple GRFs. Details shall be provided at a later stage. EMC: For type 1, the process is described in the Transmission Code (TC). Please refer to C6.9 of TC. For Type 2 and Type 3 events, once the conditions used to activate the contingencies are no longer present for those units, then these units will no longer be considered as part of multi-unit contingency.
-The current methodology for the computation of SPFs used in the runway allocation process is penalising cogen and is reflecting the probability of failure incorrectly. For example, if the steam turbine of a 2-2-1 configuration unit trips, the entire 2-2-1 unit is considered down even though the gas turbines are still running. The PRC fails to address the SPF portion of the reserve framework	PSO: This is out of scope as there is no need to change the SPF computation method. In any case, it has been discussed before and decided upon. EMC: Agree with PSO. the existing methodology for SPF computation set by EMC had been discussed
- The PSO does not have an incentive to take into account market price implications in making decisions as they relate to the operation of a secure power system – noting that this is a consequence of the way in which the market rules define the PSO's role to be concerned solely with power system security	PSO: Electricity Act also requires EMA/PSO to maintain secure operation of the power system.

Comments from Sembcorp Cogen	PSO/EMC's response
4 The PRC also does not clarify what obligations will be imposed on the EMC and what information the EMC will provide to the market participants on the declaration of a multiple-unit contingency by the PSO.	EMC: Upon the PSO's activation of any multi-unit contingency, information (e.g. the type of contingency, affected units and the duration) will be released to the relevant participants. EMC's obligations will be to effect PSO's activation of MUC. If the RCP recommends the implementation of the proposal, we will consider what information should be provided and to whom the information should be provided.
5 Without sufficient clarification of these issues, the PRC would seem to provide the PSO with too much discretion without any clarification of their decision-making responsibilities. This creates uncertainty for market participants and is a potential source of inefficiency in the NEMS. Because the PSO has no obligation to consider the market efficiency implications of operating a power system to an increased level of security, this will result in increased costs that will ultimately be borne by electricity consumers or in some cases that will be unfairly allocated to existing market participants.	PSO: As responded earlier, Details shall be provided at a later stage. EMC: Please refer to the CBA results in section 7 of the concept paper.

Comments from Sembcorp Cogen	PSO/EMC's response
<u>4. Specific Issues on Type 1 Multiple-Unit Contingencies</u> 1. The way in which the MCE would be modified to handle Type 1 multiple-unit contingencies is not consistent with the physical reality of some unit configurations / failure modes. Consider the following example: -It may be that a power station is considered in the MCE to comprise two GRFs: G1 and G2; -Say the MCE dispatches the two GRFs and G1 may fail; -as a consequence of the configuration / operating mode of the Gas Turbines and Steam Turbine, G1 operates at 0MW and G2 is left generating alone for dispatch. In this case, the PRC implies that the G1 and G2 would both be declared co-dependent which is inconsistent with the physical reality and therefore a source of market inefficiency because:	PSO: This is not new, the same requirements were present in the pre-NEMS Transmission Code which was proposed by SembCogen. The same has also been reflected in the updated Jan 2008 Transmission Code.
-More reserves will be procured to cover these co-dependent units than what is necessary resulting in higher costs in energy, regulation and reserves -this distorts market signals through inappropriately pricing of energy and ancillary services; -It also results in inefficient use of resources and places an unnecessary burden on power stations that have co-dependent units that aren't being represented in the MCE correctly; and	PSO: This may not necessarily be the case. Detail procedure is still being discussed between PSO & EMC.

Comments from Sembcorp Cogen	PSO/EMC's response
-Acts as a barrier to the entry of new power stations that have configurations similar to the ones described above because they will be unfairly and inappropriately represented in the MCE.	PSO: As mentioned earlier, this form of representation was proposed by SembCogen and was already present in the pre-NEMS Transmission Code, which was subsequently adopted by the NEMS.
2. Prior to the first occurrence of a multiple-unit contingency of this kind, the power system is effectively operating in a state that is insecure. There is no obligation on the PSO to investigate ahead of time to identify the possibility of multiple-unit contingencies and/or to consult with the GENCOs that have such units in terms of assessing the probability of such failures occurring.	PSO: This is a serious allegation. All CCP that have been registered as multi-unit GRFs were subjected to a set of comprehensive tests in compliance to the Transmission codes. It is the responsibility of the Gencos to ensure that the plant operates as it is designed. Is SembCogen implying the tests that its CCP were subjected to were invalid or that regular re-tests be conducted?
3. As stated, the PRC fails to discuss whether the GENCO is consulted by the PSO following the occurrence in order to ensure that the multiple-unit contingency does in fact represent a credible threat to the operation of the power system.	PSO: PSO's priority is to secure operation of the power system asap, hence multiple-unit contingency has to be imposed as soon as threat is identified. Affected Genco would be informed prior to the declaration of multiple-unit contingency. Detail procedure is being workout between PSO & EMC. EMC: The conditions under which the PSO can activate a multi-unit contingency have been set out in the concept paper. They will also be set out in the market rules should the RCP recommends the implementation of this proposal. Once the conditions are met, the PSO may activate the multi-unit contingency. There is no need for further consultation. However, we will consider how much advance notice should be given to the market.

Comments from Sembcorp Cogen	PSO/EMC's response
4. The process for proving that units are no longer co-dependent is not discussed;	PSO: It would be similar to the verification process of a single CCP as multiple GRFs. Details shall be provided at a later stage.
5. The PRC states it will assume that any unit in a group of co-dependent GRFs is considered equally likely to trigger the failure of another unit. This is subsequently used to justify the allocation of costs to multiple-contingency groups in the runway cost allocation for type 1 contingencies. This assumption is not necessarily correct for many unit configurations in the NEMS and therefore does not allocate costs in a way that is fair Consider the following example: -It may be that a power station is considered in the MCE to comprise two GRFs: G1 and G2 with capacities of 300MW each; -Say the failure of G1 results in the failure of G2 but the failure of G2 does not result in the failure of G1; -In the cost allocation method, G2 will be treated unfairly because it is assumed that it can cause the failure of G1 as well and therefore receives a block in the runway method that is equal to the sum of generation from G1 and G2; -Consequently the GENCO owning G1 and G2 receives a greater share of the costs than should be the case and is a source of market inefficiency that would affect not only the short-term operation of the GENCO but also potential future investment in plant configured this way. This situation might be improved if the PSO is required to investigate the reasons for multiple-unit contingency and the MCE model formulation is amended to represent such types of multiple-unit failures in a way that is realistic.	PSO: Can EMC respond? EMC: If the RCP recommends the implementation of MUC, PSO would be asked to advise whether such codependency relationship of these two units as described by Sembcorp is valid and whether it can be taken into account in the calculation of risk size for each unit. i.e, in the example situation, the risk size of G1 will be calculated as (G1+% of G2), the risk size of G2 remain as G2. PSO: Defaulting Genco would have to provide detailed investigation report to PSO in any case. PSO: Is SembCogen refering to Settlements issue instead of MCE modelling?

Comments from Sembcorp Cogen	PSO/EMC's response
	EMC: This is not just settlement issue.
6 The MCE already allows for the possibility of secondary contingency units (SCUs). It is not explained why this option has not been used to model these issues.	PSO: The proposed rule change is not simply to increase Reserve requirement, but to have adequate reserve scheduled by the MCE dynamically to cover the identified risk of multi-unit tripping. This was also made known to the industry in the E&G meeting in Dec 2007 as well as in the industry briefing for this concept paper. Perhaps SembCogen would like to refer to the distributed slides. EMC: SCU is a GRF that is expected to disconnect automatically from the transmission system if the frequency of the transmission system falls due to failure of the largest GRF. It is different from the type 1 multi-unit contingency case, where the two GRFs are codependent and the tripping of one is caused by the other and vice-versa. Their tripping is not due to the fall of frequency in the transmission system due to the largest GRF.
7 The process for identification of co-dependent units is inappropriate and may result in incorrectly classifying co-dependent units; for example the following aren't checked for: - coincidental outages – these should not be classified as being multiple-unit contingencies;	PSO: Why not? Onus is on the defaulting Genco to show that the simultaneous trippings of GRFs under its charge were not related.

Comments from Sembcorp Cogen	PSO/EMC's response
- causality in the outages is not considered yet important – as described above these are not fairly allocated costs in the changes proposed to the runway allocation method; and	PSO: PSO's priority is to secure operation of the power system asap, hence multiple-unit contingency has to be imposed as soon as threat is identified. Can EMC respond on the cost allocation issue?
- identifying and representation of partial outages – as discussed these aren't modelled appropriately in the MCE.	PSO: Is SembCogen refering to Settlements issue instead of MCE modelling? EMC: This can be discussed with PSO on whether codependency factors should be used to address this.
8. It would seem that the following options have not been considered by the PSO as alternatives to addressing this problem: - Improving grid connection standards to avoid the presence of co-dependent units in Singapore – this may however, create a barrier to investment in new plant and/or investment in the wrong type of plant;	PSO: There is already a generating plant design requirement in the Transmission Code. However, incidents of multi-unit tripping showed that either the GRFs were not operated or that changes had been made on the plant design after the initial commissioning in a manner consistent with the requirement.

Comments from Sembcorp Cogen	PSO/EMC's response
- The rules governing what constitutes a GRF may be inappropriate as the unit sizes dispatched don't always correspond to the MW that would be lost given a unit failure; and/or -Enhancing the MCE formulation to properly represent the partial failures of the type described and imposing obligations on the PSO to properly investigate multiple-unit contingencies.	PSO: PSO's priority is to secure operation of the power system asap, hence multiple-unit contingency has to be imposed as soon as threat is identified. Defaulting Genco would have to provide detailed investigation report to PSO & MSCP in any case.
9. In summary the Type 1 contingencies as stated in the PRC will not result in efficient market outcomes as a consequence of the shortcomings identified above. As a minimum the PRC needs to address these issues outlined above.	PSO: Disagree. The propose rule change is the most efficient way of determining the required Reserve based on the Largest risk identified.
5. Specific Issues on Type 2 Multiple-Unit Contingencies 1 The PRC does not explain in sufficient detail the distinction between SPPG's grid equipment and the GENCO's equipment;	PSO: Disagree. We would be very surprise if a Genco doesn't know which equipment belong to the Genco.

Comments from Sembcorp Cogen	PSO/EMC's response
2 The calculation of the SPFs is not specified in sufficient detail;	EMC: In our concept paper, it is explained how SPFs will be calculated. For the contingencies attributed to the TL, the SPF should be computed as the number of dispatch periods that the transmission facility experiences forced outage caused by failure of the TL's equipment divided by the number of dispatch periods that the transmission facility is in operation based on the real-time dispatch schedule. For the contingencies attributed to the Genco, to compute the SPF, the number of dispatch periods that the transmission facility experiences forced outage caused by failure of Genco's equipment would be used for the numerator. Please refer to section 5.2 of the updated concept paper.
3 It is not stated whether there will be any obligation on the SPPG to consult with the GENCO in terms of the scheduling of maintenance that may lead to the Type 2 contingency situation;	PSO: Disagree. Our experience show that any maintenance work that involve Generation Connection circuits, Gencos would always be consulted.
4 It is not stated what obligation is imposed on the SPPG to return failed lines to service that give rise to a Type 2 contingency situation;	PSO: The proposed cost allocation by the EMC would already address this. EMC: the proposal does not "impose" any such obligation. The cost allocation proposed will provide incentive for SPPG to do so in order to minimize the cost.

Comments from Sembcorp Cogen	PSO/EMC's response
5 As specified in the grid code, the network should be operated according to an N-1 criteria and issues associated with its operation are the responsibility of the grid operator;	PSO: Transmission Code only requires network to be planned/design on N-1 criteria precisely because maintenance are required from time-to-time. Genco is aware and it is for Genco to decide if additional connection circuit is required.
6 In summary type 2 contingencies as stated in the PRC requires substantial clarification on the process that will be used.	PSO: Detail process is still being workout between PSO & EMC.
<u>6. Specific Issues on Type 3 Multiple-Unit Contingencies</u> **1** Costs are not allocated to participants that are able to manage the risk; **2** Issues associated with time-lags in the supply of gas and associated disruptions are not addressed; **3** It appears that coordination between upstream asset owners and the PSO is required at least in the timely communication of information regarding the status of gas supply equipment – this is not addressed or explained in the proposal.	EMC: We have explained in the concept paper that the corresponding Genco is the party that would be best able to manage such risks by taking certain mitigation measures. PSO: What is this issue about? PSO: This is already been done, but what does this has to do with the proposed rule changes.

Comments from Sembcorp Cogen	PSO/EMC's response
4 In summary type 3 contingencies as stated in the PRC requires substantial clarification on the process that will be used.	PSO: Detail process is being workout between PSO & EMC. EMC: Other than the lead time that PSO needs to give to the market and who should receive what information, other details (e.g. What constitutes the 3 types of Multi-unit contingency; the activation criteria; what information needs to be provided for activation; who bears the reserve cost and how the SPF would be computed) are already explained in the concept paper. If the market participant thinks that there are missing pieces, please let us know specifically what they are.

Comments from Keppel Merlimau Cogen	PSO/EMC's response
General - Clear procedures and proposed implementation schedule need to be laid out for further discussion as to how multi unit contingency risks are to be identified and attributed to market players. Keppel Merlimau Cogen subsequently clarified that the paper would require details as to the definition of MUCs, be they type 1, type 2 or type3. For example Type 1.Would this include all systems which are multi-units within a single generation licensee's premise? i.e. seawater intake facilities, water treatment facilities, etc. Definitions and boundaries would need to be drawn specifically so that there is no ambiguity. If such systems are identified to be multi-unit, how would authorized parties be informed of such and how would the procedures for activation be controlled and regulated in a meaningful manner?	EMC: Other than the lead time that PSO needs to give to the market and who should receive what information, other details (e.g. What constitutes the 3 types of Multi-unit contingency; the activation criteria; what information needs to be provided for activation; who bears the reserve cost and how the SPF would be computed) are already explained in the concept paper. If the market participant thinks that there are missing pieces, please let us know specifically what they are. EMC: If the RCP recommends the implementation of MUC, PSO will be asked to respond to these questions. PSO: Detail process is being workout between PSO & EMC.

Comments from Keppel Merlimau Cogen	PSO/EMC's response
- Clear trigger factors and/or activation criteria would need to be adequately addressed and justified for market participants affected by all risk types. This also applies for the deactivation process and any error in risk activation.	EMC: For deactivation of type 1, the process is already explained in section C6.9 of TC. For deactivation of type 2, once the conditions are no longer present, the PSO's should notify from which trading period onwards Type 2 should be deactivated. PSO: Activation/De-activation of multi-unit contingencies could be thru the existing Advisory Notices published at EMC website for all market participants. Details are being workout between PSO & EMC.
- Are multi unit contingency risks prevalent in other similarly reformed electricity markets globally? Has studies been performed to examine the viability and practicality of mechanisms and allocations proposed in the current context.	EMC: We are aware that type 2 risk is present and modeled in New Zealand's Electricity Market. The PRC is implementable.
- Communication of all possible risk(s) – whose responsibility and if the responsible party is in default of not providing clear and sufficient communication to affected market participants, how would such breach be handled?	EMC: The party in default would have potentially breached the market rules if any communication is not made in accordance with the market rules.
Type 1: Two or more GRFs are codependent - The use of 2-2-1 CCP to illustrate such risk type is misleading. The market is fully aware that 2-2-1 units are subjected to extensive tests to conform and satisfy PSO's requirements in order to be registered as two independent units.	PSO: 2-2-1 CCP is used as an example only. It is true that these had passed the verification tests during commissioning. However, incidents of multi-unit tripping showed that there were cases where either the GRFs were not operated or that changes had been made on the plant design after the initial commissioning in a manner consistent with the requirement.

Comments from Keppel Merlimau Cogen	PSO/EMC's response
- Definition of codependency will need to be examined closely as common systems are prevalent in all generation facilities. - The proposed reserve cost allocation for Type 1 risk shows codependent units being penalized twice for a significantly larger amount of reserve allocation. We view this as unfair and that the proposal should be reconsidered.	PSO: Bottom-line is that no more than one GRF should trip due to failure of any equipment within the Genco's control. The fact that it could result in multi-unit tripping already showed that there is co-dependency. EMC: If the units are co-dependent, then the reserve cost allocation proposed does not double count the risk they pose to the system. Please see example in Appendix 3.1.
Type 2: Multiple GRFs connected through one single Transmission Facility - Design of current grid network is based on N-1 contingency level. To allocate costs to the transmission licensee (TL) would have direct impact to existing and future network planning costs. Cost allocation to market participants would also have direct impact to costs for both current and new players. The implications of the above will need to be considered thoroughly.	PSO: It is our understanding that unlike the rest of grid network, cost of Generation Connection circuits is borne mainly by the relevant Genco. EMC: In our proposal, the cost bearer is best incentivized to mitigate the risk. This is consistent with the "causer pays" principle.
- **Type 3: Gas disruption risk** It is unfair for market participants to solely bear the additional reserve cost allocation just because the existing electricity market rules do not apply to the gas market players. Significant efforts should be taken to integrate and reinforce the gas network to address such related risks.	EMC: For the regime to be implementable, the associated costs required to cover the risk have to be allocated efficiently. The wholesale market design prescribes a de facto causer pays principle. In the event that cost cannot be passed to the causer, the second best solution is to pass the cost to the party best able to manage the risk. This is preferred to the last option which is to socialize the cost across the market. It is preferred because it creates an incentive for the parties able to manage the risk to take action to avoid or minimize the costs. If we socialize the costs, there would be no incentive for anyone to take action to reduce the risks, which reduces economic efficiency.

Comments from Keppel Merlimau Cogen	PSO/EMC's response
	We have explained in the concept paper that: In multi-unit contingencies that are due to the outage of ORF and metering facility, while the relevant genco is not the causer, that genco is the party that is best able to manage those risks by taking certain mitigation measures. For instance, the Gencos can coordinate with the gas suppliers and gas transporters so that the gas pipelines, the metering facilities and the diesel systems would not be on maintenance at the same time. Those currently served by only one gas pipeline can also consider getting service from an additional gas pipeline. They can also reduce the risk by adjusting the output level of their generation facilities. In multi-unit contingencies that are due to the outage of the receiving facility, the genco is the causer because it controls the receiving facility.

Comments from SP PowerAssets	PSO/EMC's response
We refer to your concept paper EMC/RCP/2008/CPI7. 2 We strongly disagree with EMC'S proposal for the Transmission Licensee to bear the reserve costs arising from Type 2 - Transmission Risk as defined in the concept Paper.	EMC: We propose to allocate the reserve cost to the TL according to the "causer pays" principle. When the market was first designed, the transmission system was considered robust and hence transmission risks were not modeled in Singapore at that time. (Please refer to 2.13 of PHB's memorandum "Wholesale Market Design"). Thus, transmission line contingencies were not included in the calculation of reserve requirement. However, the PSO has now identified certain scenarios where transmission lines pose risks to system security. Hence, it is natural that the transmission licensee should bear the reserve cost associated with the risks posed by such lines.
3 As the Transmission Licensee, we plan and develop the transmission network in accordance with the Transmission Code. We are not required to cater for the proposed multi-unit contingency situations as this will have cost impact on customers.	PSO: It is our understanding that unlike the rest of grid network, cost of Generation Connection circuits is borne solely by the relevant Genco.
Furthermore, EMA has already imposed a set of SOPS since Aug 04 to govern our network performance. It is therefore inappropriate for EMC by means of the proposed reserve costs allocation scheme to impose another performance measure on us.	EMC: See response to point 2 above.

Comments from SP PowerAssets	PSO/EMC's response
4 SPPA operates under a regulated regime which is entirely different from the competitive wholesale electricity market. Under the regulated business model, our revenue is largely based on recovery of caper and opex plus an allowed return on our regulated asset base. It should be noted that such a regulated revenue control does not take into account any wholesale market related cost.	EMC: According to MR, the TL is also a MP who must comply with MR. This means that if this rule change goes through as currently proposed, the TL will need to take such multi-unit contingencies into its operational considerations.
5 In conclusion, the structure of the current electricity market clearly segregates the competitive market segment from the regulated transmission and distribution businesses. There should be proper cost ring-fencing within each market segment and each entity should be subject to its own performance scheme imposed by the Authority. Hence, we should not be made to bear any reserve cost as proposed by EMC.	EMC: Understand that SPPA is also a regulated entity. See response to point 2.

Comments from Power Seraya	PSO/EMC's response
1 Post event mechanisms 1.1 In the event that any of the multi-contingency risk occurs what are the administrative and logistical set-up and procedures in terms of information release lead-time and mode of communication to affected generators?	PSO: PSO's priority is to secure operation of the power system asap, hence multiple-unit contingency has to be imposed as soon as threat is identified. Affected Genco would be informed prior to the declaration of multiple-unit contingency. Activation/De-activation of multi-unit contingencies could be thru the existing Advisory Notices published at EMC website for all market participants. Details are being workout between PSO & EMC. EMC: We will take this into consideration when designing the procedures.
1.2 once a unit has been identified to fall under any of the risk categories how long will said unit remain in this state and what are the factors that would allow said unit to be revert to its original status?	PSO: If it is Type 1, after satisfactory demonstration thru tests and submission of detail investigation report. If it is Type 2/3, after the risk has been removed. Details are being workout.
1.3 In the event that PSO failed to declare or identify timely the multi-unit contingency risk during a multi-unit tripping, will a re-run be conducted?	EMC: No rerun will be conducted.
2 **<u>Impact on Costs</u>.** The proposal will drive up the cost of energy and reserves as evidenced by the simulations done by EMC. This cost will ultimately be borne by consumers contrary to the aim of liberisation of the electricity market of lowering cost thru competition.	PSO: The examples in the paper were arrived at assuming no change in Gencos' offer. One could expect significant changes in Gencos' offer that would alter the dispatch level as well as reserves requirement significantly.

Comments from Power Seraya	PSO/EMC's response
	EMC: Liberalization aims to improve economic efficiency through introducing competition. Competition would create downward pressure on prices compared to a situation where there is no competition. Nevertheless, it does not necessarily lead to lower cost of electricity to consumers.
3 <u>Cost Recovery.</u> The proposed rule change will entail additional costs for generators. We have modeled the impact of the proposal and this resulted in the doubling of the overall reserve requirement. This will require Gencos to decrease the energy they offer in the market and likely lead to a substantial tightening of the energy supply, thereby increase market prices of energy from steam plant at best and OCGT at worst. Since the purpose of the proposed rule change is to provide a more reliable and stable electricity supply to consumers, it is only fair that the resulting increase in cost be shared by the end- beneficiaries as well.	PSO: The proposed rule change is not simply to increase Reserve requirement, but to have adequate reserve scheduled by the MCE dynamically to cover the identified risk of multi-unit tripping. Given the available reserves it is unlikely that there would be doubling of reserve requirement. EMC: Unaffected generators do not have to decrease energy offers. And charging reserve costs directly to end users would not help improve system security because end users have no control over generation and transmission. Charging reserve costs to gencos and transmission providers incentivize them to reduce the risks and the associated cost they pose to the system. End-users will ultimately pay for reliability through energy and regulation charges (which are set by generators).
<u>4 Modeling.</u> We find that EMC'S assumptions that the proposed rule change (a) will not affect bid behavior and (b) considering only groupings of 2 generators for type 2 and 3 risks may not be accurate and representative of the actual market scenario. May we suggest that a more comprehensive modeling exercise be undertaken and Gencos be invited to take part in the said exercise to yield more realistic results.	EMC: However, the proposed exercise also has its own limitation. We cannot ensure that an unbiased exercise can be conducted with market participants or that market participants will response realistically since they do not face the cost or derive benefit from the situation.

Comments from Power Seraya	PSO/EMC's response
<u>5 Type 2 Risk.</u> 5.1 Setting the reserve recharge where the lower limit on the Standing Probability Failure (SPF) at 0.001 appears too high as Gencos will bear a large share of the cost even at this level. Instead a more accurate number is much closer to 0. The aggregate output of generators on shared facilities could be greater compared to when the SPF limitations were accepted and when the output was limited by a single generator physical capability. We request PSO to revisit this proposal as this may not be reflective of the correct level of recharge.	EMC: Not 0.001, but 0.00001 (which is 0.001%), which is already the smallest number allowed in the EMC's system.
5.2 As service providers SPPG/SPPA are charged for reserve costs but cannot adjust their trading position to insure that they earn enough in the reserve market to repay the costs they are charged.	EMC: Reserve charged is based on the causer-pays principle. It is up to SPPG to manage the cost.
This puts in question the principle of recharging them for reserves. If they are not to be charged then it is difficult to see who can bear the cost in which case we recommend that these costs be amortized through MEUC.	
<u>6 Type 3 Risk</u> It does not make sense that parties for gas supply, being one of the critical factors affecting the reliability of supply of electricity, are not market participants in the SWEM yet the burden of risk mitigation for gas disruption is placed on the Gencos. We find EMC this unfair and baseless. Generators have no control over the operator of the pipeline and associated ORF so Gencos should not be expected to carry the burden of the costs associated with the ORF'S facilities' reliability or otherwise.	EMC: As explained in the concept paper, it is still possible for Gencos to take certain measures to manage the risk/cost.

Comments from Power Seraya	PSO/EMC's response
Similarly, we recommend that these costs be amortized and recharged back to consumers as an additional component of MEUC.	EMC: From the market design standpoint, reserve cost should be allocated to the genco or direct causer if they can be identified. E.g. the transmission company in type 2 cases and where the causer is a market participant. If not, the second-best solution is to allocate the cost to specific gencos or to all gencos. Gencos can factor their reserve cost liability into their energy offers thereby charging them back to consumers

Comments from Senoko Power	PSO/EMC's response
The background to this concept paper, as we understand it, was that the Power System Operator (PSO) had concerns that a single event could trigger multi-unit trips, due to the units' configuration. The concept paper listed three types of multi-unit events that could occur: — shared elemental/functional system by more than one generating units (Type 1: co-dependent GRFs); — the transmission facility (Type 2: single transmission facility); or — disruption of gas supply (Type 3: gas disruption risk). We understand that the proposal is still at the conceptual stage and no analysis as to the extent of consequential market rule and system changes (i.e. cost) has been undertaken. However, we understand that if this proposal were to go ahead, the Market Clearing Engine (MCE) would have to be modified at a cost to all Market Participants.	
Materiality of risk not evident The key issue of materiality has not been addressed. We would be grateful if the PSO could provide statistics that show the occurrence of such multi-unit events is frequent enough to warrant the changes. Indeed, Singapore's record of customer interrupted minutes is the best in the world and does not warrant this level of prudence with regard to reserves. Senoko's observation of the market is that such multi-unit events have occurred very rarely. Given the potential cost outlay and likelihood of disputes that will arise, Senoko requests the PSO to provide market participants with clarity as to the materiality and probability of such risks before we consider any proposed rule modification and implementation.	PSO: We are surprised that Senoko has forgotten the 21-Dec-2006 incident where 2 of its CCPs tripped resulted in wide-spread blackout. The proposed rule change is to minimize (if not prevent) future occurrence whenever such risks are identified. (Low Crime doesn't mean No Crime), i.e. Low probability doesn't mean it would not happen. The scenarios presented had clearly spelled out the threat to the security of the power system under those circumstances. PSO's priority is

Comments from Senoko Power	PSO/EMC's response
	to secure operation of the power system asap, hence multiple-unit contingency has to be imposed as soon as threat is identified. Historical records of multiple-units contingencies can be easily extracted from NEMS' advisory notices by Senoko. EMC: The materiality and probability of the risk is considered in the cost-benefit analysis study. Please refer to section 7 of the concept paper.
Inconsistent "use of causer pays" principle While the paper states that the Singapore Wholesale Electricity Market operates on a "causer pays" principle, the proposed solutions do not seem to adhere to this principle. *Gencos bear burden of gas suppliers and transporters* For example, in the case of an outage occurring at an ORF or upstream portion of the gas pipeline (Type 3), the gencos rather than the gas suppliers or gas transporters are to bear the additional reserve costs. The reason given was that the gas suppliers and transporters are not participants of the Pool and thus cannot be imposed with reserve costs. Gencos are deemed "the next best party that is able to manage this risk". This is inequitable and discriminatory. It appears that the reserve burden is thus placed on the gencos as a matter of convenience. We find this position preposterous and object to any unjustified attempts to impose this unnecessary burden on us. The PSO must understand that the gencos are in no position to negotiate with our gas suppliers to impose such terms on them. Any attempt by a party to unilaterally amend the terms of gas supply would be a breach of contract. Contrary to the views of EMC, the gencos cannot manage this risk. We therefore	EMC: EMC proposed that the reserve cost should be borne by Genco in the belief that Gencos are able to manage gas risks. For example, the Gencos can coordinate with the gas suppliers and gas transporters such that the gas pipelines, the metering

Comments from Senoko Power	PSO/EMC's response
view Type 3 as fundamentally inequitable and flawed. Senoko subsequently clarified that barring the activation criterion, this scenario suggests that gencos are to bear the reserve risks of an upstream gas outage on behalf of gas suppliers. For this reason, the gencos are also expected to "manage the risk" via various means, such as (as suggested by you) rescheduling maintenance calendars involving several parties (genco; gas importer; gas supplier); building an additional gas pipeline; and, adjusting the generation level (presumably to reduce reserve cost). What this goes to show is that this MUC risk rule, if effected, will actually impose additional constraints on a genco's operation. For example, (taking the suggestion to adjust generation level), are the gencos expected to reduce or even halt generation from a certain GRF to reduce reserve costs because of the MUC risk of a gas outage upstream? This is untenable especially when the risks arise outside the genco's scope of control.	facilities and the diesel systems would not be on maintenance at the same time. Those currently served by only one gas pipeline can also consider being served by an additional gas pipeline. They can also reduce the risk by adjusting the output level of their generation facilities.
Also, some of the suggested mitigation measures are simply not feasible.For example, under the existing PNG contracts, the gas importer / supplier has the absolute right to decide its maintenance schedule, subject to a notice period (for example, 30 days). The supposed flexibility available to the gencos in reality, therefore, is fairly limited. Building an additional pipeline is a huge venture and is not feasible as a mitigation measure.	EMC: From the design perspective, we maintained our cost allocation recommendation for the reasons explained in our response to comments from various MPs.

Comments from Senoko Power	PSO/EMC's response
Who determines if multi-unit contingency risk exists One question that was raised during an earlier briefing was the identification of the risk as well as the parties to bear the additional reserve costs. The reply from an EMC representative was that such determination would be a "factual" one identifying the equipment setting the risk. We do not believe that the issue is as clear-cut as suggested. We have several questions: a) Can the PSO guarantee its exhaustiveness in identifying multi-unit contingency events?	PSO: Yes, to the best of our knowledge. Senoko is welcome to suggest additional scenarios. EMC: PSO must provide a list of the multi-unit groups in advance for EMC to calculate the SPF.
b) If not, does the PSO expect to gradually augment the list of multi-unit contingency events as they occur?	PSO: Should there be new risk scenarios surface later, these would be included.
c) Does the PSO expect that clear identification of the equipment would definitely result in clear identification of the party bearing the reserve cost?	EMC: This is not a cost allocation issue. It is for the PSO to identify the party responsible for the equipment failure before EMC can do the cost allocation appropriately. The party that has control over the equipment should be the bearer of the reserve cost.

Comments from Senoko Power	PSO/EMC's response
d) If multiple equipment are identified in the contingency risk, how would the PSO expect the reserve costs to be allocated between market participants: on a 50-50 basis, or a proportional basis? On what basis is the sharing of reserve costs determined Without clear answers to these questions on the onset, Senoko cannot be confident that this scheme will be transparent and equitable. The uncertainty of reserve cost allocation represents a major regulatory risk to all market participants.	EMC: If multiple equipment are identified in the contingency risk, then one block each will be created for equipments under the control of each party. Each block has its own SPF. The sharing of reserve cost between the parties would be based on the SPFs of their respective block. The party responsible for equipment that fail more often will bear higher reserve cost because their SPFs would be higher. In the case of Type 2, we expect to have 3 possibilities a) Only Genco is responsible for all the equipment or b) Only TL is responsible for all the equipment or c) both Genco is responsible for some equipment and TL is responsible for some equipment.
Potential cost increases not considered The proposed scheme suggests that market participants might be better off diverting their resources to certain aspects of their operations, in order to minimise their exposure to the increased reserve costs. For example, that the transmission licensee may be penalised in the case of a Type 2 event may cause it to plan its grid projects on an N-2 basis (instead of N-1, as is the normal practice). The additional costs incurred would most likely be recovered from consumers as part of the transmission licensee's grid charges. However, given the low probability of such incidents, this change is not justified.	PSO: It is our understanding that unlike the rest of grid network, cost of Generation Connection circuits is borne mainly by the relevant Genco. Whether to cater for N-2 for Generation Connection circuits, Gencos, SPPA/SPPG would have to decide. EMC: The proposal itself does not impose any new network planning criterion on the transmission licensee. The objective is to incentivize the causer to take measure to manage such risk.
It would thus be a fallacy if the assumption is that the reserve costs would be a one-time cost. We expect this scheme to result in a permanent increase in energy costs. The PSO must consider whether the benefit of this new reserve scheme justifies potential cost increases.	EMC: The increased reserve cost is considered in the CBA study.

Comments from Senoko Power	PSO/EMC's response
No benefit to the reliability of supply We would like to question the PSO again as to what benefit this new reserve scheme would provide to the electricity market. This scheme provides no material improvement to the reliability of supply, yet unduly (and in some cases unfairly) increases costs for market participants.	PSO: This proposal is so that consumers will be provided with a more reliable supply of electricity, PSO's priority is to secure operation of the power system asap, hence multiple-unit contingency has to be imposed as soon as threat is identified. This is immediate improvement. The proposed rule change is not simply to increase Reserve requirement or cost, but to have adequate reserve scheduled by the MCE dynamically to cover the identified risk of multi-unit tripping.
This scheme also serves no purpose in motivating gencos to improve their GRF reliability. In our normal course of business, Senoko is already constantly putting in measures to improve the reliability of our generating units.	PSO: Believe us, Gencos would be strongly motivated. Do your calculations and Senoko will know why. In any case, if Senoko is so confident of its GRFs reliability, it need not worry about impact of this rule changes on its revenue.
At this point, we have not even begun to consider the time and costs associated with modifying the market rules and systems to accommodate this new scheme. This is even more pertinent if we consider whether the risk of multi-unit contingency events occurring is really material and to what extent it is.	PSO: Our understanding is that cost of modifying the MCE would not be prohibitive. EMC: we will provide the RCP estimated cost of system changes as part of rule change process for RCP to consider the proposal.

Comments from Senoko Power	PSO/EMC's response
Major uncertainties still exist At this stage, major doubts about this new reserve scheme remain. Many issues have been raised during the earlier briefing session, and we expect that other market participants will be submitting their comments.	PSO: What are these issues? The proposed rule change is to minimize (if not prevent) future occurrence whenever such risks are identified, which the current NEMS doesn't address. This was also made known to the industry in the E&G meeting in Dec 2007 as well as in the industry briefing for this concept paper. There was no significant issues raise then.
We request the EMC to conduct at least one more public forum for market participants before releasing another concept paper. Our opinion is that this concept paper cannot proceed as a rule change proposal due to major flaws and uncertainties and until the issues we have articulated have been addressed. We look forward to working with the PSO and EMC on this matter.	EMC: We will respond to each market participant's comments and if necessary, we will have another public forum.

Appendix 3.1: Illustration of Reserve Cost Allocation for Codependent GRFs

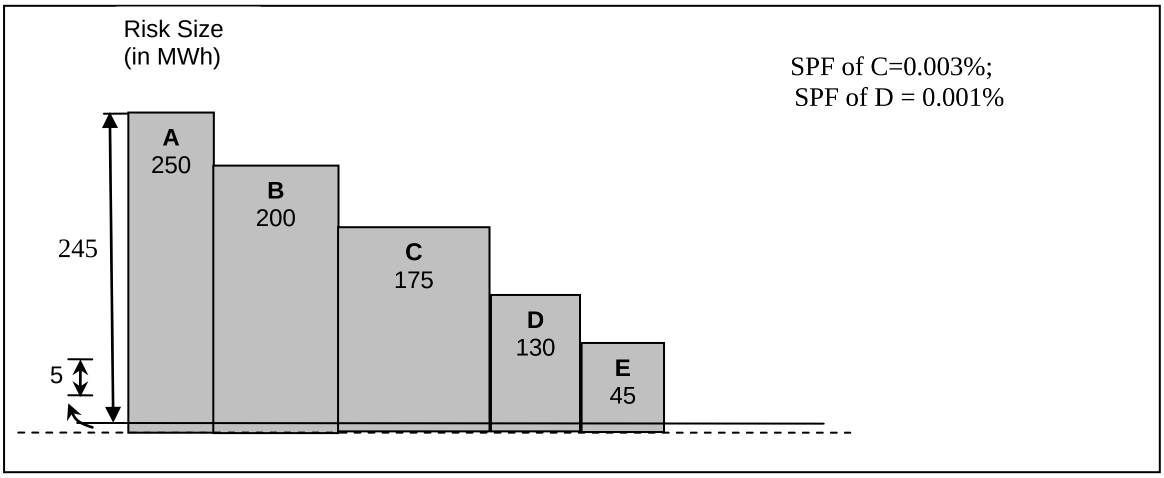


Figure A3.1 Existing Modified Runway Method for Reserve Cost Allocation

In the concept paper, it is proposed that for the reserve cost allocation of Type 1 MUC, the risk size of both blocks used to represent the co-dependent GRFs be increased. There is no double counting of the risks these co-dependent GRFs pose to the system.

Please note that by "co-dependency", we mean that the operation of two (or more) GRFs depend on each other .The tripping of either GRF would (always) lead to the tripping of the other GRF. Thus, the risk size of both GRFs would be the sum of the scheduled energy of the two GRFs (see Figure A3.2 below). Thus, in reserve cost allocation method, we proposed to increase size of both GRFs to reflect such facts. The probability of failure of each GRF should remain the same as we assume that the existing probability of failure of each GRF represent the probability of each GRF's independent tripping already.

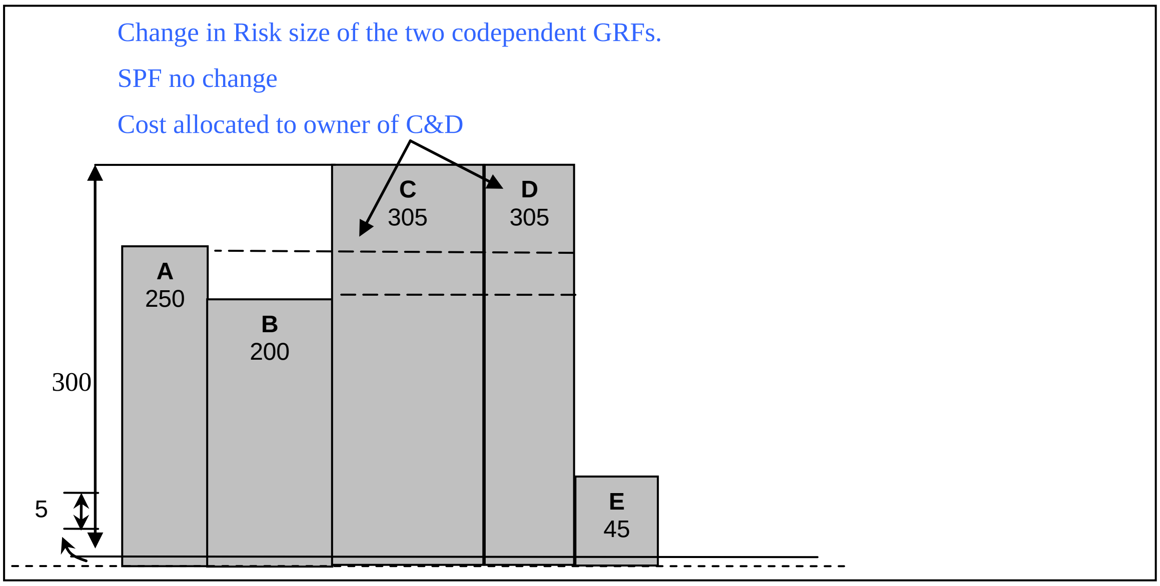


Figure A3.2 Proposed reserve cost allocation method

Alternatively, we can also choose to create another new block to represent such contingency of simultaneous tripping of two co-dependent GRFs (see Figure A3.3 below). As such simultaneous tripping could be caused by the tripping of either GRF, thus the probability of failure of the new block would be the sum of the probability of failure of the two co-dependent GRFs. The risk size of this new block would be the total scheduled energy of the two co-dependent GRFs. The existing blocks for GRF C and GRF D would be removed since there is no longer such incident of tripping of GRF C or GRF D only.

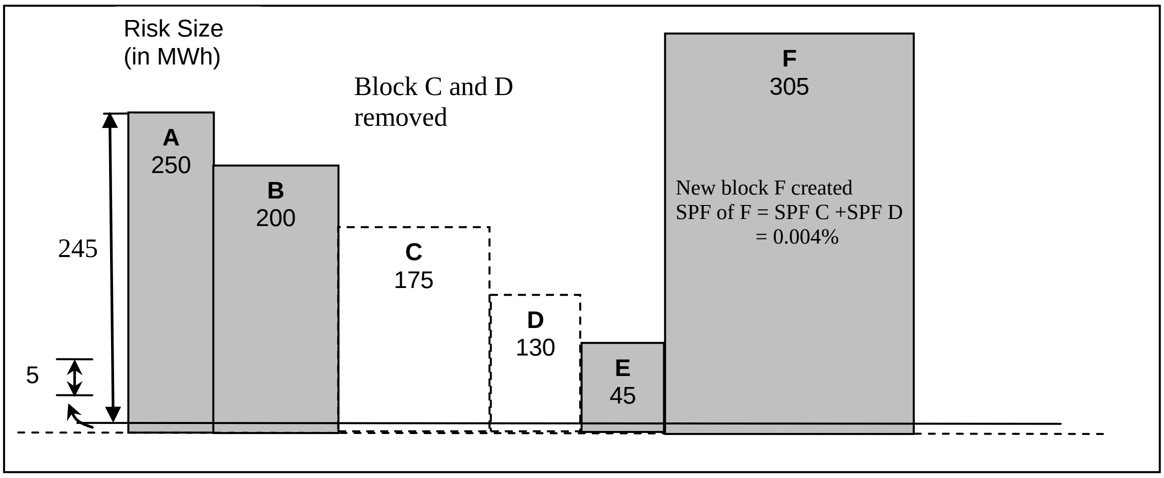


Figure A3.3 Alternative reserve cost allocation method

Comparing Figure A3.2 with Figure A3.3, it can be seen that the reserve cost allocated to block C and D in Figure A3.2 would be the same as the cost allocated to block F in figure A3.3. The co-dependent GRFs are not penalised twice in the proposed method as illustrated in Figure A3.2.

Annex 4: Proposed CBA Methodology

PROPOSED COST-BENEFIT ANALYSIS FRAMEWORK FOR THE PROPOSAL "CP17: MODELING OF MULTI-UNIT CONTINGENCY RISK"

PURPOSE

For industry consultation, EMC has prepared a draft Cost-Benefit Analysis (CBA) framework for the Conceptual Proposal "CP 17: Modeling of Multi-unit Contingency Risk". During the first consultation phase for this proposal, market participants requested that a CBA on this proposal be performed.

EMC'S APPROACH

EMC began by searching for similar CBAs that might have been conducted in other markets but was unable to find any. We then conducted a literature review to seek out usable methodologies or concepts that can be adapted. This was also only partially successful because there did not appear to be any proven methods suited entirely for our purpose.

ESTABLISHING THE BENEFITS

In our literature review, we came across a methodology developed to efficiently determine spinning reserve requirement. The paper[1] describing this methodology used a Cumulative Outage Probability Table (COPT)[2] to derive Estimated Energy Not Served (EENS) for a given reserve regime. We have chosen to adopt that methodology to quantify the potential reliability benefits of modeling multi-unit contingency risks.

ESTABLISHING THE COSTS

Our literature review did not produce useful guidance on how to estimate the full costs (other than obvious implementation costs) associated with implementing the new reserve regime. With reasons explained in the proposed framework, we have chosen to focus only on the short run production costs and implementation costs.

CONSULTATION

EMC invites the industry's feedback on this proposed CBA framework. All feedback and comments are to reach us by 31 Dec 2008.

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[1] Miguel A. Ortega-Vazquez, and Daniel S. Kirschen, ,*Optimizing the Spinning Reserve Requirements Using a Cost/Benefit Analysis, IEEE Transactions on Power Systems, VOL. 22, NO. 1, February 2007*

[2] R. Billinton and R. N. Allan, *Reliability Evaluation of Power Systems*.New York: Plenum, 1996.

PROPOSED COST-BENEFIT ANALYSIS METHODOLOGY

1 Background

Reserve is procured in the Singapore Wholesale Electricity Market (SWEM) to cover the loss of energy due to generation facility outages. The existing regime ensures that sufficient reserve is procured to cover the loss of any one generation registered facility (GRF) dispatched to provide energy. Hence, the quantity of required reserve is set based on the largest scheduled quantity from a single GRF.

Nevertheless, the Power System Operator (PSO) has identified situations where multiple GRFs could trip concurrently. Such situations are referred to as Multi-unit Contingencies (MUC). The PSO has thus proposed that the reserve requirement should be set at a level that is sufficient to cover such MUCs whenever such risks arise. On the one hand, augmenting the existing reserve requirement regime with the flexibility to alter reserve requirement to cover multi-unit contingencies (should the risk arises) enhances system reliability. On the other hand, this would incur (upon activation) a higher cost in the form of higher reserve requirement and thus higher reserve, energy and regulation prices. The industry's feedback from consultation is that some form of cost-benefit analysis (CBA) should be conducted to assess the viability of the proposal.

This note proposes a CBA framework for consideration.

2 CBA Methodology

Theoretical Framework

The benefit of the proposal is improved system reliability. This benefit arises from reduced likelihood of load shedding when multi-unit contingencies occur. The cost would be the associated wholesale market costs incurred to procure the extra reserve when there is a risk of any MUC.

We propose that CY 2007 be the assessment period for the CBA. The objective is then to estimate the net benefit of a reduction in load-shedding probability had the proposed reserve regime been in place throughout CY 2007.

Operational Framework

The idea is to first identify from 2007 the periods where there had been risk of multi-unit contingencies. Such risks are deemed to arise whenever the criteria for their activation are met. For all these periods, we calculate the value of reduction in the expected loss of load if the proposed reserve regime had been in place. We simulate the effects of the proposed reserve regime by writing it into the Market Clearing Engine (MCE) to compute the price/dispatch schedules for these periods.

The following sections explain in detail how benefits and costs associated with the proposal are quantified and compared.

2.1 Timeframe of Analysis

We propose that the timeframe for this study be the most recent calendar year.

2.2 Quantifying the Benefits:

Improved reliability means more reliable supply to consumers and lower likelihood of load shedding. The benefit of improved reliability can be measured by the change in Expected Energy Not Served (EENS). EENS is calculated using the products of Energy Not Served (ENS) under each contingency (i.e. outage of GRFs) and its corresponding probability of failure. The lower the EENS, the more reliable the system will be.

Table A4.1 Capacity Outage Probability Table and Calculation of EENS

S/N	Outage of GRFs (A)	Capacity on outage[3] (B)	Probability of failure[4] (C)	RR[5] (D)	ENS= Max{0,B-D} (E)	EENS= E x C (F)
	Outages of any single GRF[6]					
1	GRF1					
2	GRF2					
	…					
n	GRFn		SPF(n)			
	Independent Outages of any TWO GRFs					
n+1	GRF1 and GRF2		SPF(1) x SPF(2)			
n+2	GRF1 and GRF3		SPF(1) x SPF(3)			
	…		…			
$n+nC_2$	GRF(i)and GRF(j) {i, j <=n, i≠j}		SPF(i) x SPF(j)			
	…					
	Independent Outages of any THREE GRFs					
	…					
	Independent Outages of n GRFs		Π SPF[7]			
	Multi-unit contingencies					
N	GRFs in a MUC group		As indentified in 2.4.1b [8]			

[3] Energy and reserve scheduled by MCE for a GRF or GRFs.
[4] For outage of any single GRF, use the existing probability of failure of the GRF. For multi-unit contingencies, use the probability of failure for such contingencies provided by PSO (under 1.b of section 2.4)
[5] For Reserve Requirement (RR), it would be the scheduled (energy+reserve) of the largest risk setter as per MCE scheduled instead of the actual reserve requirement which has been discounted to account for the system response. In the original run, it is the largest scheduled (energy + reserve) of all individual GRFs. In the re-run, it is the largest scheduled (energy + reserve) of all individual GRFs or multi-unit contingency groups.
[6] Any GRF that is scheduled to provide energy.
[7] If GRFs under column A have been grouped into a type 1 MUC group, then its corresponding probability of failure under column C should be zero.
[8] For type 1 MUC, the probability of failure would be the sum of the probability of failure of all GRFs that have been identified as codependent.

$$EENS = \sum_{i=1}^{N} EENS_i$$

Table 1 illustrates how EENS is calculated using a capacity outage probability table (COPT)

[1]. COPT contains all the capacity outage states in the system and the probability of each state. By comparing the capacity on outage under each state and the reserve procured in the system, we would be able to assess the energy not served (ENS) under each state. Multiplied by its probability, the EENS of each state can be derived. The EENS of the system would be the sum of the EENS of all the capacity outage states.

Further, by multiplying the EENS with the Value of Lost Load (VOLL) which is measured in $/MWh, we will be able to value the benefit of the reliability improvement in dollar terms.

Benefit of reliability improvement	=	Δ (EENS x VOLL)	(1)

For VOLL, we propose using the value of S$6,160/MWh, which is Singapore's 2007 Gross Domestic Product (S$243,168.8Mil [9]) divided by the 2007 electricity consumption of 39,475GWh[10]. This value infers, on average, how much contribution to GDP each MWh of electricity makes.

2.3 Quantifying the Costs

2.3.1 Long Run Costs

In the long run, with the implementation of the proposed regime, extra capacity would be required to be built to meet the increased reserve requirement. An appropriate long run assessment of the cost would be the cost of maintaining enough capacity to meet the level of reserve requirement.

In Singapore's case, the reserve margin has consistently been over 70%. Our minimum reserve margin to maintain system security is 30%. In the Statement of Opportunities 2008 (SOO), the EMA stated that "If the reserve margin falls below the required 30% due to demand growth and/or plant retirements, this would be an indication that new investments in generation units are needed to maintain system security." In the SOO, the EMA also forecasted the reserve margin to be above 30% through 2016 under the base case load demand scenario. In light of this, it is unlikely that capacity would need to be added in order to meet additional reserve requirement in the foreseeable future.

[Note: When the reserve margin declines to the point where new capacity has to be added to maintain the reserve regime, there would be capacity investment costs incurred (at the prevailing cost at that time).]

Hence for the purpose of this CBA, we measure the short run costs that would have been incurred if the MUC regime was implemented in the study period (2007).

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[9] http://www.singstat.gov.sg/stats/themes/economy/hist/gdp2.html

[10] The annual consumption consists of the load settled through SWEM as well as those not settled through SWEM. The annual load settled through SWEM is 38,311GWh. There is also 332.4MW of installed embedded generation exempted from participating in the wholesale market and not settled through the market. It is assumed these generation plants were generating only 40% of the time, which is about 1164.73 GWh per year.

2.3.2 Short Run Costs

The short run cost refers to the increase in production costs, which are inferred directly from the value of the MCE's objective function. These costs are incurred when additional reserve due to MUC is required, and there is sufficient capacity to provide them.

Under the proposed regime, the production cost would generally increase due to the following reasons:

- Additional reserve would be cleared to meet the reserve requirement (which would typically result in higher reserve cost);
- The generation units that are part of an activated MUC would tend to be scheduled at lower generation and the difference will have to be met from less efficient generators (which would result in higher generation cost);
- Possible increase in regulation cost due to co-optimisation.

The SWEM employs a marginal pricing system. Under this system, the offer stacks would (approximately) reflect the marginal cost of producing generation/reserve/regulation. The total cost of production of energy, reserve and regulation can be derived from the net benefit (i.e. the value of the objective function of the linear program) using equation (2).[11]

Costs of Production	=	Purchase Bid Price x Demand – Net Benefit – Violation Penalties	(2)

The short run cost can be derived from the change in the production cost using equation (3) below.

Short Run Cost of reliability improvement	=	Δ Cost of Production	(3)
	=	Cost of Production – Cost of Production	

Further, the final cost should include the initial fixed costs required to implement the regime, which is currently being estimated.

2.3.3 Impact on Energy/Reserve/Regulation settlement

For additional reference, we will also estimate the changes to the following outcomes as a result of implementing the MUC regime in 2007.

a. Uniform Singapore Energy Price (USEP)
b. Regulation Price
c. Price and requirement for each class of reserve

These would be used to measure the costs incurred by the market participants in procuring energy, reserves and regulation in the real time markets. Note that these costs are not to be compared with the costs and benefits established in 2.2, 2.3.1

[11] Equation (2) is derived from the objective function of the MCE as defined in D.14.1 of appendix 6D of Market Rules, where it states that the objective value *Net Benefit* = *Purchase Bid Price* x *Demand* – (*Energy Cost* + *Reserve Cost* +*Regulation Cost*) – *violation penalty*. For a given dispatch period, *Purchase Bid Price* and *demand* are fixed parameters. *Net benefit* and *violation penalties* are the outputs of the MCE schedules.

and 2.3.2. They are shown here only to provide another perspective for the industry, which is familiar with these costs.

2.4 Step-by-Step Procedure

Step 1: PSO to identify all probable MUCs in 2007, providing the following information for each of them:

1.a. The GRFs that will trip in the multi-unit contingency
1.b. The probability of failure for each multi-unit contingency
1.c. Record of the dispatch periods that the multi-unit contingency was considered probable according to the criteria set by PSO

For each dispatch period in which any MUC is considered probable, carry out steps 2 to 6 to determine whether reserve requirement should be raised to cover such a MUC.

Step 2: Retrieve the original price/dispatch schedules for this dispatch period. Calculate the **Cost of Production$_{\textbf{original}}$** with Eqn (2). Construct Table 1 according to the generation schedules and calculate **EENS$_{\textbf{original.}}$**

Step2: Modify the MCE to include the following constraint in the optimisation:

Reserve Requirement is no less than:

- the risk[12] of any multi-unit contingency that are considered probable in the dispatch period); and
- the risk of any single GRF

Step 3: Re-compute with the modified MCE for each dispatch period identified in 1.c.In this re-run, input data [13] such as the load demand, generator offers and grid conditions would be the same as those used for the original run.

Step 4: Calculate **Cost of Production$_{\textbf{rerun}}$** and **EENS** with the price/dispatch schedules in the re-run schedules.

Step 5: Calculate the **Cost** and **Benefit** of the new solution for each dispatch period using the following formula:

$$\text{Benefit of reliability improvement} = (EENS_{original} - EENS_{rerun}) \times VOLL$$

$$\text{Cost of reliability improvement} = \text{Cost of Production}_{rerun} - \text{Cost of Production}_{original}$$

Step 6: Calculate the **accumulated cost** and **accumulated benefit** by summing up the cost and benefit calculated for all dispatch periods within the assessment period. Any calculated fixed cost (to introduce the new regime) shall be added to the final accumulated cost.

[12] The risk will take into account of the system response, i.e. scheduled (energy + reserve) of all GRFs affected in the multi-unit contingency minus power system response.

[13] When consecutive dispatch periods are identified in 1.c, for the first dispatch period, the initial loading status of generators would be the same as that in the original run. For each subsequent dispatch periods, the initial loading will be determined based on the schedules (produced by the modified MCE) of the immediate preceding dispatch period as the starting status of generators. This is to simulate the sequential effect of the proposed regime.

3 Assumptions and Limitations

3.1 Choice of VOLL

An average economic value (which is annual GDP divided by annual electricity consumption) is assigned as VOLL.

The actual VOLL could be lower because

- in reality, the actual load shedding can be arranged to target loads with less than average economic value.
- the value of lost load cannot be recovered by consumption at another time in some cases.

However, there could also be additional cost associated with unexpected load shedding. The negative impact of random interruption of electricity supply could be much higher than the average economic value.

3.2 Estimate of EENS

It is assumed that energy not served exactly matches the shortfall in reserve.

In reality, the load shedding will occur in blocks. Hence the method could underestimate the loss of load. On the other hand, the actual energy shortage could be smaller due to the system response.

3.3 Assumption for the simulation run

All input data are assumed to be the same. In reality, it is very likely that Gencos' (especially those whose generators are grouped into any MUC) offers would change, which could significantly change the simulation result.

Reference

[1] R. Billinton and R. N. Allan*, Reliability Evaluation of Power Systems*.New York: Plenum, 1996.

[2] *Statement of Opportunity for Electricity Industry 2008*, Energy Market Authority www.ema.gov.sg

Annex 5 Slides on “Reserve Requirement & Multi-Generating Units Tripping”

RESERVE REQUIREMENT
&
MULTI-GENERATING UNIT TRIPPING

23 Jan 08

ENERGY MARKET AUTHORITY

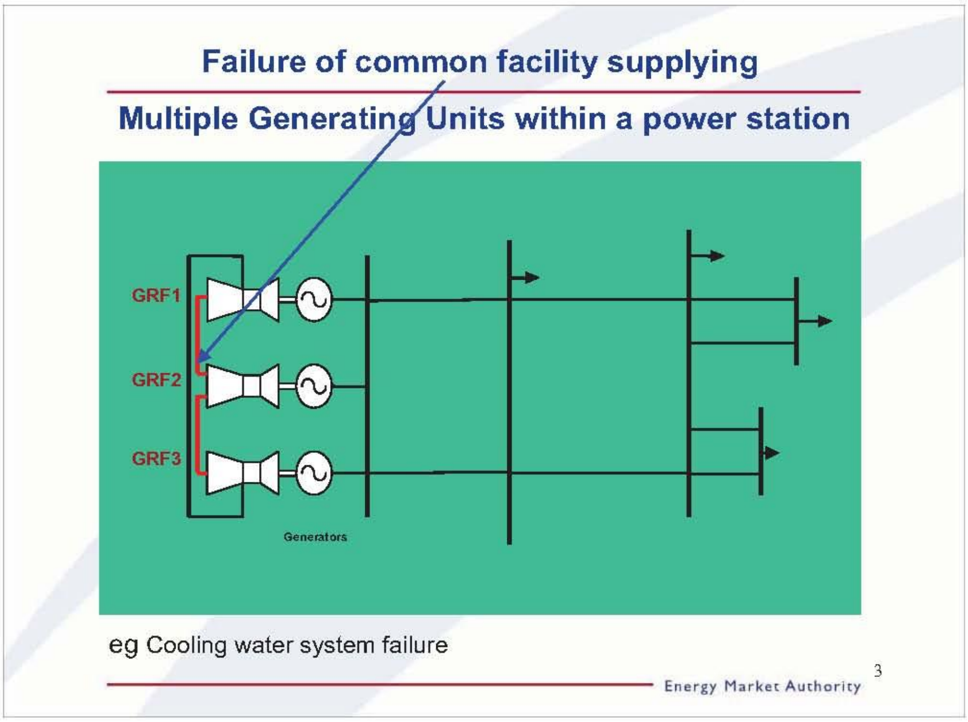
1

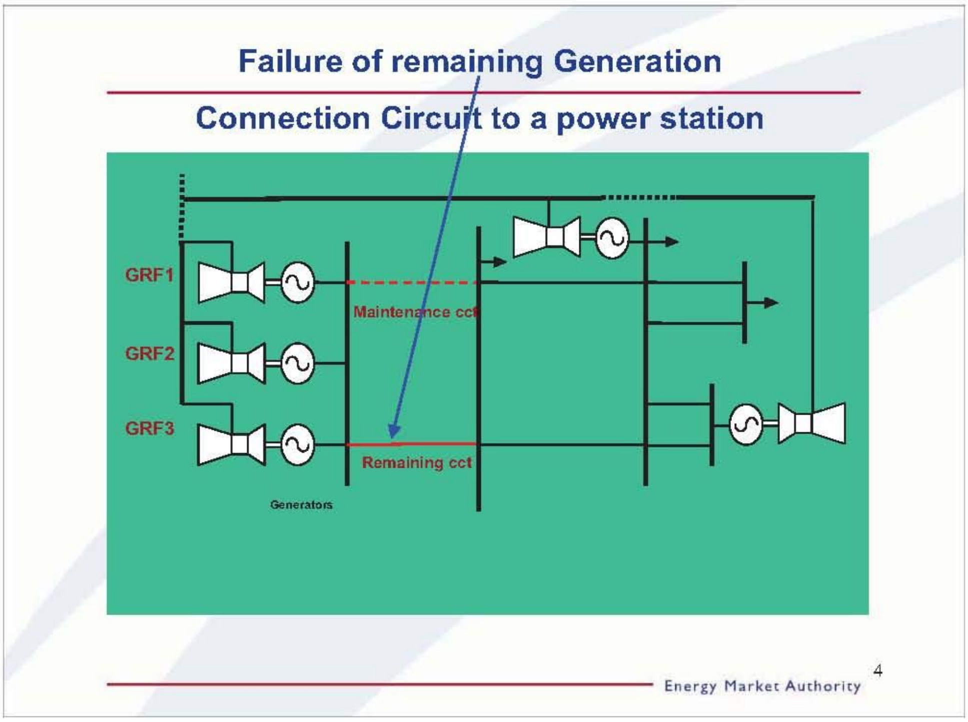
INTRODUCTION

- Currently, the Reserves scheduled by the MCE only cater for the loss of **single** largest generation facility
- There are single contingency events that can cause tripping of multiple generating units. This can result in widespread Blackout
- Hence, there is a need for MCE to schedule sufficient reserves to cater for loss of multiple generating units whenever these risks are present.
- The following diagrams illustrate some possible scenarios that could lead to tripping of multiple generating units :-

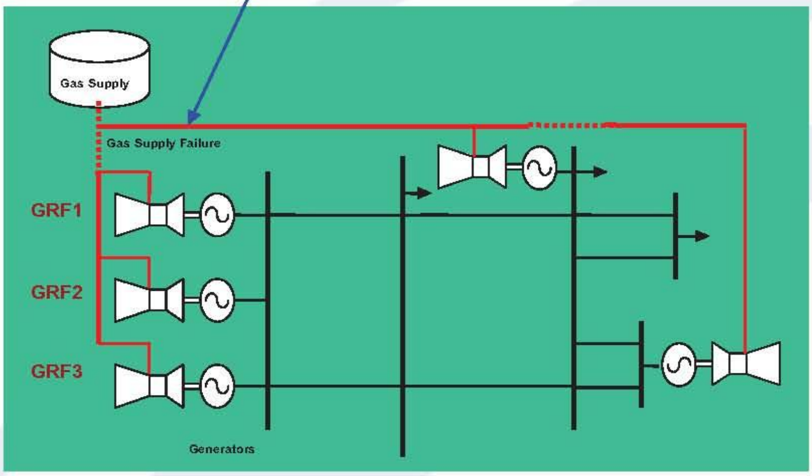
Energy Market Authority

2


Failure of common facility supplying
Multiple Generating Units within a power station
GRF1
GRF2
GRF3
Generators
eg Cooling water system failure
Energy Market Authority
3


Failure of remaining Generation
Connection Circuit to a power station
GRF1
GRF2
GRF3
Maintenance cct
Remaining cct
Generators
Energy Market Authority
4

Failure of common gas supply to power stations



eg when ORF/Genco receiving stn has one of the two streams out-of-service

Energy Market Authority 5

Options Available

Current Arrangement: PSO can increase Risk Adjustment Factor whenever any of the above multi-units trip risks are present. MCE increase Reserve scheduled by the RAF.

Disadvantages:

1. Reserve requirement is increased globally, ie not targeted at the generating units having higher risk.
2. Unable to predict accurately schedule energy & reserve of the specified generating units. eg MCE will still schedule higher reserve even if a specified unit is not scheduled to provide energy.
3. More likely to have Reserve price spike if the RAF is high and the System doesn't have sufficient Reserve offer.

Energy Market Authority 6

Options Available

Proposed Arrangement: PSO inform EMC which are the generating units contributing to multi-unit tripping risk. MCE group the relevant units and co-optimise the energy & reserve schedule for all units.

Advantages:

1. Reserve requirement is targeted at the group of highest risk generating units.
2. Reserve schedule is dynamically determined by the MCE depending on the energy schedule of the relevant units. ie if one of the specified units is not scheduled to provide energy, the overall reserve schedule would be lowered.
3. Co-optimisation will ensure that energy scheduled of relevant units can only be as high as Reserve available to cover the risk, while optimising the trade-off between cost of Energy provide by the relevant units vs Reserve cost.

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Moving Forward

- ✓ PSO is currently working with EMC on the propose market rules change.
- ✓ EMC will consult Market Participants once the draft is readied.
- ✓ EMC will table finalised rules change to RCP for endorsement.
- ✓ EMC Board will decide whether to endorse RCP's recommendation.
- ✓ EMC will submit to EMA for approval once endorsed by EMC Board.

In the meantime, PSO may increase Risk Adjustment Factor whenever any of the above multi-units trip risks are present.

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Annex 6 Computation of VoLL

In the Proposed CBA Methodology Paper, it is proposed that the Value of Lost Load (VoLL) be calculated using Singapore's Gross Domestic Product divided by the annual electricity consumption of the corresponding year.

The VoLL calculated for each year of the period of study is shown in Table A5.1 below.

Table A5.1 VoLL for Year 2003-2008

Year	**GDP[1]**	**Load settled through SWEM**	**Embedded Load**	**VoLL Value (including Embedded Load)**
2003	$162.382 bn	32578 GWh	2975.553 GWh[2]	$4567/MWh
2004	$185.365 bn	32805 GWh	2975.553 GWh	$5181/MWh
2005	$201.313 bn	35628 GWh	2975.553 GWh	$5215/MWh
2006	$221.143 bn	36724 GWh	2975.553 GWh	$5570/MWh
2007	$251.610 bn	38311 GWh	2513.737 GWh[3]	$6163/MWh
2008	$257.419 bn	38900 GWh	2183.868 GWh	$6266/MWh

[1] http://www.singstat.gov.sg/stats/themes/economy/hist/gdp2.html
[2] Based on "The Electricity (Electricity Generation and Retail Licence)(Exemption) Order (O1)", 452.9MW of embedded generation was exempt from participating in the SWEM from 1 Jan 2002 to 31 May 2007, assuming these embedded generators were generating 75% of the time.
[3] Based on "The Electricity (Electricity Generation and Retail Licence)(Exemption) Order 2007", with effect from 1 June 2007, 332.4MW of embedded generation is currently exempt from participating in the SWEM, assuming these embeded generators were generating 75% of the time.

Annex 7 Response to Market Participants' comment to CP 17(with CBA results) published on 25 Nov 2009

Comments from Market Participants	EMC/PSO's response
Keppel Merlimau Cogen	
General 1) Singapore operates one of the most reliable power supply system globally. The consequence of implementing the MUC risk proposal will lead to all consumers in Singapore bearing even higher electricity prices despite the current high levels of reliability. The wider national interest to provide reliable and competitively-priced electricity for foreign investments, and hence employment creation, need to be weighed objectively.	
2) Implementation of MUC will not only lead to significant increase in reserves requirement and prices but also changes to gencos' bidding strategy. This should warrant a review of the current co-optimisation mechanism within the MCE to ensure that the application of MUC in the current MCE framework is feasible and fair.	EMC: The proposal would not change the principle of how co-optimisation mechanism in the MCE should work and therefore a review is not necessary.
3) The computation of generating units' SPFs should also be reviewed in greater details with the implementation of MUC to ensure that gencos of all configuration types are not doubly penalized in a MUC risk event.	EMC: We will look into SPF methodology and determine if it should be changed if RCP decides to support implementing the proposal.
CBA ***4)*** The CBA assumes no change in market behavior and utilizes only 3 historical MUC cases identified by PSO, with one dating as far back as 2003. In the 5 years used for the study, it appears that only 1 case of each risk type has been identified. We would suggest that, not withstanding a more comprehensive analysis, an analysis incorporating more recent data points be used for review of the proposal to better reflect the present market dynamics.	EMC: The CBA was to be conducted based on actual MUC cases that had met the activation criterion for the 3 types of MUC during 2003 to 2008. Only these three cases were provided by PSO. The study period used for the CBA and the assumptions and limitations of the CBA were already explained in the proposed CBA methodology paper published by EMC. We do not believe that additional analysis based on new cases would enhance the CBA analysis.
5) The CBA employed the RAF method as a comparison against the MUC method. As detailed in Annex 4 of the paper, the proposed methodology for comparing MUC against RAF is not utilized or tested by actual markets, hence the realized outcomes from the simulation run is not proven.	EMC: Disagree. The comparison of the MUC method against the RAF method was based on actual cases ie they are based on actual market.

Comments from Market Participants	EMC/PSO's response
6) The current determination of RAF and criteria for activation is not transparent; a comprehensive understanding of the current application is crucial for all stakeholders before an objective review of the CBA can be conducted. 7)	PSO: PSO will arrange a suitable forum to brief MPs on the setting of the RAF.
Type 1 8) We seek PSO's detailed description of Type 1 Risk and provision of another real example (other than that relating to a 2-2-1 plant type configuration) to further exemplify the determination of such risk type.	PSO: Type 1 risk also includes any plant configuration where any shared element failure could result in tripping of multiple GRFs. For example, cooling water system failure resulting in tripping of multiple GRFs within a power station.
9) The procedures and criteria for activation of any MUC risk have yet to be provided with sufficient details for review. Such information is essential to ensure that the implementation process envisaged is viable and objective. Similarly, the procedures and criteria adopted by PSO to decide on the de-activation time should be made transparent to Market Participants to ensure fair play in a liberalized market place.	EMC: Other than the lead time that PSO needs to give to the market and who should receive what information, other details (e.g. What constitutes the 3 types of Multi-unit contingency; the activation criteria; what information needs to be provided for activation; who bears the reserve cost and how the SPF would be computed) are already explained in the concept paper.
10) The paper assumes that gencos are the party best able to manage risks not caused by them, i.e. 'de facto causer pays principle', when no such 'de facto authority' applies to gencos to manage transmission licensee's or gas transporters/suppliers maintenance schedule. This flawed rationale of the causer-payer principle will only promote biasness and inefficiency in the market. The de-link of the gas and electricity market should not encourage the 'convenience' of transferring costs to gencos, i.e. in the case of Type 3 risk. As mentioned previously, integration and reinforcement of the gas network is necessary to address such risks.	EMC: For MUC risk caused by the transmission licensee's asset, the reserve cost would be borne by the transmission licensee. For MUC Type 3 risk caused by the failure of ORF or the gas metering facility (i.e. the gas supplier/transporter's assets), we would ask RCP to consider writing to EMA to see whether possible to address such risk as suggested. If EMA decides it is not possible, the reserve cost would be allocated based on method as proposed in the concept paper.
Sembcorp Cogen	
For CP 17, no further comments from Sembcorp. It was submitted in good faith and we hope PSO and EMC would consider reviewing the SPF computation together with our previous comments	EMC: We will look into SPF methodology and determine if it should be changed if RCP decides to support implementing the

Comments from Market Participants	EMC/PSO's response
for this concept paper. Agree that we need not revisit SPF computation if the market design remains status quo.	proposal.
Senoko Power	
CP17: MODELLING OF MULTI-UNIT CONTINGENCY RISK We refer to the above paper and the subsequent clarification meeting held on 2 December 2009. The proposal remains fundamentally unchanged from the first in 2008; hence, the comments made by Senoko in August 2008 and our further clarification in January 2009 still apply.	
Cost-Benefit Analysis (CBA) It is unclear from the description of the CBA whether the three cases considered are "sample" cases or the only times that MUC risks were present in the period 2003-2008. Nonetheless, it is clear that there is a strong net cost associated with the proposal. In light of this analysis, it does not appear desirable to progress this concept paper to the rule change proposal stage.	EMC: The CBA was to be conducted based on actual MUC cases that had met the activation criterion for the 3 types of MUC during 2003 to 2008. Only these three cases were provided by PSO.
Proposed mechanism would need other industry changes to be effective. If, for whatever reason, it was decided to continue to develop the proposal, Senoko considers that the following supporting changes would need to be made to the way the electricity and gas industries currently function for the proposed MUC mechanism to work effectively: 1. The parties responsible for creating each risk type should bear any associated reserve costs. To achieve this first best design principle, the EMA should ensure that the transmission licensee and the gas transporter pay reserve costs when their action gives rise to risk types 2 and 3 respectively.	EMC: For MUC risk caused by the transmission licensee's asset, the reserve cost would be allocated to the transmission licensee. For MUC Type 3 risk caused by the ORF or the gas metering facility (i.e. the gas supplier/transporter's assets), we would ask RCP to consider whether necessary to write to EMA to see whether possible to address such risk as suggested. If EMA decides it is not possible, the reserve cost would be allocated based on method as proposed in the concept paper.

Comments from Market Participants	EMC/PSO's response
2. Gencos should receive additional detailed information regarding type 2 and type 3 risks from the respective asset owners and operators. This information is necessary for gencos to manage the MUC risks in the manner suggested in the consultation paper.	EMC: If RCP decides to support implementing this proposal, EMC would consult Senoko on what information is required from which asset owners /operators and whether it is possible to make it available.
3. The PSO and GSO should have specific responsibilities to ensure that MUC risks are considered and minimised when they take action (e.g., co-ordination and approval of maintenance schedules),	PSO: Co-ordination of maintenance activities are already in-place. However, Type 3 scenario refers to mitigation actions that only Gencos could have taken to minimise impact of gas disruption to its GRFs – please refer to detail descriptions in the paper.
Coordination of Maintenance Planning Further to the three points listed above, the concept paper states that "gencos can coordinate with gas suppliers and gas transporters" on maintenance schedules assumes that gas suppliers and gas transporters would be amenable to such "coordination" with gencos. The reality is these parties are under no obligation to accede to such requests from gencos. The only party in the regulatory regime that has oversight of and directing powers over these parties is the EMA. Senoko appreciates the opportunity to comment on the concept paper.	EMC: For MUC Type 3 risk caused by the failure of ORF or the gas metering facility (i.e. the gas supplier/transporter's assets), we would ask RCP to consider writing to EMA to see whether possible to address such risk as suggested. If EMA decides it is not possible, the reserve cost would be allocated based on method as proposed in the concept paper.

Annex 8 Simulation results for May 2010 Type 1 MUC case

Table A8.1 CBA results for Primary-MUC scenario and No-RAF-No-MUC scenario

	Primary-MUC against Base RAF Method	No-RAF-No-MUC against Base RAF Method.
Increase in Cost of Production	S$358,028.09	−S$19,007.51
Reduction in EENS	101.39 MWh	− 3.61 MWh
Benefit	S$652,520.42	−S$3,203.06
Cost per MWh of EENS prevented	S$3,531.34 / MWh	S$5,272.25 / MWh
Net Benefit	S$294,492.33	−S$4,195.55

Table A8.2 Impact on prices and dispatch schedules under "Primary-MUC" scenario

	Average (as in Base RAF method)	Average (Primary-MUC)	Average Increase		Max Increase	Min Increase
USEP ($/MWh)	173.01	181.74	8.73	5.05%	84.58	-21.24
Pri Res Rqmt (MW)	246.09	303.59	57.49	23.36%	210.24	-59.19
Sec Res Rqmt (MW)	248.06	254.31	6.25	2.52%	52.65	-30.52
Con Res Rqmt (MW)	523.17	533.02	9.85	1.88%	78.98	-23.93
Energy Schedule of MUC (MW)	487.33	474.50	-12.83	-2.63%	0.00	-143.76
Pri Res Price ($/MWh)	10.79	79.37	68.58	635.80 %	220.22	-105.16
Sec Res Price ($/MWh)	0.19	0.17	-0.02	-12.29%	1.02	-1.02
Con Res Price ($/MWh)	0.43	0.44	0.01	2.22%	2.84	-0.41
Reg Price (S/MWh)	65.55	70.69	5.14	7.85%	133.96	-25.46

Table A8.3 Impact on prices and dispatch schedules under “No-RAF-No-MUC” scenario

	Average (as in Base RAF Method)	Average (No-RAF-No-MUC)	Average Increase		Max Increase	Min Increase
USEP ($/MWh)	173.01	172.11	-0.90	-0.52%	1.44	-21.23
Pri Res Rqmt (MW)	246.09	172.19	-73.90	-30.03%	0.00	-152.32
Sec Res Rqmt (MW)	248.06	249.24	1.18	0.48%	27.58	0.00
Con Res Rqmt (MW)	523.17	524.47	1.30	0.25%	32.17	-0.55
Energy Schedule of MUC (MW)	487.33	487.47	0.14	0.03%	10.98	0.00
Pri Res Price ($/MWh)	10.79	0.01	-10.77	-99.89%	0.00	-105.23
Sec Res Price ($/MWh)	0.19	0.22	0.03	14.72%	1.02	0.00
Con Res Price ($/MWh)	0.43	0.47	0.03	7.25%	2.84	0.00
Reg Price (S/MWh)	65.55	65.02	-0.53	-0.81%	7.69	-25.46