Notice of Market Rules Modification

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Rule reference:	Chapter 6, Appendix 6D
Proposer:	Market Operations, EMC
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Category allocated:	2
Status:	Approved by EMA
Effective Date:	Implemented

Summary of proposed rule modification:

This proposal is to re-model Type 2 Artificial Lines in the Market Clearing Engine to ensure that nodal prices discovered at "disconnected" generation facilities reflect the locational system marginal price.

Date considered by Rules Change Panel:	3 July 2007
Date considered by EMC Board:	26 July 2007
Date considered by Energy Market Authority:	22 August 2007

Proposed rule modification:

See attached paper.

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

PAPER NO.	:	**EMC/BD/04/2007/04(b)**
RCP PAPER NO.	:	**EMC/RCP/33/2007/264**
SUBJECT	:	**RE-MODELING TYPE 2 ARTIFICIAL LINES**
FOR	:	**DECISION**
PREPARED BY	:	**POA TIONG SIAW** **SENIOR ECONOMIST**
REVIEWED BY	:	**PAUL POH LEE KONG** **SVP, MARKET ADMINISTRATION**
DATE OF MEETING	:	**26 JULY 2007**

Executive Summary

This paper assesses EMC's rule modification proposal to re-model Type 2 Artificial Lines in the MCE in order to correct for instances when nodal prices associated with "disconnected" generation units do not reflect the locational system marginal price. There could potentially be large settlement impact on such a unit if it is charged very high price (which does not reflect LSMP) for energy while it is on maintenance and drawing electricity for station load. This rule change was made as an urgent modification and took temporary effect on 9 Feb 2007. Under the Market Rules, it has to be submitted through the normal rule change process to be written permanently into the Market Rules. The RCP recommends that the EMC Board **adopt** this proposal.

1. Introduction

This paper assesses EMC's rule modification proposal to modify the Market Clearing Engine (MCE) to correct for instances when nodal prices associated with generation units (not represented as synchronized with the transmission system) do not reflect the locational system marginal price (LSMP).

There could potentially be large settlement impact on such a unit if it is charged very high price (which does not reflect LSMP) for energy while it is on maintenance and drawing electricity for station load. This rule change is an urgent modification to avoid unintended adverse effects from a provision of the market rules.

This rule change was an urgent modification:

- made by the Urgent Rule Modification Committee on 27 January 2007;
- confirmed by the EMC Board on 31 January 2007;
- approved by the EMA on 7 February 2007;
- effective on 9 February 2007; and
- valid till 8 February 2008 inclusive

The Market Rules provide that any urgent modification will apply for no longer than one year. As soon as reasonably practicable during the one-year period, the *EMC* shall submit the urgent modification to the rules change panel for its consideration as a modification proposal.

2. Background

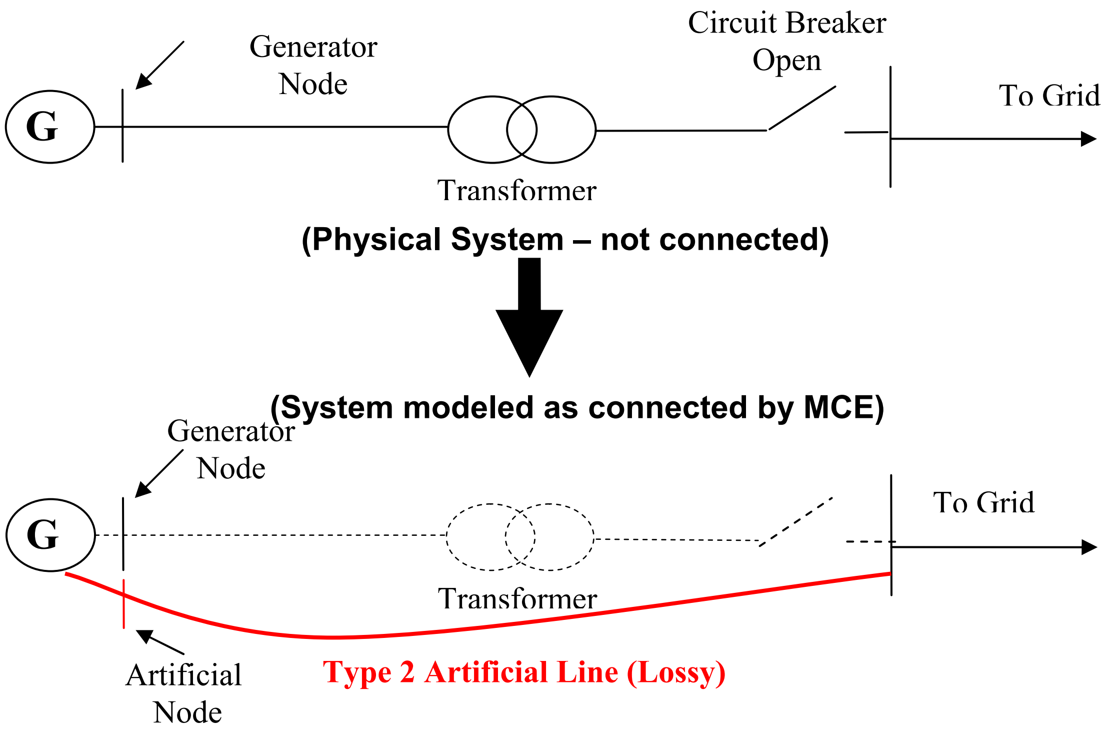
2.1 Locational System Marginal Price (LSMP)

The MCE is a marginal pricing model that establishes nodal prices that reflect the system marginal price. In the absence of transmission constraints (or congestion), all nodal prices reflect the system marginal price, i.e. each nodal price is the system marginal price adjusted for losses associated with that node. This is the LSMP. When congestion occurs, one system may effectively be broken into two or more isolated systems. There could then be different system marginal prices and the nodes within different systems will reflect their respective system marginal prices. This outcome is referred to as price separation.

In economic terms, each nodal price is the per MWh change in cost that has to be incurred by the system in order to meet incremental demand from that node.

2.2 Connectivity Modeling of Units that are "not connected"

For each period that any generating unit is "not represented as synchronised with the transmission system"[1] **(referred to in this paper as "not connected")**, it is nevertheless still modelled in the MCE as "connected". This is done so that it would be eligible for dispatch in the period. To do this, the MCE first creates an artificial node connecting to the generating unit, then connects the artificial node to the grid using "Type 2 Artificial Lines". This is depicted in the diagram below:



3. Analysis

3.1 Problem Definition

Many instances of nodal prices not reflecting their locational marginal system prices have been discovered at nodes associated with generation units that are "not connected". EMC's MCE consultants, PSC Consultants, have identified this result to be caused by inadequate MCE modeling of Type 2 Artificial Lines that are used to "connect" these generating units.

[1] The physical synchronization (or connection) of a unit is captured in the Network Status File (taken at T-10 minutes) that is used by the MCE for market clearing at T-5 minutes. If some units are ramping up and not able to synchronize by T-10 minutes, they would not be eligible for dispatch at T, even if they could have achieved synchronization before T. If so, restrictions owing to processing time would have denied physically eligible units from being dispatched in real time. Hence, modeling all units as "connected" is to allow such units to be eligible for dispatch at T.

3.1.1 Modeling of Transmission Lines

Under the Market Rules, the transmission flow-loss model used in the MCE is mathematically described as follows:

D.16.2 Line Flow

D.16.2.1 Flow Reverse Constraint:

$$\text{LineMaxReverse}_k \leq \text{LineFlow}_k + \text{ExcessLineFlowReverse}_k$$

$$\{k \in \text{LINES}, k \notin \text{ARTIFICIALLINES1} \cup \text{ARTIFICIALLINES3}\}$$

D.16.2.1 Flow Forward Constraint:

$$\text{LineMaxForward}_k \geq \text{LineFlow}_k - \text{ExcessLineFlowForward}_k$$

$$\{k \in \text{LINES}, k \notin \text{ARTIFICIALLINES3}\}$$

D.16.3 Line Losses

D.16.3.1 Line Flow Constraint:

$$\text{LineFlow}_k = \sum_{j \in \text{DISCRSUB}_k} \text{LineFlowConst}_{k,j} \times \text{Weight}_{k,j} + \text{DeficitWLineFlow}_k - \text{ExcessWLineFlow}_k$$

$$\{k \in \text{LINES}, k \notin \text{ARTIFICIALLINES1} \cup \text{ARTIFICIALLINES3}\}$$

D.16.3.2 Line Loss Constraint:

$$\text{LineLoss}_k = \sum_{j \in \text{DISCRSUB}_k} \text{LineLossConst}_{k,j} \times \text{Weight}_{k,j}$$

$$\{k \in \text{LINES}, k \notin \text{ARTIFICIALLINES1} \cup \text{ARTIFICIALLINES3}\}$$

D.16.3.3 Weight Summation Constraint:

$$\sum_{j \in \text{DISCRSUB}_k} \text{Weight}_{k,j} = 1$$

$$\{k \in \text{LINES}, k \notin \text{ARTIFICIALLINES1} \cup \text{ARTIFICIALLINES3}\}$$

3.1.2 Modeling of Type 2 Artificial Lines

For the purpose already described, Type 2 artificial lines are used to connect generating units that are "not connected". Compared to normal lines, the model for Type 2 Artificial Lines contains fewer line flow/line loss points. The line losses for Type 2 Artificial Lines are determined as follows:

D.9.5 $\text{LineFlowConst}_{k,1} = 0$

$\text{LineFlowConst}_{k,2} = \text{LineMaxForward}_{k}$

$\{ k \in \text{ARTIFICIALLINES2}\}$

D.9.6 $\text{LineLossConst}_{k,1} = 0$

$\text{LineLossConst}_{k,2} = (1 - \text{DefaultPriceConversionFactor}_{u(k)}) \times \text{LineFlowConst}_{k,2}$

$\{ k \in \text{ARTIFICIALLINES2}\}$

We observed from equations D.9.5 and D.9.6 that Type 2 Artificial Lines do not contain line flow/line loss points defined in the reverse direction. If there was a need to meet demand at the artificial node that the facility is connected to then it would not be able to be met from the system because there is no reverse flow loss tranche. Therefore, the higher-priced offer (that was not cleared) from the generating unit or a "deficit generator" violation would be required to meet the demand.

3.1.2 Consequences of Using existing Type 2 Artificial Lines

To consistently calculate the energy price at a generator node (see diagram in para 2.2) connected by a Type 2 Artificial Line, a reverse flow through the artificial line is required.

In general, the MCE would not be able to meet incremental demand at a node of a unit that is "not connected" with energy at LSMP under the following scenarios:

1. The unit has not offered any energy; and
2. The unit has offered energy but is not scheduled for energy.

The table below depicts the nodal pricing outcome that is (A) expected from the current MCE model and (B) correct from locational marginal pricing principle for an incremental demand:

Scenario	Energy Offered	(A) Expected Nodal Price	(B) Correct Nodal Price
1	0	VoLL	LSMP
2	Positive	Offer Price	LSMP

Under a locational marginal pricing regime, the price outcome in scenarios 1 and 2 should have been the Locational System Marginal Price or LSMP. Hence, the VoLL and Offer Price under both scenarios are not the intended correct nodal prices.

3.1.3 Occurrences of Nodal Prices not reflecting LSMP under Scenarios 1 & 2

Based on the current model, we would have expected VOLL and Offer Price to be established under Scenarios 1 and 2 respectively all along. However, these outcomes have not been observed previously. It is not clear why this is the case.

Annex 2 details recent incidents (9-16 November 2006) where some nodal prices did not reflect LSMP. These incidents have been recurring since. Note that some actual nodal pricing outcomes listed in Annex 2 were not expected results, i.e. VOLL under Scenario 1 or Offer Price under Scenario 2. It is not understood why the present MCE has produced the unexpected results.

4. Proposed Solution: Model Type 2 Artificial Lines using Characteristics of Real Lines

The purpose of an artificial line is to "connect" a generating unit to the overall system so that it has the opportunity to be scheduled if its offers can be cleared. The line is created in place of a real line that would be there if the unit was connected, but with different characteristics than a real line. These differences can cause situations resulting in MNN prices not reflecting their LSMPs. While it may be possible to modify the artificial lines further to eliminate these issues, the best solution instead would be to create artificial lines that more closely mimic real lines.

Hence, PSC Consultants' proposed solution is to:

1. PSO defines a default line, which would be an existing line, for each generating unit;
2. If a generating unit is not connected to the system, artificially connect it with a Type 2 Artificial Line that has the characteristics of the generating unit's default line.

This way, a full loss model with node angle constraints would be used for Type 2 Artificial Lines, which would also remove the need for the use of any price conversion factor. The main advantage of this approach is that the concept of artificial connection is retained while the characteristics of real lines are used.

For generating units where no default line can be designated by the PSO, it is proposed that EMC determine the electrical characteristics of the Type 2 Artificial Lines used to "connect" them. At present, only four NEA units belong to this category. NEA's generating units, which are connected at the relatively lower 22kV level, are modelled differently from regular generating units that are connected at 66kV and above levels.

4.1 Testing and Impact Analysis

A prototype MCE was developed by PSC Consultants and mappings for each generating unit to a real line were created. This prototype MCE was then re-run a number of times over the 4 days that the high prices occurred. Over 700 re-runs were performed and no nodal prices that do not reflect LSMP was observed for the disconnected generating units.

A full comparison of results for SNK CCP5 for all 48 trading periods on 11 Nov 2006 is displayed in **Annex 3**. These results showed the following:

1. Prices from the modified MCE runs reflected the respective LSMPs.
2. The absolute maximum deviation of prices produced by the modified MCE from the correct prices was $0.35.
3. The absolute maximum deviation of prices produced by the modified MCE from the correct prices as a percentage of the latter was 0.3%.

5. Comments from the Urgent Rule Modification Committee (URMC)[2]

The URMC convened on 24 January 2007 to consider this proposal. It made the rule modification and tasked EMC to undertake the following:

1. Monitor MCE results after its implementation;
2. Analyze MCE results spanning a period of 3 months and report findings and make a recommendation to the Rules Change Panel; and
3. Verify if the upgrading of the CPLEX solver in November 2006 is a possible cause of nodal prices not reflecting LSMPs.

6. Analysis of MCE results 12 Feb 2007 – 15 May 2007

MCE results for the periods between 12 Feb 2007 and 15 May 2007 were collected and analyzed. Each type of run (STS, RTS, PDS and MOS) was checked. In total, 145,413 periods and 5,994,243 MEP prices were checked**. (Summary results are provided in Annex 4).**

In conclusion, there was no occurrence of nodal prices not reflecting LSMPs that was caused by Type 2 Artificial Lines.

EMC's MCE consultants also confirmed that CPLEX upgrade had not been the cause of nodal prices not reflecting LSMPs. This was affirmed by running the MCE using the previous version of CPLEX and observing similar outcomes of nodal prices not reflecting LSMPs.

7. Conclusion

We conclude from the prototype simulation results and subsequent 3-month actual MCE results that the proposed solution rectifies the inadequate modeling of Type 2 Artificial Lines and enable nodal prices associated with "disconnected" units to reflect their locational system marginal prices.

[2] Under Section 5.10.1 of Chapter 3 of the Market Rules, the urgent rule modification committee is made up of the Chair of the Rules Change Panel, a representative of the PSO and one director of the EMC.

8. Consultation

We have published the rule modification proposal on the EMC website for comments. The following comments were received:

From PowerSeraya

"We accept the proposal as it formalises a change already in place within the MCE that prevents artificially high prices occurring when a generation facility is not connected to the transmission system."

9. Legal sign off

EMC's legal counsel has indicated that because of the technical nature of the rule modification proposal he is not able to provide a legal signoff.

10. Technical Working Group Discussion

The Technical Working Group (TWG) convened on 18 June 2007 to consider this proposal. The TWG noted the test results referred to in sections 4 and 6 of this paper. Given the positive outcome of the test results, the TWG unanimously endorsed the proposal.

11. Recommendations

The RCP unanimously recommends that the EMC Board:

a. **adopt** the rule modification to Appendix 6D, Chapter 6 of the Market Rules as set out in Annex 1 of this paper; and

b. **seek the Authority's approval for** the proposed rule modifications.

ANNEX 1: Proposed Rule Modification

Existing Rules (Release 1 Jan 2007)	**Proposed Rules** (Deletions represented by strikethrough text and addition double underlined.)	**Reason for Change**
Appendix D, Chapter 6 **D.3 Parameters** DefaultPriceConversionFactor$_u$ The default price conversion factor that is used to account for losses between a *generation unit* and its default bus. Determined by the *EMC* in accordance with section D.7.2 or D.7.3. PriceConversionFactor$_m$ The factor determined in accordance with section D.7 which is used to account for losses between the *generation facility* and the *market network node*, where this is appropriate. The default values are set by the *EMC* in accordance with section D.7.2 and D.7.3.	**Appendix D, Chapter 6** **D.3 Parameters** ~~DefaultPriceConversionFactor$_u$~~ ~~The default price conversion factor that is used to account for losses between a *generation unit* and its default bus. Determined by the *EMC* in accordance with section D.7.2 or D.7.3.~~ ~~PriceConversionFactor$_m$~~ ~~The factor determined in accordance with section D.7 which is used to account for losses between the *generation facility* and the *market network node*, where this is appropriate. The default values are set by the *EMC* in accordance with section D.7.2 and D.7.3.~~	Price Conversion factors are no longer required.
D.6.5 In the case where the *dispatch period* is involved in the calculation of a *short-term schedule, pre-dispatch schedule scenario* or *market outlook scenario*, or where the *dispatch period* is involved in the calculation of a *real-time dispatch schedule*, then the *EMC* shall make the following changes to the dispatch network for the *dispatch period* in respect of each *generation unit* for each *generation registered facility* which is not represented as *synchronised* in the status data on the network elements received from the *PSO*: D.6.5.1 Add an artificial *dispatch network node* and connect the *generation unit* to the *dispatch network node*. D.6.5.2 Add an artificial *dispatch network line* connected to the *artificial dispatch network node* described in D.6.5.1, and the default bus for the *generating unit* described in section D.7.2 or D.7.3, as the case may be. The artificial *dispatch network lines* used for this purpose shall not include constraints in sections D.16.2.3 and D.21.1, and shall have a conventional direction defined to be from the artificial *dispatch network node* to the default bus, and shall use a negative value specified by *EMC* for the parameter LineMaxReverse$_k$, and a value determined by the *EMC* for all such artificial *dispatch*	D.6.5 In the case where the *dispatch period* is involved in the calculation of a *real-time dispatch schedule*, *short-term schedule, pre-dispatch schedule scenario* or *market outlook scenario*, ~~or where the *dispatch period* is involved in the calculation of a *real-time dispatch schedule*,~~ then the *EMC* shall make the following changes to the dispatch network for the *dispatch period* in respect of each *generation unit* for each *generation registered facility* which is not represented as *synchronised* in the status data on the network elements received from the *PSO*: D.6.5.1 Add an artificial *dispatch network node* and connect the *generation unit* to the *dispatch network node*. D.6.5.2 Add an artificial *dispatch network line* connected to the *artificial dispatch network node* described in D.6.5.1, and the default bus for the *generating unit* described in section D.7.2 or D.7.3, as the case may be. An~~The~~ artificial *dispatch network line*~~*s*~~ used for this purpose shall not include the constraints in sections~~ D.16.2.3~~ ~~and~~ D.21.1, ~~and shall have a conventional direction defined to be from the artificial *dispatch network node* to the default bus, and shall use a negative value specified by *EMC* for the parameter LineMaxReverse$_k$, and a value determined by the *EMC* for all such artificial *dispatch network lines* as LineMaxForward$_k$.~~ and shall:	Drafting change Constraint D.16.2.3 now applies to this type of artificial line. Define the electrical

network lines as LineMax$Forward_k$. **Explanatory Note: The effect of this section is that in the preparation of real-time dispatch schedule, short-term schedule, pre-dispatch schedule and market outlook scenarios, the MCE will model all units as if they are connected, and hence the offers for the period will determine whether they generate in the schedule. The allowance for a very small reverse capability on the artifical dispatch network lines is to allow a shadow price to be derived at the artificial dispatch network node which is based on the local system marginal price.**	a. have the same electrical characteristics as the corresponding default line that is designated by *PSO* in section D.7.2A or D.7.3A, as the case may be; or b. have electrical characteristics determined by the *EMC* if no corresponding default line is designated by *PSO*. **Explanatory Note: The effect of this section is that in the preparation of real-time dispatch schedule, short-term schedule, pre-dispatch schedule and market outlook scenarios, the MCE will model all units as if they are connected, and hence the offers for the period will determine whether they generate in the schedule. ~~The allowance for a very small reverse capability on the artifical dispatch network lines is to allow a shadow price to be derived at the artificial dispatch network node which is based on the local system marginal price.~~**	characteristics of this type of artificial line.
D.7.2 The *PSO* shall designate a main default bus, and an alternate default bus which is in the same substation/switchouse as the main default bus, for each *generation registered facility* that is not a *multi-unit facility* and each *generation settlement facility*, representing the most likely connection point for that *generation facility*. The *EMC* shall specify on reasonable grounds for each *generation registered facility* that is not a *multi-unit facility* and each *generation settlement facility* a default price conversion factor based on the historical observed price ratio between the normal connection point of the *generation facility* and the designated main default bus for that *generation facility*.	D.7.2 The *PSO* shall designate a main default bus, and an alternate default bus which is in the same substation/switchouse as the main default bus, for each *generation registered facility* that is not a *multi-unit facility* and each *generation settlement facility*, representing the most likely connection point for that *generation facility*. ~~The *EMC* shall specify on reasonable grounds for each *generation registered facility* that is not a *multi-unit facility* and each *generation settlement facility* a default price conversion factor based on the historical observed price ratio between the normal connection point of the *generation facility* and the designated main default bus for that *generation facility*.~~	Price Conversion factors are no longer required.
	New Section D.7.2A The *PSO* shall, wherever possible, designate a default line for each *generation registered facility* that is not a *multi-unit facility* and each *generation settlement facility*, representing the most likely connection line for that *generation facility*.	PSO to designate default line wherever possible

D.7.3 The *PSO* shall designate a main default bus, and an alternate default bus which is in the same substation/switchouse as the main default bus, for each *generation* unit of each *generation registered facility* that is a *multi-unit facility*, representing the most likely connection point for that *generation* unit. The *EMC* shall specify on reasonable grounds for each *generation* unit of each *generation registered facility* that is a *multi-unit facility* a default price conversion factor based on the historical observed price ratio between the normal connection point of the *generation* unit and the designated main default bus for that *generation unit*, together with a proportion indicating the ratio by which the prices of the nodes corresponding to the designated main default buses will be combined into the *market network node* energy price.	D.7.3 The *PSO* shall designate a main default bus, and an alternate default bus which is in the same substation/switchouse as the main default bus, for each *generation* unit of each *generation registered facility* that is a *multi-unit facility*, representing the most likely connection point for that *generation* unit. The *EMC* shall specify on reasonable grounds~~ for each *generation* unit of each *generation registered facility* that is a *multi-unit facility* a default price conversion factor based on the historical observed price ratio between the normal connection point of the *generation* unit and the designated main default bus for that *generation unit*, together with~~ a proportion indicating the ratio by which the prices of the nodes corresponding to the designated main default buses will be combined into the *market network node* energy price~~.~~	Price Conversion factors are no longer required.
	New Section D.7.3B The *PSO* shall, wherever possible, designate a default line for each *generation* unit of each *generation registered facility* that is a *multi-unit facility*, representing the most likely connection line for that *generation* unit.	PSO to designate default line where possible

D.7.4 If a *generation registered facility* is not a *multi-unit facility* and is either represented as *synchronised* in the *dispatch network data*, or is deemed to be connected to the dispatch network in accordance in section D.6.5, then the *dispatch network node* representing the point of connection in the *dispatch network data* shall be designated the *market network node* for that *generation facility* and the price conversion factor for the *market network node* in this case shall be 1.	D.7.4 If a *generation registered facility* is not a *multi-unit facility* and is either represented as *synchronised* in the *dispatch network data*, or is deemed to be connected to the dispatch network in accordance in section D.6.5, then the *dispatch network node* representing the point of connection in the *dispatch network data* shall be designated the *market network node* for that *generation facility* ~~and the price conversion factor for the *market network node* in this case shall be 1~~.	Price Conversion factors are no longer required.
D.7.6 If a *generation registered facility* is a *multi-unit facility* and is either represented as *synchronised* in the *dispatch network data* or is deemed to be connected to the dispatch network in accordance with section D.6.5, then the *dispatch network node* added to the dispatch network in accordance with section D.8.2 shall be designated the *market network node* for that *generation facility*, and the price conversion factor for the *market network node* in this case shall be 1.	D.7.6 If a *generation registered facility* is a *multi-unit facility* and is either represented as *synchronised* in the *dispatch network data* or is deemed to be connected to the dispatch network in accordance with section D.6.5, then the *dispatch network node* added to the dispatch network in accordance with section D.8.2 shall be designated the *market network node* for that *generation facility*~~, and the price conversion factor for the *market network node* in this case shall be 1~~.	Price Conversion factors are no longer required.
D.7.8 The *market network node* for a *generation settlement facility* shall be the *dispatch network node* corresponding to the bus designated by the *PSO* as being the default connection bus for that *generation facility*, and the price conversion factor for the *market network node* in this case shall be the value supplied by the *EMC* in accordance with section D.7.2.	D.7.8 The *market network node* for a *generation settlement facility* shall be the *dispatch network node* corresponding to the bus designated by the *PSO* as being the default connection bus for that *generation facility*~~, and the price conversion factor for the *market network node* in this case shall be the value supplied by the *EMC* in accordance with section D.7.2~~.	Price Conversion factors are no longer required.
D.9.1 $\text{LineAdmittance}_k = -\frac{\text{Reactance}_k}{\text{Resistance}_k^2 + \text{Reactance}_k^2}$ $\{k \in \text{LINES},\ k \notin \text{ARTIFICAILLINES}\}$	D.9.1 $\text{LineAdmittance}_k = -\frac{\text{Reactance}_k}{\text{Resistance}_k^2 + \text{Reactance}_k^2}$ ~~$\{k \in \text{LINES},\ k \notin \text{ARTIFICAILLINES}\}$~~ $\underline{\{k \in \text{LINES}, k \notin \text{ARTIFICIALLINES1} \cup \text{ARTIFICIALLINES3}\}}$	Include this constraint for Type 2 Artificial line
D.9.2 The *EMC* shall determine NumPoints_k, the number of line flow/line loss points required in the set DISCRSUB_k in order to define the linear approximation of the quadratic loss curve for each *dispatch network line k*, except for the artificial *dispatch network lines* added under sections D.6.5 or D.8.2.	D.9.2 The *EMC* shall determine NumPoints_k, the number of line flow/line loss points required in the set DISCRSUB_k in order to define the linear approximation of the quadratic loss curve for each *dispatch network line k*, except for the artificial *dispatch network lines* added under sections ~~D.6.5~~ D.6.3.4 or D.8.2.	Only Type 2 Artificial lines require NumPoints to be determined.

D.9.3 $\text{MaxLineRating}_k = \text{maximum}(\text{LineRatingForward}_k, \text{LineRatingReverse}_k)$ $\text{LineFlowConst}_{k,j} = -\text{MaxLineRating}_k + \frac{j-1}{\text{NumPoints}_k - 1} \times \text{MaxLineRating}_k \times 2$ $\{k,j \mid j \in \{1,\ldots,\text{NumPoints}_k\}, \text{where } k \in \text{LINES}, k \notin \text{ARTIFICAILLINES}\}$ D.9.4 $\text{LineLossConst}_{k,j} = \text{FixedLosses}_k + \text{Resistance}_k \times \text{LineFlowConst}_{k,j}^2$ $\{k,j \mid j \in \{1,\ldots,\text{NumPoints}_k\}, \text{where } k \in \text{LINES}, k \notin \text{ARTIFICIALLINES}\}$	D.9.3 $\text{MaxLineRating}_k = \text{maximum}(\text{LineRatingForward}_k, \text{LineRatingReverse}_k)$ $\text{LineFlowConst}_{k,j} = -\text{MaxLineRating}_k + \frac{j-1}{\text{NumPoints}_k - 1} \times \text{MaxLineRating}_k \times 2$ $\cancel{\{k,j \mid j \in \{1,\ldots,\text{NumPoints}_k\}, \text{where } k \in \text{LINES}, k \notin \text{ARTIFICAILLINES}\}}$ $\underline{\{k,j \mid j \in \{1,\ldots,\text{NumPoints}_k\}, \text{where } k \in \text{LINES}, k \notin \text{ARTIFICIALLINES1} \cup \text{ARTIFICIALLINES3}\}}$ D.9.4 $\text{LineLossConst}_{k,j} = \text{FixedLosses}_k + \text{Resistance}_k \times \text{LineFlowConst}_{k,j}^2$ $\cancel{\{k,j \mid j \in \{1,\ldots,\text{NumPoints}_k\}, \text{where } k \in \text{LINES}, k \notin \text{ARTIFICIALLINES}\}}$ $\underline{\{k,j \mid j \in \{1,\ldots,\text{NumPoints}_k\}, \text{where } k \in \text{LINES}, k \notin \text{ARTIFICIALLINES1} \cup \text{ARTIFICIALLINES3}\}}$	Include these constraints for Type 2 Artificial line
D.9.5 $\text{LineFlowConst}_{k,1} = 0$ $\text{LineFlowConst}_{k,2} = \text{LineMaxForward}_k$ $\{k \in \text{ARTIFICIALLINES2}\}$	~~D.9.5~~ $\cancel{\text{LineFlowConst}_{k,1} = 0}$ $\cancel{\text{LineFlowConst}_{k,2} = \text{LineMaxForward}_k}$ $\cancel{\{k \in \text{ARTIFICIALLINES2}\}}$	No longer required.
D.9.6 $\text{LineLossConst}_{k,1} = 0$ $\text{LineLossConst}_{k,2} = (1 - \text{DefaultPriceConversionFactor}_{u(k)}) \times \text{LineFlowConst}_{k,2}$ $\{k \in \text{ARTIFICIALLINES2}\}$	~~D.9.6~~ $\cancel{\text{LineLossConst}_{k,1} = 0}$ $\cancel{\text{LineLossConst}_{k,2} = (1 - \text{DefaultPriceConversionFactor}_{u(k)}) \times \text{LineFlowConst}_{k,2}}$ $\cancel{\{k \in \text{ARTIFICIALLINES2}\}}$	No longer required.
D.16.2.3 Node Angle Constraint	D.16.2.3 Node Angle Constraint	Include this constraint for Type 2 Artificial line

$\text{LineFlow}_k = \text{LineAdmittance}_k \times (\text{NodeAngle}_{NodeAtStartOf(k)} - \text{NodeAngle}_{NodeAtEndOf(k)} + \text{PhaseAngleShift}_k)$ $\{k \in \text{LINES}, k \notin \text{ARTIFICIALLINES}\}$ However, in the case where the constraint in this section D.16.2.3 corresponds to a notional line connecting two electrically equivalent buses introduced to the dispatch network in accordance with section D.6.3.4, then the following constraint shall be substituted: $0 = (\text{NodeAngle}_{NodeAtStartOf(k)} - \text{NodeAngle}_{NodeAtEndOf(k)})$ $\{k \in \text{ARTIFICIALLINES3}\}$	$\text{LineFlow}_k = \text{LineAdmittance}_k \times (\text{NodeAngle}_{NodeAtStartOf(k)} - \text{NodeAngle}_{NodeAtEndOf(k)} + \text{PhaseAngleShift}_k)$ $\cancel{\{k \in \text{LINES}, k \notin \text{ARTIFICIALLINES}\}}$ $\underline{\{k \in \text{LINES}, k \notin \text{ARTIFICIALLINES1} \cup \text{ARTIFIALLNES3}\}}$ However, in the case where the constraint in this section D.16.2.3 corresponds to a notional line connecting two electrically equivalent buses introduced to the dispatch network in accordance with section D.6.3.4, then the following constraint shall be substituted: $0 = (\text{NodeAngle}_{NodeAtStartOf(k)} - \text{NodeAngle}_{NodeAtEndOf(k)})$ $\{k \in \text{ARTIFICIALLINES3}\}$	
D.24.1.1 For *generation registered facilities* that are not multi-unit facilities, for *generation settlement facilities*, and for *generation registered facilities* that are *multi-unit facilities* represented as being *synchronised* or connected to the *dispatch network* in accordance with section D.6.5 in the *dispatch period*, the *market energy price* shall be calculated as follows: $\text{MEP}^{m(g)} = \text{EnergyPrice}_{n(m)} \times \text{PriceConversionFactor}_m$ where: $\text{EnergyPrice}_{n(m)}$ is the dual variable corresponding to constraint D.16.1.2 for the *dispatch network node n* corresponding to the *market network node m*; and $\text{PriceConversionFactor}_m$ is the relevant price conversion factor described in section D.7 for the *generation facility*.	D.24.1.1 For *generation registered facilities* that are not multi-unit facilities, for *generation settlement facilities*~~, and for *generation registered facilities* that are *multi-unit facilities*~~ represented as ~~being~~ *synchronised* or connected to the *dispatch network* in accordance with section D.6.5 in the *dispatch period*, the *market energy price* shall be calculated as follows: $\text{MEP}^{m(g)} = \text{EnergyPrice}_{n(m)} \cancel{\times \text{PriceConversionFactor}_m}$ where: $\text{EnergyPrice}_{n(m)}$ is the dual variable corresponding to constraint D.16.1.2 for the *dispatch network node n* corresponding to the *market network node m*~~; and~~ ~~PriceConversionFactor*m* is the relevant price~~ ~~conversion factor described in section D.7 for the *generation facility*.~~	Price Conversion factors are no longer required. The MEP for generation registered facilities that are multi-unit facilities should be determined according to D.24.1.2.

<table>
<tr>
<td>The price MEPm shall then be further modified in accordance with section D.24.5.</td>
<td>The price MEPm shall then be further modified in accordance with section D.24.5.</td>
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D.24.1.2 For generation registered facilities that are multi-unit facilities represented as not being synchronised and which are not connected to the dispatch network in accordance with section D.6.5 in the dispatch period, the market energy prices shall be calculated as follows:

$$MEP^{m(g)} = \frac{\sum_{u \in UNITS_g} \begin{pmatrix} Proportion_u \times EnergyPrice_{n(u)} \\ \times DefaultPriceConversionFactor_u \end{pmatrix}}{\sum_{u \in UNITS_g} Proportion_u}$$

where:

$UNITS_g$ is the set of all constituent generation units that form part of the generation registered facility associated with energy offer g ∈ MULTIOFFERS;

$Proportion_u$ is the relevant proportion specified by the EMC in accordance with section D.7.3;

$EnergyPrice_{n(u)}$ is the dual variable corresponding to constraint D.16.1.2 for the dispatch network node n; and

$DefaultPriceConversionFactor_u$ is the relevant price conversion factor described in section D.7.3.

The price MEP^m shall then be further modified in accordance with section D.24.5.
</td>
<td>
D.24.1.2 For generation registered facilities that are multi-unit facilities represented as ~~not~~ being synchronised ~~and which are not~~ <u>or</u> connected to the dispatch network in accordance with section D.6.5 in the dispatch period, the market energy prices shall be calculated as follows:

$$\cancel{MEP^{m(g)} = \frac{\sum_{u \in UNITS_g} \begin{pmatrix} Proportion_u \times EnergyPrice_{n(u)} \\ \times DefaultPriceConversionFactor_u \end{pmatrix}}{\sum_{u \in UNITS_g} Proportion_u}}$$

$$\underline{MEP^{m(g)} = \frac{\sum_{u \in UNITS_g} \left(Proportion_u \times EnergyPrice_{n(u)}\right)}{\sum_{u \in UNITS_g} Proportion_u}}$$

where:

$UNITS_g$ is the set of all constituent generation units that form part of the generation registered facility associated with energy offer g ∈ MULTIOFFERS;

$Proportion_u$ is the relevant proportion specified by the EMC in accordance with section D.7.3;

$EnergyPrice_{n(u)}$ is the dual variable corresponding to constraint D.16.1.2 for the dispatch network node n; and

~~DefaultPriceConversionFactor_u is the relevant price conversion factor described in section D.7.3.~~

The price MEP^m shall then be further modified in accordance with section D.24.5.
</td>
<td>Price Conversion factors are no longer required.</td>
</tr>
</table>

ANNEX 2: INSTANCES OF ERRONEOUS NODAL PRICES (Expected and unexpected Results)

Date	Period	Unit	Actual Nodal Price	Expected Result?	Correct Nodal Price (LSMP)	Schedule	Offer Price (1st price-quantity pair)
9-Nov-06	28	POWSNKO : CCP S1 : SNKCCP2	$4,500.00	Y	$133.31	0	$0.00
9-Nov-06	29	POWSNKO : CCP S1 : SNKCCP2	$4,500.00	Y	$125.37	0	$0.00
9-Nov-06	31	POWSNKO : CCP S1 : SNKCCP2	$4,500.00	Y	$126.97	0	$0.00
9-Nov-06	33	POWSNKO : CCP S1 : SNKCCP2	$4,500.00	Y	$124.85	0	$0.00
10-Nov-06	34	POWSERY : JPS.II : JUR GT2	$700.02	Y	$123.52	0	$700.00
10-Nov-06	46	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$105.94	0	$0.00
10-Nov-06	47	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$102.12	0	$0.00
10-Nov-06	48	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$100.17	0	$0.00
11-Nov-06	1	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$97.94	0	$0.00
11-Nov-06	2	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$95.18	0	$0.00
11-Nov-06	3	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$98.01	0	$0.00
11-Nov-06	4	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$102.34	0	$0.00
11-Nov-06	6	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$95.25	0	$0.00
11-Nov-06	7	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$93.07	0	$0.00
11-Nov-06	9	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$93.00	0	$0.00
11-Nov-06	10	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$93.00	0	$0.00
11-Nov-06	12	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$92.95	0	$0.00
11-Nov-06	13	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$93.06	0	$0.00
11-Nov-06	15	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$96.88	0	$0.00
11-Nov-06	16	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$110.41	0	$0.00
11-Nov-06	17	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$102.52	0	$0.00
11-Nov-06	18	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$112.63	0	$0.00
11-Nov-06	19	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$117.00	0	$0.00
11-Nov-06	20	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$124.00	0	$0.00

Date	Period	Unit	Actual Nodal Price	Expected Result?	Correct Nodal Price (LSMP)	Schedule	Offer Price (1st price-quantity pair)
11-Nov-06	22	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$126.98	0	$0.00
11-Nov-06	23	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$126.90	0	$0.00
11-Nov-06	24	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$125.90	0	$0.00
11-Nov-06	32	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$112.27	0	$4,500.00
11-Nov-06	39	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$112.98	0	$4,500.00
11-Nov-06	44	POWSNKO : CCP S3 : SNKCCP5	$837.84	**N**	$102.50	0	$4,500.00
12-Nov-06	1	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$100.27	0	$0.00
12-Nov-06	2	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$100.27	0	$0.00
12-Nov-06	3	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$100.36	0	$0.00
12-Nov-06	4	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$100.33	0	$0.00
12-Nov-06	5	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$99.99	0	$0.00
12-Nov-06	6	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$99.97	0	$0.00
12-Nov-06	7	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$96.98	0	$0.00
12-Nov-06	10	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$96.39	0	$0.00
12-Nov-06	11	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$96.59	0	$0.00
12-Nov-06	12	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$96.88	0	$0.00
12-Nov-06	13	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$99.96	0	$0.00
12-Nov-06	14	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$99.97	0	$0.00
12-Nov-06	15	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$99.97	0	$0.00
12-Nov-06	16	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$100.37	0	$0.00
12-Nov-06	17	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$110.36	0	$0.00
12-Nov-06	18	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$115.48	0	$0.00
12-Nov-06	19	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$115.32	0	$0.00
12-Nov-06	20	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$117.32	0	$0.00
12-Nov-06	21	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$120.36	0	$0.00
12-Nov-06	23	POWSNKO : CCP S3 : SNKCCP5	$130.68	**N**	$115.47	0	$4,500.00

Date	Period	Unit	Actual Nodal Price	Expected Result?	Correct Nodal Price (LSMP)	Schedule	Offer Price (1st price-quantity pair)
12-Nov-06	24	POWSNKO : CCP S3 : SNKCCP5	$130.39	**N**	$115.21	0	$4,500.00
12-Nov-06	25	POWSNKO : CCP S3 : SNKCCP5	$128.97	**N**	$113.96	0	$4,500.00
12-Nov-06	27	POWSNKO : CCP S3 : SNKCCP5	$701.00	**N**	$112.69	0	$4,500.00
12-Nov-06	29	POWSNKO : CCP S3 : SNKCCP5	$127.54	**N**	$112.69	0	$4,500.00
12-Nov-06	33	POWSNKO : CCP S3 : SNKCCP5	$132.52	**N**	$113.61	0	$4,500.00
12-Nov-06	36	POWSNKO : CCP S3 : SNKCCP5	$130.77	**N**	$115.54	0	$4,500.00
13-Nov-06	1	POWSNKO : CCP S3 : SNKCCP5	$916.17	**N**	$96.81	0	$4,500.00
13-Nov-06	7	POWSNKO : CCP S3 : SNKCCP5	$1,003.43	**N**	$90.95	0	$4,500.00
13-Nov-06	12	POWSNKO : CCP S3 : SNKCCP5	$827.04	**N**	$91.72	0	$4,500.00
13-Nov-06	13	POWSNKO : CCP S3 : SNKCCP5	$4,499.51	Y	$92.28	0	$4,500.00
13-Nov-06	15	POWSNKO : CCP S3 : SNKCCP5	$840.20	**N**	$104.86	0	$4,500.00
13-Nov-06	19	POWSNKO : CCP S3 : SNKCCP5	$163.68	**N**	$125.80	0	$4,500.00
13-Nov-06	24	POWSNKO : CCP S3 : SNKCCP5	$4,499.52	Y	$124.88	0	$4,500.00
13-Nov-06	25	POWSNKO : CCP S3 : SNKCCP5	$164.27	**N**	$126.39	0	$4,500.00
13-Nov-06	35	POWSNKO : CCP S3 : SNKCCP5	$161.03	**N**	$123.16	0	$4,500.00
13-Nov-06	40	POWSNKO : CCP S3 : SNKCCP5	$4,499.41	Y	$122.98	0	$4,500.00
14-Nov-06	1	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$100.25	0	$0.00
14-Nov-06	2	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$100.27	0	$0.00
14-Nov-06	3	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$100.27	0	$0.00
14-Nov-06	4	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$97.44	0	$0.00
14-Nov-06	5	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$97.43	0	$0.00
14-Nov-06	6	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$96.88	0	$0.00
14-Nov-06	7	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$92.66	0	$0.00
14-Nov-06	9	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$92.56	0	$0.00
14-Nov-06	10	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$92.64	0	$0.00
14-Nov-06	11	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$96.88	0	$0.00

Date	Period	Unit	Actual Nodal Price	Expected Result?	Correct Nodal Price (LSMP)	Schedule	Offer Price (1st price-quantity pair)
14-Nov-06	12	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$97.45	0	$0.00
14-Nov-06	13	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$102.45	0	$0.00
14-Nov-06	14	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$102.49	0	$0.00
14-Nov-06	15	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$102.83	0	$0.00
14-Nov-06	16	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$117.23	0	$0.00
14-Nov-06	19	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$126.80	0	$0.00
14-Nov-06	20	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$126.33	0	$0.00
14-Nov-06	21	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$129.31	0	$0.00
14-Nov-06	22	POWSNKO : CCP S3 : SNKCCP5	$705.11	**N**	$133.58	0	$4,499.99
14-Nov-06	25	POWSNKO : CCP S3 : SNKCCP5	$528.33	**N**	$130.31	0	$4,499.99
14-Nov-06	30	POWSNKO : CCP S3 : SNKCCP5	$4,499.95	Y	$130.31	0	$4,499.99
14-Nov-06	32	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$129.14	0	$0.00
14-Nov-06	35	POWSNKO : CCP S3 : SNKCCP5	$4,500.00	Y	$123.19	0	$0.00

Annex 3: Test Results for SNK CCP5 for 11-Nov-06

	MNN PRICES FOR SNK CCP5						
Run Date Period	**Modified MCE**			**Production**	**Production Rerun**	**Max Deviation*($)**	**Max Deviation %**
11-Nov-2006 P01	98.11	98.23	98.17	4500	97.94	0.29	0.3%
11-Nov-2006 P02	95.41	95.41	95.41	4500	95.18	0.23	0.2%
11-Nov-2006 P03	98.3	98.18		4500	98.01	0.29	0.3%
11-Nov-2006 P04	102.52	102.53		4500	102.34	0.19	0.2%
11-Nov-2006 P05	95.63	95.63	95.51	95.34		0.29	0.3%
11-Nov-2006 P06	95.42	95.42		4500	95.25	0.17	0.2%
11-Nov-2006 P07	93.35	93.23		4500	93.07	0.28	0.3%
11-Nov-2006 P08	93.22	93.17		93		0.22	0.2%
11-Nov-2006 P09	93.17	93.17	93.17	4500	93	0.17	0.2%
11-Nov-2006 P10	93.17	93.22	93.23	4500	93	0.23	0.2%
11-Nov-2006 P11	92.82	92.82	92.82	92.66		0.16	0.2%
11-Nov-2006 P12	93.11	93.16	93.16	4500	92.95	0.21	0.2%
11-Nov-2006 P13	93.22	93.34	93.34	4500	93.06	0.28	0.3%
11-Nov-2006 P14	95.36	95.36		95.19		0.17	0.2%
11-Nov-2006 P15	97.12	97.12	97.05	4500	96.88	0.24	0.2%
11-Nov-2006 P16	110.61	110.61	110.61	4500	110.41	0.2	0.2%
11-Nov-2006 P17	102.82	102.7		4500	102.52	0.3	0.3%
11-Nov-2006 P18	112.91	112.83	112.83	4500	112.63	0.28	0.2%
11-Nov-2006 P19	117.35	117.29	117.27	4500	117	0.35	0.3%
11-Nov-2006 P20	124.29	124.31		4500	124	0.31	0.3%
11-Nov-2006 P21	126.39	126.39	126.39	126.17		0.22	0.2%
11-Nov-2006 P22	127.2	127.27	127.27	4500	126.98	0.29	0.2%
11-Nov-2006 P23	127.22	127.22	127.22	4500	126.9	0.32	0.3%
11-Nov-2006 P24	126.13	126.13		4500	125.9	0.23	0.2%
11-Nov-2006 P25	124.39	124.31	124.33	124.02		0.37	0.3%
11-Nov-2006 P26	122.32	122.24	122.24	122.02		0.3	0.2%
11-Nov-2006 P27	117.29	117.29	117.23	117.02		0.27	0.2%
11-Nov-2006 P28	112.82	112.88	112.88	112.62		0.26	0.2%
11-Nov-2006 P29	111.3	111.22	111.36	111.03		0.33	0.3%
11-Nov-2006 P30	111.25	111.25	111.39	111.06		0.33	0.3%
11-Nov-2006 P31	112.53	112.61		112.28		0.33	0.3%
11-Nov-2006 P32	112.47	112.53		4500	112.27	0.26	0.2%
11-Nov-2006 P33	110.52	110.52		110.33		0.19	0.2%
11-Nov-2006 P34	110.34	110.34		110.07		0.27	0.2%
11-Nov-2006 P35	110.35	110.34		110.08		0.27	0.2%
11-Nov-2006 P36	103.38	103.45		103.15		0.3	0.3%
11-Nov-2006 P37	110.48	110.4	110.48	110.21		0.27	0.2%
11-Nov-2006 P38	112.47	112.53	112.47	112.27		0.26	0.2%
11-Nov-2006 P39	113.18	113.18	113.26	4500	112.98	0.28	0.2%
11-Nov-2006 P40	112.52			112.26		0.26	0.2%
11-Nov-2006 P41	111.3			111.11		0.19	0.2%
11-Nov-2006 P42	110.5			110.24		0.26	0.2%
11-Nov-2006 P43	110.27	110.4		110.07		0.33	0.3%
11-Nov-2006 P44	102.68	102.68		837.84	102.5	0.18	0.2%
11-Nov-2006 P45	102.62	102.62		102.37		0.25	0.2%
11-Nov-2006 P46	102.53	102.53		102.35		0.18	0.2%

11-Nov-2006 P47	98.16	98.28	97.99		0.29	0.3%
11-Nov-2006 P48	96.96	97.03	96.79		0.24	0.2%

*This is the maximum deviation value of the modified MCE solution from the “correct” price that is based on LSMP. These correct prices are from the production runs or production re-runs.

Annex 4: Summary of Actual MCE Results for 12 Feb – 15 May 2007

Abbreviations:

RTS: Real Time Schedule
STS: Short Term Schedule
PDS: Pre-dispatch Schedule
MOS: Market Outlook Scenarios

Occurrence of Abnormal High Nodal Prices at $4500

a) No case was observed in all the RTS, STS and MOS runs.

b) 5,980 (out of 2,398,969) such cases were observed in PDS runs, but which are not caused by Type 2 Artificial Lines but due to energy deficit.

Occurrence of Nodal Prices not reflecting LSMPs (sensitivity: 5% deviation between Nodal price and USEP)

a) 236 (out of 183,620) cases were observed in RTS runs, among which 24 cases were due to Type 1 Artificial Lines and 212 cases were due to line binding.

b) 1463 (out of 2,315,077) cases were observed in STS runs, among which 356 cases were due to Type 1 Artificial Lines and 1107 cases were due to line binding.

c) 4231 (out of 2,398,969) cases were observed in PDS runs, among which 326 cases were due to Type 1 Artificial Lines, 1843 cases were due to line binding, 2060 were due to energy deficit, and 2 were due to Intertie security limit.

d) 4826 (out of 1,096,577) cases were observed in MOS runs, among which 53 cases were due to Type 1 Artificial Lines, 4734 cases were due to line binding, and 39 were due to Intertie security limit.