Notice of market rule modification

Paper No.	EMC/RCP/22/2005/244
Rule reference:	Appendix 7A/Section A.2 Chapter 6/Section 10.3 Chapter 7/Explanatory note before Section 3.2
Proposer:	Market Administration, EMC
Date received by EMC:	5 August 05
Category allocated:	2
Status:	Approved by EMA
Effective Date:	9 February 06

Summary of proposed rules change:

This rule change modifies the basis of allocating reserve cost among generators from their metered injection energy quantity (IEQ) to their scheduled energy (from the real-time dispatch schedule).

Date considered by Panel:	12 September 05
Date considered by EMC Board:	29 September 05
Date considered by Energy Market Authority:	14 November 05

Proposed Rule Modification:

Refer to attachment

Reasons for rejection/Reasons for referral back to Panel (if applicable):

PAPER NO.	:	**EMC/BD/05/2005/07(c)**
RCP PAPER NO.	:	**EMC/RCP/22/2005/244**
SUBJECT	:	**ALLOCATION OF RESERVE COST**
FOR	:	**DECISION**
PREPARED BY	:	**JANICE LEOW** **ANALYST**
VETTED BY	:	**PAUL POH LEE KONG** **SVP, MARKET ADMINISTRATION**
DATE OF MEETING	:	**29 SEPTEMBER 2005**

Executive Summary

This paper assesses EMC's rule modification proposal to change the basis used in allocating reserve cost to generators from their metered injection energy quantity (IEQ) to their scheduled energy (from the real-time dispatch schedule). Allocating reserve cost using IEQ was seen as inequitable because generators that contribute to system security by providing more generation may be penalised with a larger share of reserve cost. The proposed change would result in a more efficient and equitable allocation of reserve cost as there is a closer match of cost to causer and generators pay for the reserve they create the need for. It would also provide generators an incentive to revise offers following a forced outage. The estimated time required to implement the required changes to the settlement IT system is two months.

The RCP recommends that the EMC Board **adopt** this proposal.

1. Introduction

As part of establishing a yearly work plan for the Rules Change Panel (RCP) in 2003, EMC met with market participants to identify and incorporate stakeholder concerns.

It was noted that, in general, the larger is a generator's metered injection energy quantity (IEQ) relative to that of other generators, the larger is its share of reserve cost. Therefore, a generator that responds to a need for increased generation will have a larger IEQ and may consequently be allocated a larger share of reserve cost than would otherwise have been the case. This is seen as inequitable because generators that contribute to system security by providing more generation are penalised. Hence, market participants expressed the need for the EMC to review whether IEQ is the right basis for allocating reserve cost in the Singapore wholesale electricity market.

This paper assesses EMC's rule modification proposal to change the basis used in allocating reserve cost to generators from their IEQ to their scheduled energy (from the real-time dispatch schedule). Section 2 briefly describes reserve in the Singapore wholesale electricity market. Section 3 evaluates the use of IEQ as the basis for allocating reserve cost against the design principles of the market and proposes an alternative basis that aligns reserve cost allocation with the said principles. Section 4 concludes. Sections 5 and 6 describe the impact on market systems and the implementation process.

2. Reserve in the Singapore wholesale electricity market

Reserve is generation or load reduction capacity that can be called upon to replace or augment scheduled energy in a contingency. There are three classes of reserve: primary, secondary and contingency, which must be available within 8 seconds, 30 seconds and 10 minutes of being called upon, respectively.

2.1. Determination of the reserve requirement

The N-1 contingency principle is employed in determining the quantity of reserve required. This means the quantity of reserve required is that which is sufficient to cover the loss due to the failure of any one generator. By necessity, the reserve required must be sufficient to cover the loss in the largest possible single contingency, defined as the loss of the largest primary contingency unit (PCU) with the consequent loss of all secondary contingency units (SCUs)[1].

For each dispatch period, the effective scheduled reserve[2] required for each class of reserve is determined based on the scheduled energy and effective scheduled reserve[3] of generators, and the modelled power system response[4] to a drop in frequency (see full specification in Appendix 6D.17 of the Market Rules).

The following illustrates how the reserve requirement for primary reserve is determined. The result may be further scaled by the risk adjustment factor set by the PSO. The reserve requirements for other classes of reserve (secondary and contingency) are determined similarly.

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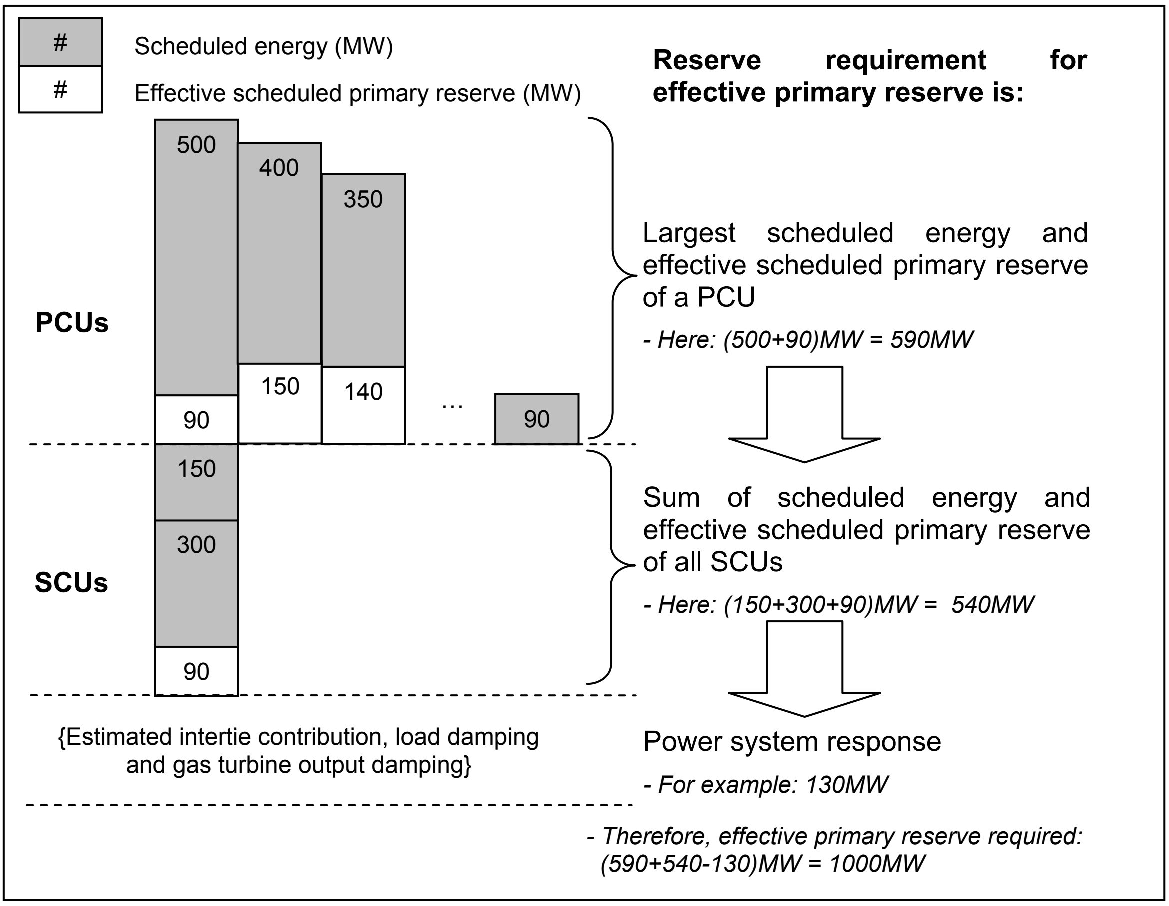
[1] There are currently no SCUs in the Singapore wholesale electricity market.

[2] Effective scheduled reserve is scheduled reserve scaled by the estimated effectiveness of the units in providing reserve.

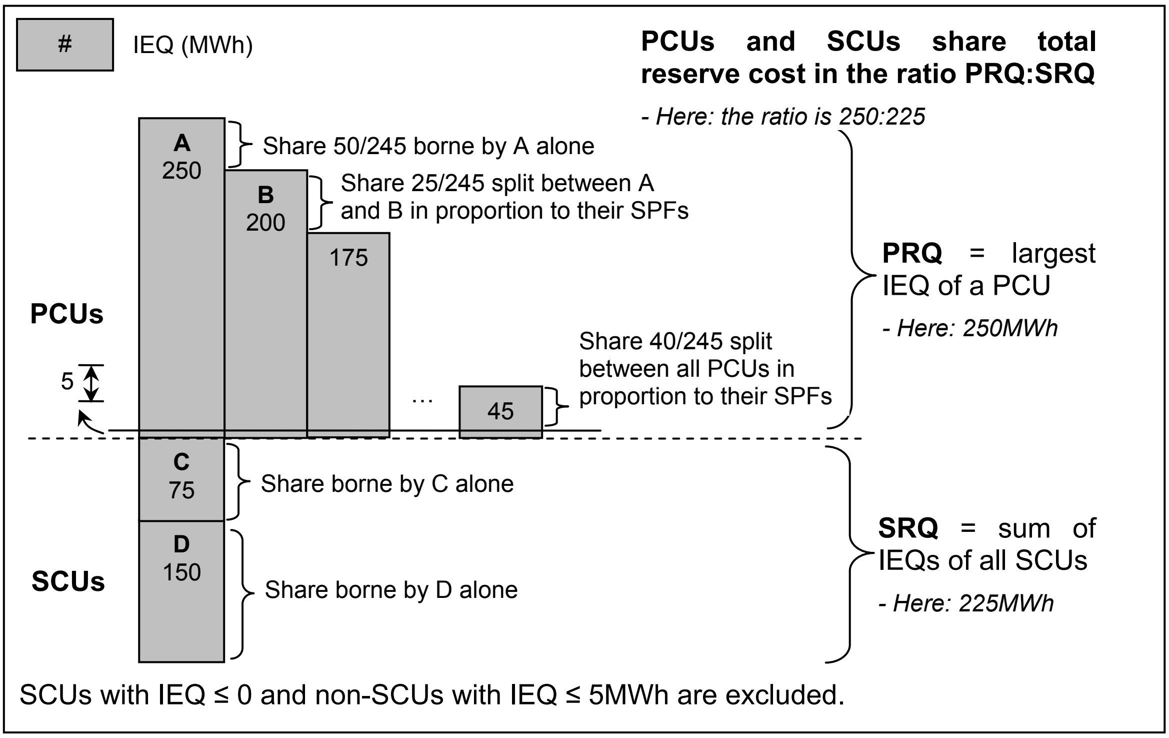
[3] Scheduled reserve is included because a generator's scheduled reserve can be used to cover the failure of other generators but not that of its own.

[4] Power system response consists of estimates of the following due to a drop in frequency: (1) Intertie contribution – increase in energy supply though the intertie with Malaysia; (2) Load damping – automatic reduction in load; (3) Gas turbine output damping – reduction in gas turbine output.



2.2. Allocation of reserve cost

In each dispatch period, total reserve cost is wholly allocated to generators based on their IEQs and standing probabilities of failure (SPFs) as follows (see Annex 1 for details).



The method of allocating reserve cost among PCUs in incremental tiers as shown above is known as the modified runway formula. Non-SCUs with IEQ ≤ 5MWh do not pay for reserve as it is assumed that their failure would not have triggered a contingency response requiring reserve. They share the cost of regulation.

The use of IEQ as the basis for allocating reserve cost as described is the issue that is addressed in this paper.

3. Analysis

3.1. Cost allocation principles

The Singapore wholesale electricity market design is based on the basic principle of economic efficiency[5]. Amongst other things, this calls for those that cause costs to face the costs they cause. This is known as the causer-pays principle. It results in efficient cost allocation because it creates incentives for cost minimisation by allocating costs to parties that are able to reduce them.

As cost allocation is an issue of distribution, the principle of equity and fairness is also relevant. But in line with the design of the wholesale electricity market, equity and fairness are secondary and are only considered insofar as they result from the incorrect application of economic theory.

3.2. Using IEQ as basis for allocating reserve cost

<u>Deficiencies</u>

Compared against the market's design principles the use of IEQ as the basis for allocating reserve cost is inefficient and inequitable.

Recall (see section 2.1) that the reserve requirement was determined based on the scheduled energy and reserve of generators, not their IEQs. Thus, IEQ is not a measure of how generators created the need for reserve, and allocating reserve cost based on IEQ under the current allocation method is inconsistent with the causer-pays principle for efficient cost allocation.

Reserve cost is allocated inequitably because generators that create the same need for reserve (by virtue of having equal scheduled energy), will typically be allocated different shares of reserve cost as they are likely to have different IEQs[6]. Moreover, when a generator trips, it is allocated a smaller share of reserve cost for the period, even though it caused the contingency that reserve was procured to cover, leaving each of the remaining generators with a greater share of reserve cost. Further, generators that contribute to system security by providing increased generation are penalised with a greater share of reserve cost when they provide further output (such as when constrained on) in a contingency.

<u>Reasons for current design</u>

Whilst we have no documentation justifying the choice of IEQ as the basis for allocating reserve cost in the Singapore wholesale electricity market, we consider the following to be plausible explanations:

- A generator's IEQ is representative of the reserve that would have been required from reserve providers to cover the risk of that generator in the dispatch period.

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

[6] This can be due to a variety of reasons, such as the generators having supplied different amounts of regulation.

- IEQ was used in the Singapore Electricity Pool, which preceded the current market.

IEQ is an average energy value, whereas reserve is scheduled to cover spot risk. Hence, IEQ does not correspond to the risk that reserve is scheduled to cover and thus does not correspond to how reserve cost is incurred. Since the cost of reserve was incurred based on expected need (from scheduled quantities), not actual need, the allocation of reserve cost should likewise be based on expected rather than actual need.

3.3. An alternative basis for allocating reserve cost

In line with the causer-pays principle, efficient allocation of reserve cost would require parties to be allocated the cost of the reserve that they create the need for. Although it is unlikely that any method of allocating reserve cost can perfectly reflect the drivers of the reserve requirement, the allocation method used should improve economic signalling.

To match reserve cost to the way that the reserve requirement is determined, efficient allocation of reserve cost would imply the following.

Characteristic	Rationale
1. Allocation based on scheduled energy (from the real-time dispatch schedule)	Scheduled energy is the main determinant of the reserve requirement.
2. Allocation to each SCU the full cost of the reserve necessary to protect against its own outage	As the largest single contingency is assumed to include the failure of all SCUs, each SCU creates the need for additional reserve corresponding to its own failure.
3. Allocation of the remaining reserve cost to PCUs via the modified runway formula (applied to scheduled quantities)	Unlike the case for SCUs, reserve is shared between PCUs: the reserve required to cover the failure of PCUs is defined as a single quantity that covers the failure of any one PCU. As their scheduled energy differ, PCUs do not all require the same amount of reserve. The modified runway formula allows the cost of incremental reserve to be allocated only between PCUs that create the need for it, and allocated according to their likelihood of requiring it to incentivise unit maintenance for reliable operation.

A full specification of this alternative basis for allocating reserve cost is given in Annex 2. This differs from the current basis in that allocation is based on scheduled rather than metered quantities.

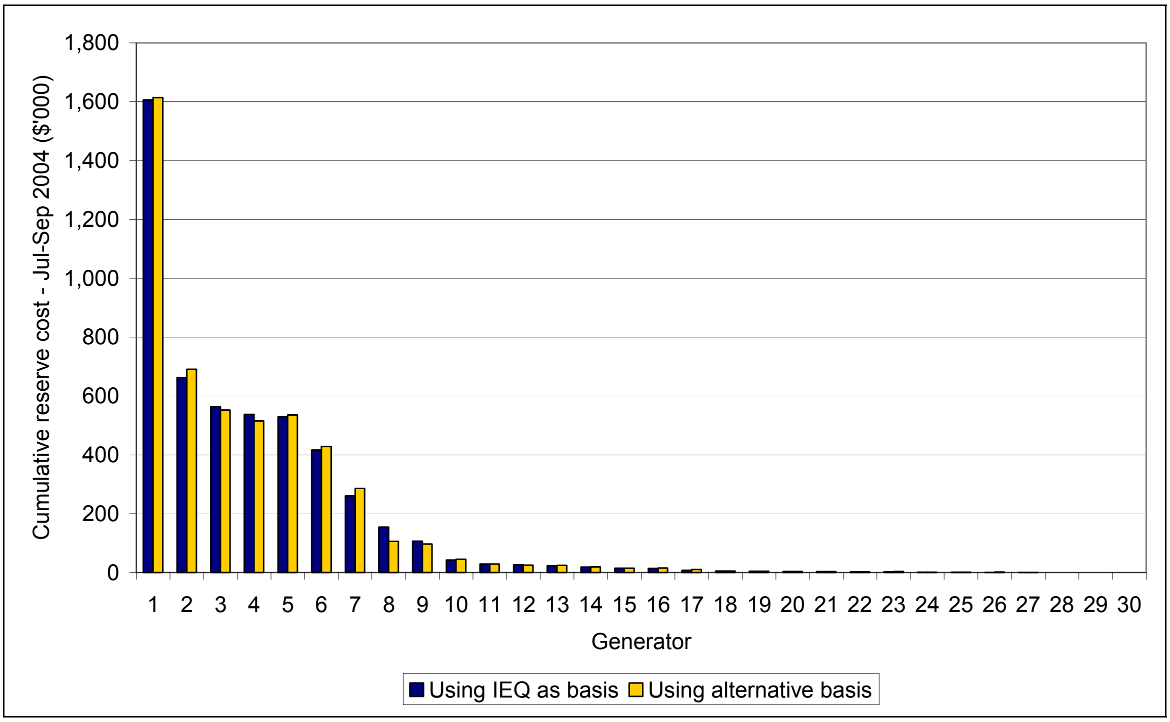
The implications are as follows.

Benefits	Costs
• More efficient allocation of reserve cost by closer matching of cost to causer. • Equitable as generators pay for the reserve they create the need for: • Generators that create the same need for reserve pay the same amount for reserve.	• The cost of modification to the settlement IT system is estimated to be $69,000.

Benefits	Costs
• Generators that trip continue to pay their share of the cost of reserve procured to cover their risk of outage in that period. Other generators will pay for reserve according to the need they created for reserve in that period. • Generators are not penalised for responding to the need for increased generation in a contingency.	

Comparison of reserve cost allocations

Using data from 4410 periods from July to September 2004 (excluding 6 re-run periods), the allocation of reserve cost using the alternative basis was calculated. The following shows how this compares with using IEQ as the basis for allocation (see Annex 3 for actual figures).



The maximum increase in cumulative reserve cost for any one generator over the quarter was $28,884, and the maximum decrease was $47,968. These are indications of the extent to which reserve cost is allocated inefficiently and inequitably under the current method.

As this comparison does not take into account the ability of generators to respond to a change in the reserve cost allocation basis, the differences do not indicate the degree to which generators' allocated reserve cost will be increased or decreased using the alternative basis. Rather, improved economic signalling using the alternative basis for allocating reserve cost will allow generators to better recognise the cost of reserve attributable to each and to vary their offers accordingly.

The same variation in reserve cost allocations over a year would mean that reserve cost could be allocated inefficiently up to the order of $192,000 (≈ $47,968 × 4) a year for a single generator.

The financial impact of the change in allocation basis for four forced outages was also considered. The examples showed that the allocation of reserve cost based on scheduled energy would provide generators an incentive to revise offers following a forced outage and would not discourage generators from responding to a contingency.

Other considerations

The current allocation of reserve cost using IEQ provides (some) disincentive against generators' generating in excess of their scheduled quantities. This is because although excess generation would bring greater revenue from the energy market, the generator may consequently be allocated a larger share of reserve cost. Allocation of reserve cost using the alternative basis removes this disincentive as reserve cost allocations are fixed ex ante to the trading period.

The incentive to over-generate depends on the prevailing energy price and is an incentive that already exists. However, in the Singapore wholesale electricity market, the opportunity to over-generate is limited because most generators operate under automatic generator control (AGC) for output levels at and beyond minimum stable load.

When a generator is not on AGC and its recorded output is 10MW more or less than the scheduled/instructed target MW value at the end of the dispatch period, the generator is non-compliant with dispatch instruction under the System Operation Manual. Non-compliance with dispatch instruction is a breach of the Market Rules. As it is the role of the Market Surveillance and Compliance Panel (MSCP) to enforce the Market Rules, it is appropriate for non-compliance with dispatch instructions to be dealt with directly by the MSCP in a swift and decisive manner to discourage such behaviour, rather than indirectly by inefficiently allocating reserve cost.

4. Conclusion

As IEQ is currently used as the basis for allocating reserve cost, it does not correspond to the way generators create the need for reserve and generators may be allocated larger shares of reserve cost for providing additional output during a contingency. Hence, the current reserve cost allocation basis is inefficient and inequitable.

These deficiencies are addressed by allocating reserve cost using the scheduled energy of generators as described in section 3.3 and Annex 2. The one-off cost of the required modification to settlement IT systems is small (about 36%) compared to the degree of inefficiency and inequity that is corrected each year with such a change.

5. Impact on market systems

For the proposed change to be implemented, EMC's settlement IT system must be modified to change the basis used to allocate reserve cost amongst generators from their IEQ to (½h) times their scheduled energy (from the real-time dispatch schedule)[7].

6. Implementation process

The estimated time required is two months: one month for development and one month for user acceptance testing. As stated earlier, the estimated cost is $69,000.

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[7] This is an alternative but equivalent specification to that in Annex 2 because the convention in settlement is for quantities to be given in MWh.

7. Plain language drafting

In drafting the changes to the Market Rules that are necessary to implement this rule modification proposal, EMC has taken the opportunity to introduce improved drafting to the Market Rules.

EMC has redrafted the affected sections of the Market Rules and sections that relate to the subject of the rule modification proposal, in line with plain English drafting principles to improve the readability of the Market Rules.

8. Consultation

An earlier version of the concept paper (RCP Paper No. EMC/RCP/21/2005/CP09), which this rule change originates from, was published on the EMC website for comments.

In that version, it had been proposed that reserve cost be allocated based on the sum of scheduled energy and effective scheduled reserve of generators.

Comment received from David Bullen (EMC): *Reserve itself will not be scheduled such that it increases the risk to the system; energy will. Hence it is not right to charge for reserve "risk".*

Response: We have clarified that the inclusion of reserve in the reserve requirement is to prevent a generator from being scheduled reserve to cover its own generation risk and this does not increase the risk to the system.

Reserve is only scheduled on a risk-setter (generator with the greatest sum of scheduled energy and effective scheduled reserve): (i) to enable sufficient energy to be scheduled; or (ii) when the generator offers reserve at $0 (i.e. the MCE's Net Benefit calculation is unaffected by the scheduling of such reserve so the MCE is indifferent towards scheduling it).

<u>Example of case (i)</u>

Assume the modelled power system response = 0.

Here, reserve is scheduled from Generator A only because it allows sufficient reserve to be scheduled from the other Generators, which in turn allows sufficient energy to be scheduled.

Generator	Scheduled Energy	Effective scheduled reserve	Effective reserve required = Scheduled energy + Effective scheduled reserve
A	200	10	210
B	160	50	210
C	150	60	210
D	120	90	210
Total	630	210	

Suppose reserve were not scheduled from Generator A. Without increasing the effective reserve required, the sum of scheduled energy and effective scheduled reserve for each Generator would be limited to 200. This means that the total effective scheduled reserve given the scheduled energy of the Generators would be insufficient.

Generator	Scheduled Energy	Effective scheduled reserve	Effective reserve required = Scheduled energy + Effective scheduled reserve
A	200	0	200
B	160	40	200
C	150	50	200
D	120	80	200
Total	630	170 (insufficient)	

Limiting the total effective scheduled reserve to 170 would in turn limit the sum of scheduled energy and effective scheduled reserve for each Generator to 170. This means that the total scheduled energy given the effective scheduled reserve would be insufficient.

Generator	Scheduled Energy	Effective scheduled reserve	Effective reserve required = Scheduled energy + Effective scheduled reserve
A	170	0	170
B	130	40	170
C	120	50	170
D	90	80	170
Total	510 (Insufficient)	170	

Thus, it can be seen that reserve is only scheduled on Generator A to allow sufficient energy to be scheduled. Scheduled reserve itself is not a driver of the reserve requirement and generators should not be allocated reserve cost based on scheduled reserve.

The concept paper was then amended to include only scheduled energy in the suggested alternative basis for allocating reserve cost.

We also published the rule modification proposal on the EMC website for comments. No comments have been received for consideration.

9. Legal sign off

Text of rule modification (in Annex 4 and 5) has been vetted by EMC's legal counsel to reflect the intent of the rule modification proposal.

10. Recommendations

We recommend that the EMC Board:

a. **adopt** the EMC's rule modification proposal to amend the basis of allocating reserve cost to generators in Section A.2.1.1 of Appendix 7A of the Market Rules and other ancillary changes, as set out in the Annex 4 and 5;

b. **seek** the Authority's approval of the rule modification proposal; and

c. **recommend** that the rule modification proposal come into force two months after the date on which the approval of the Authority is published by the EMC.

Annex 1: Using IEQ as the basis for allocating reserve cost

For each dispatch period, each generator is allocated a fraction of the total reserve cost (RSC) given by its Reserve Responsibility Share (RRS).

The reserve cost allocated to a generator is then: RRS × RSC.

RRSs are calculated based on generators' IEQ as follows:

For SCU m

$$RRS = \begin{cases} 0, \text{ if } IEQ(m) \leq 0MWh \\ IEQ(m)/(PRQ+SRQ), \text{ otherwise} \end{cases}$$

For PCU z

$$RRS = \begin{cases} 0, \text{ if } IEQ(z) \leq 5MWh \\ PRQ/(PRQ+SRQ) \times SPF(z) \times \\ \sum_{j = z \text{ to } Z} \{[IEQ(j)-IEQ(j+1)]/(PRQ-5)\sum_{j = 1 \text{ to } z} SPF(j)\}, \text{ otherwise} \end{cases}$$

where:

PRQ	= IEQ of the PCU with the largest IEQ
SRQ	= sum of IEQs of all SCUs with positive IEQs
SPF(·)	= generator's standing probability of failure
IEQ(Z+1)	= 5MWh

$z \in \{1, 2, \ldots, Z\}$ is an index corresponding to an ordering of PCUs in descending IEQ.

Modified runway formula

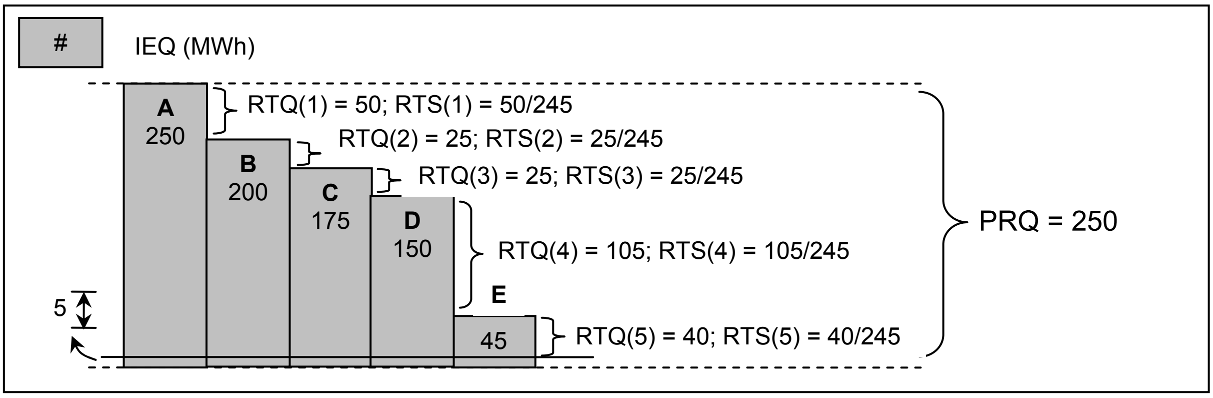
The reserve cost that is to be shared by PCUs [i.e. PRQ/(PRQ+SRQ)] is divided between PCUs with IEQ > 5MWh via the modified "runway" formula, which works as follows:

1. PCUs are ordered in descending IEQ and correspondingly indexed by $z \in \{1, 2, \ldots, Z\}$.
2. Reserve tiers and corresponding reserve tier quantities are defined such that the zth reserve tier quantity [RTQ(z)] is the difference between the IEQs of the zth and (z+1)th largest PCU, except the last reserve tier quantity [RTQ(Z)], which is the difference between the IEQ of the smallest PCU and 5MWh.
3. Reserve tiers are allocated shares of the total reserve cost to be split PCUs [i.e. PRQ/(PRQ+SRQ)] in proportion to their reserve tier quantities. These shares of total reserve cost are reserve tier shares [RTS(z)].
4. The zth reserve tier share is divided among the z largest PCUs in proportion to their SPFs.
5. Shares of reserve cost in each reserve tier allocated to a PCU are summed to give its RRS.

Example

For simplicity, assume there are no SCUs. Hence, SRQ = 0; PRQ/(PRQ+SRQ) = 1.

Suppose there are 5 PCUs (A to E) with IEQs and SPFs as shown below.



Their RRSs are determined as follows.

PCU	A	B	C	D	E
z	1	2	3	4	5
IEQ(z)	250	200	175	150	45
SPF(z)	0.01	0.02	0.03	0.01	0.02
RTQ(z) = IEQ(z)–IEQ(z+1)	50	25	25	105	40
RTS(z) = RTQ(z)/(250-5)	50/245	25/245	25/245	105/245	40/245
Share from RTS(1) = 50/245	0.20				
Share from RTS(2) = SPF(z) × 25/245 / (0.01+0.02)	0.03	0.07			
Share from RTS(3) = SPF(z) × 25/245 / (0.01+0.02+0.03)	0.02	0.03	0.05		
Share from RTS(4) = SPF(z) × 105/245 / (0.01+0.02+0.03+0.01)	0.06	0.12	0.18	0.06	
Share from RTS(5) = SPF(z) × 40/245 / (0.01+0.02+0.03+0.01+0.02)	0.02	0.04	0.05	0.02	0.04
RRS[8]	0.33	0.26	0.28	0.08	0.04

[8] RRSs do not sum to 1 due to rounding.

Annex 2: An alternative basis for allocating reserve cost

The reserve cost allocation using the alternative basis would be determined as follows:

For each dispatch period, each generator is allocated a fraction of the total reserve cost (RSC) given by its Reserve Responsibility Share (RRS).

The reserve cost allocated to a generator is: RRS × RSC.

<u>For SCU m</u>

$$RRS = \begin{cases} 0, \text{ if } SQ(m) \leq 0MW \\ SQ(m)/(PRQ+SRQ), \text{ otherwise} \end{cases}$$

<u>For PCU z</u>

$$RRS = \begin{cases} 0, \text{ if } SQ(z) \leq 10MW \\ PRQ/(PRQ+SRQ) \times SPF(z) \times \\ \sum_{j = z \text{ to } Z} \{[SQ(j)-SQ(j+1)]/(PRQ-10)\sum_{j = 1 \text{ to } z} SPF(j)\}, \text{ otherwise} \end{cases}$$

where:

SQ(·)	= generator's scheduled energy
PRQ	= SQ(·) of the PCU with the largest SQ(·)
SRQ	= sum of SQ(·) of all SCUs with positive SQ(·)
SPF(·)	= generator's standing probability of failure
SQ(Z+1)	= 10MW

$z \in \{1, 2, \ldots, Z\}$ is an index corresponding to an ordering of PCUs in descending SQ(·).

Note: The threshold for PCUs to bear reserve cost is changed from 5MWh to 10MW, which is the level of power that when supplied over a ½h dispatch period is equivalent to 5MWh of energy.

Annex 3: Cumulative reserve cost for July to September 2004

(Excludes 6 re-run periods)

Generator	Reserve cost using IEQ as the basis for allocation ($)	Reserve cost using the alternative basis for allocation ($)	Difference ($)
1	1,606,406	1,614,044	7,638
2	662,423	691,308	28,884
3	563,859	552,161	-11,698
4	537,032	515,254	-21,778
5	529,228	535,474	6,246
6	416,502	428,042	11,540
7	260,246	286,071	25,825
8	154,039	106,071	-47,968
9	106,372	96,940	-9,432
10	42,425	45,265	2,840
11	28,743	29,274	530
12	26,606	25,007	-1,599
13	23,332	24,536	1,204
14	18,916	19,616	700
15	14,547	14,845	298
16	14,011	15,287	1,276
17	7,938	10,656	2,717
18	4,967	5,409	442
19	4,679	4,397	-282
20	3,779	3,749	-30
21	2,917	3,097	180
22	2,474	2,691	217
23	2,323	3,556	1,233
24	1,110	1,145	36
25	1,010	1,075	65
26	956	1,829	873
27	597	636	39
28	57	55	-1
29	49	49	0
30	17	21	4
Total	5,037,560	5,037,560	0

ANNEX 4 : Proposed rule modifications

Existing rules (Release 1 April 2005)	**Proposed rules** (Deletions represented by strikethrough; additions by underline)	**Reason for Modification**
Appendix 7A		
A.2.1 In this Appendix: A.2.1.1 a reference to the "size" of a *GRF* in a *settlement interval* means the injected energy quantity, or IEQ, (in MWh) of that *GRF* in that *settlement interval*, and shall be designated by SZ;	A.2.1 In this Appendix: A.2.1.1 a reference to the "size" of a *GRF* in ~~a~~ the *settlement interval* corresponding to a *dispatch period* ~~means the injected energy quantity, or IEQ, (in MWh) of that *GRF* in that *settlement interval*, and~~ shall be designated by SZ~~;~~, where, subject to section 10.3.3 of Chapter 6: SZ = (½-hour) × *energy* scheduled (in MW) from the *real-time dispatch schedule* for that *GRF* in that *dispatch period*	To change the basis for allocating reserve cost from IEQ to scheduled energy. (The specification in Annex 2 allocates reserve cost based on scheduled energy (in MW) and the threshold for non-SCUs to be allocated reserve cost is 10MW. However, as it is the convention in settlement for quantities to be given in MWh, an equivalent specification with reserve cost allocated based on (½h) × scheduled energy (in MW) and a threshold of 5MWh is used here.)

ANNEX 5 : Ancillary rule modifications

Existing rules (Release 1 April 2005)	Proposed rules (Deletions represented by strikethrough; additions by underline)	Reason for Modification
Chapter 6		
10.3.3 Where the *EMC* has issued a price revision *advisory notice* pursuant to section 9.3.2B in respect of a *dispatch period* in circumstances where there is no useable *real-time dispatch schedule* for *reserve* or *regulation* available during that *dispatch period*, the *settlement* quantities described in sections 10.3.1 and 10.3.2 shall, if possible, be determined by re-running the *market clearing engine* for the *dispatch period* using all the input data that should have been supplied to the *market clearing engine* at the time the *real-time dispatch schedule* for that *dispatch period* would normally have been produced. Where it is not possible to so re-run the *market clearing engine*, the *EMC* shall determine the *settlement* quantities described in sections 10.3.1 and 10.3.2 based on the *dispatch instructions* for *reserve* and *regulation* issued by the *PSO* for the applicable *dispatch period*.	10.3.3 Where the *EMC* has issued a price revision *advisory notice* ~~pursuant to~~ under section 9.3.2B ~~in respect of~~ for a *dispatch period* ~~in circumstances where there is~~ with no useable *real-time dispatch schedule* for *energy*, *reserve* and ~~or~~ *regulation* ~~available during that *dispatch period*~~, the *EMC* shall determine, for ~~the~~ *settlement* purposes ~~quantities described~~: 10.3.3.1 the size of a *GRF* in section A.2.1.1 of Appendix 7A; 10.3.3.2 the quantity of *reserve* supplied from a *registered facility* in section~~s~~ 10.3.1; and 10.3.3.3 the quantity of *regulation* supplied from a *registered facility* in section 10.3.2~~,~~ ~~shall, if possible, be determined~~ by re-running the *market clearing engine* for the *dispatch period*. The *market clearing engine* shall be re-run using all the input data that should have been supplied to ~~the~~	To provide a basis for allocating reserve cost when there is no real-time dispatch schedule: reserve cost will be allocated based on the dispatch schedule produced by re-running the MCE, or the PSO's dispatch instruction for the dispatch period (in order of priority). This is in line with the existing provisions for paying registered facilities for reserve and regulation when there is no real-time dispatch schedule. Other changes are to improve readability.

Existing rules (Release 1 April 2005)	**Proposed rules** (Deletions represented by strikethrough; additions by underline)	**Reason for Modification**
	~~*market clearing engine*~~ ~~at the time~~ it when the *real-time dispatch schedule* for that *dispatch period* would normally have been produced. Where it is not possible to so re-run the *market clearing engine*, the *EMC* shall determine the ~~*settlement*~~ quantities ~~described~~ in sections 10.3.3.1 to 10.3.3.3 ~~10.3.1 and 10.3.2~~ based on the *PSO*'s *dispatch instructions* for energy, *reserve* and *regulation* ~~issued by the *PSO*~~ for ~~the applicable~~ that *dispatch period*.	
Chapter 7		
Explanatory Note: The total cost of regulation in each settlement interval is allocated on a $/MWh basis across all MWh of consumption plus the first CSZ MWh produced by each generating unit in that settlement interval. CSZ is the "critical size" or output level of a generating unit and is expected to be 5 MWh, the maximum output of a 10 MW unit in a half-hour settlement interval. Units with output less than CSZ do not pay a share of reserve costs under the "modified runway formula" used to allocate reserve costs to generators as defined in Appendix 7A. The treatment of both regulation and reserve assumes that each generating unit at a generating plant is a separate facility - separately	**Explanatory Note: The total cost of regulation in each settlement interval is allocated on a $/MWh basis across all MWh of consumption plus the first CSZ ~~MWh~~ produced by each generating unit in that settlement interval.** **CSZ is the "critical size~~" or output level of a generating unit~~ and is ~~expected to be~~ 5 MWh, the maximum output of a 10 MW unit in a half-hour settlement interval.** **Units that are not Secondary Contingency Units and are scheduled for ~~with output~~ less than ~~CSZ~~ 10 MW of energy do not pay a share of reserve costs under the "modified runway formula" used to**	NB: Explanatory notes are not part of the Market Rules (Section 7.4.1 of Chapter 1). The changes here are to align the content of the Explanatory Note to the changed basis for allocating reserve cost, to correct errors and to improve clarity.

Existing rules (Release 1 April 2005)	Proposed rules (Deletions represented by strikethrough; additions by underline)	Reason for Modification
metered and hence has its own MNN – a treatment that will give generators strong incentives to meter each unit separately.	**allocate reserve costs to generators as defined in Appendix 7A.** **~~The treatment of both regulation and reserve assumes that each generating unit at a generating plant is a separate facility - separately metered and hence has its own MNN – a treatment that will give generators strong incentives to meter each unit separately.~~**	
Appendix 7A		
A.2.1.3 "*cut-off size*" or *CSZ* (in MWh) means the size below which a *GRF* that is not a *secondary contingency unit* will not pay a share of the cost of *reserve* but will pay for *regulation*;	A.2.1.3 "*cut-off size*" or *CSZ* (in MWh) means the size below which a *GRF* that is not a *secondary contingency unit* will not pay a share of the cost of *reserve* but will pay for *regulation*. <u>CSZ is 5 MWh</u>;	To include the value of CSZ in the Market Rules. The value of CSZ is currently only given within explanatory notes of the Market Rules.
4.2.1.5 "*probability of failure*", in respect of a *GRF,* means the probability that that the *GRF* will, after being *dispatched* by the *PSO* for a *settlement interval*, cease operating, disconnect from the *transmission system*, or both in that *settlement interval* even if no other *GRF* fails.	A.2.1.5 "*probability of failure*", in respect of a *GRF,* means the probability that that ~~the~~ *GRF* will, after being *dispatched* by the *PSO* for a *settlement interval*, cease operating, disconnect from the *transmission system*, or both in that *settlement interval* even if no other *GRF* fails.	To correct a typographic error.

Existing rules (Release 1 April 2005)	**Proposed rules** (Deletions represented by strikethrough; additions by underline)	**Reason for Modification**
Explanatory Note: ... **All PCUs share the remaining reserve costs – which pays for enough reserve to cover the loss of the largest unit – according to a "modified runway" formula. The basic concept behind this formula is that no unit should pay for reserves that are necessary only to protect against loss of a unit larger than itself, but each unit should pay a share of the costs of each "tier" of the reserve requirement that is protecting against loss of units its size or smaller. The RRS for each PCU is determined as follows:** • **The first tier of the total reserve requirement (in MWh) is defined as the difference between the sizes of the largest and the second-largest PCUs. The largest PCU is allocated all of this first tier of reserves, on the grounds that this tier is necessary only because the largest unit is producing more than the second-largest unit.** • **The second tier of reserves is defined as the difference between the sizes of the second- and the third-largest units. The largest two units share the costs of this tier x, on the grounds that this tier of reserves is necessary only because these two units are larger than the third-largest unit. The sharing of costs is in proportion to failure probabilities on the grounds that a less reliable unit should pay more than a more**	**Explanatory Note: ...** **All PCUs share the remaining reserve costs – which pays for enough reserve to cover the loss of the largest unit – according to a "modified runway" formula. The basic concept behind this formula is that no unit should pay for reserves that are necessary only to protect against loss of a unit larger than itself, but each unit should pay a share of the costs of each "tier" of the reserve requirement that is protecting against loss of units its size or smaller.** **The RRS for each PCU is determined as follows:** • **The first tier of the total reserve requirement (in MWh) is defined as the difference between the sizes of the largest and the second-largest PCUs. The largest PCU is allocated all of this first tier of reserves, on the grounds that this tier is necessary only because the largest unit is producing more than the second-largest unit.** • **The second tier of reserves is defined as the difference between the sizes of the second- and the third-largest units. The largest two units share the costs of this tier ~~x~~, on the grounds that this tier of reserves is necessary only because these two units are larger than the third-largest unit. The sharing of costs is in proportion to**	NB: Explanatory notes are not part of the Market Rules (Section 7.4.1 of Chapter 1). The changes here are to align the content of the Explanatory Note to the changed basis for allocating reserve cost, to correct errors and to improve clarity.

Existing rules (Release 1 April 2005)	Proposed rules (Deletions represented by strikethrough; additions by underline)	Reason for Modification
reliable unit. The "nth" tier of reserves is defined as the difference between the sizes of the nth- and the (n+1)th-largest unit. The first nth-largest units share the cost of this tier in proportion to their individual failure probabilities. This process is repeated until all PCUs with output greater than CSZ are allocated a share of the total costs reserves. The shares of all SCUs and all PCUs add up to 1.0. Units with output less than CSZ do not pay for operating reserves, but all units pay for regulation (at the same $/MWh charge paid by loads) in proportion to their output up to CSZ.	failure probabilities on the grounds that a less reliable unit should pay more than a more reliable unit. The "nth" tier of reserves is defined as the difference between the sizes of the nth- and the (n+1)th-largest unit. The first nth-largest units share the cost of this tier in proportion to their individual failure probabilities. This process is repeated until all PCUs ~~with output greater than CSZ~~ are allocated a share of the total cost~~s~~ <u>of</u> reserves. The shares of all SCUs and all PCUs add up to 1.0. Units <u>that are not SCUs and</u> with <u>size</u> ~~output~~ less than CSZ do not pay for operating reserves, but all units pay for regulation (at the same $/MWh charge paid by loads) in proportion to their <u>IEQ</u> ~~output~~ up to CSZ.	