Notice of market rule modification

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Rule reference:	Section 7.2.2, chapter 6; section B.3, Appendix 6B and section G.2.3, Appendix 6G
Proposer:	Henry Gan (EMC Pte Ltd)
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Summary of proposed rules change: The rule modification proposes a new methodology to improve the calculation of the load participation factors (LPF). At present, the methodology for the calculation of the LPFs is static, which is based on historical data that may be up to 3 months old. The proposal is to use the most recent data from network status file, which is dynamic and captures the changes in real time load distribution in the power system.

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Proposed Rule Modification:

Refer to attachment

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

PAPER NO.	:	**EMC/BD/02/2004/08(c)**
PAPER NO.	:	**EMC/RCP/02/2004/229**
SUBJECT	:	**DYNAMIC LOAD PARTICIPATION FACTORS**
FOR	:	**DECISION**
PREPARED BY	:	**SHASHANK SWAN**
VETTED FOR QUALITY BY	:	**CHIAO YEN-SHONG** **Chief Economist**
APPROVED BY	:	**PAUL POH LEE KONG** **General Manager, Market Administration**
DATE	:	**9th March 2003**

Executive Summary

This paper assesses the rule modification that proposes a new methodology to improve the calculation of the load participation factors (LPF). At present, the methodology for the calculation of the LPFs is static, which is based on historical data that may be up to 3 months old. The proposal is to use the most recent data from network status file, which is dynamic and captures the changes in real time load distribution in the power system. One key benefit of the change is to ensure that the LPFs would incorporate changes in connectivity status and load shifting so that the constraint violation penalty would not be invoked and the resulting prices take account of load shifting. Analysis done by EMC suggests that this will lead to a more efficient market outcome. The RCP recommends that the EMC Board **support** the proposal.

1. Introduction

This paper assesses the change in the methodology for determining load participation factors (LPFs). The LPFs are used to allocate the system- wide non-dispatchable load forecast provided by the PSO to the individual off-take nodes as the nodal load forecasts for each off-take node for the purpose of generating dispatch and pricing schedules (both forecast and real-time schedules).

2. Background

The nodal load forecast for a node and a dispatch period is the expected load consumption at that node for that dispatch period. The nodal load forecast is calculated by multiplying the LPFs of each node by the. forecast of non-dispatchable load for each period.

Hence, for nodal load forecast to be accurate, LPFs should be reflective of load consumption occurring at various nodes at various times. Therefore, the LPFs are node, dispatch period and day specific. Special days (e.g. Christmas) have their specific LPFs

Calculation of LPFs: The LPFs are calculated using the actual loads extracted from the network status file. The actual load is converted to LPF by dividing the individual bus load by the total non-dispatchable load. The total non-dispatchable load is the sum of load over all connected nodes drawing energy from the grid[1].

Thus, LPF for node A = Load at node A / Total non-dispatchable load

3. Economic Analysis

Currently, LPFs are updated quarterly and are calculated at the beginning of every quarter for all the 48 periods of each day of the week. To properly reflect the load pattern due to special day effects, each day is classified as normal day or special day (e.g. Christmas)
For example, LPF to be used for node B for any Monday period 22 (e.g. 5th Jan, 12thJan, 19^{t} etc…) in a quarter is calculated using the data from Monday 2-3 week before the beginning of that quarter. If there is a holiday on any Monday (e.g. Chinese New Year), then special 'holiday' set will be used.

Problem definition

The current method thus uses one set of LPF values for a node for all the runs (i.e. real time schedule, pre-dispatch schedule etc) in a quarter. Since the load varies from period to period, the static nature of LPFs does not take account of changes in load profile during the quarter and may result in forecast inaccuracies. This problem becomes more pronounced when connectivity changes from the time data used for calculating the LPFs was collected

For example, LPFs to be used for a quarter and calculated before the beginning of the quarter using 320 connected nodes, will be misleading when 330 nodes are actually connected in the corresponding period in that quarter. This leads to inefficient market outcome.

Further, the current methodology does not take account of load shifting that may result in violation penalties to be invoked causing price spikes. For example, over year 2003, the market has experienced price spikes due to static nature of LPFs. This is because the static nature of LPFs is not reflective of the changes in real time load distribution in the power system as a result

[1] The number of nodes connected changes every period. For example, if period 22 has 320 nodes connected, period 23 may have 310 nodes connected.

of load being shifted by PSO to other circuits. Annex 2 spells out details of 3rd June'03 incidence which involved PSO shifting the load to other circuits/lines due to outage of a transformer.

There was no load shedding[2]; but the USEP went up to about $ 350 / MWh while the MNN (for generators) prices were about $ 90 /MWh.

Proposed Method

A flow chart explaining two step process performed in the new methodology is attached in Annex 3 while the detailed methodology is in Annex 4.

- The first step in the new method is to collect & store the *load* value of all connected nodes every half-hour, for every day (instead of LPFs). This actual load data is extracted from the network status file, which is received from the PSO 10 min before the start of a period. This is considered to represent the load disposition for the given period.
- The second step then is to calculate LPFs for all the connected nodes for the upcoming period (s) using the *latest* stored loads for the similar period and similar day. This is explained further for the following two scenarios

  - The LPFs for the real time schedule (RTS) (and the first period of Short Term Schedule which is not published) will normally use load values that were received in network status file in the preceding period. For example, in a RTS run for period 22 on Monday, the LPF will be computed from the actual load at that node in period 21, as captured in the network status file in period 21(20 mins into period 21. This load value is almost real time value for period 22 and is the best load information for upcoming period 22). Further, this load value is stored as value for period 22 for that node.

  - Forecast schedules (such as PDS, MOS and other periods of STS) will normally use load values that were stored one week previously for similar days and periods (since there is no load data received for the future periods at the time of the run). Where the connectivity status of a particular node differs from that in the previous week, latest load values for that node with the same connectivity status will be obtained from earlier week(s) for similar days and periods. Following example explains this (TABLE 1)

TABLE 1 Solving for period 24, Tuesday 15th April for 2 nodes (node K & node Y)

Node	Day /Date /period	Connected?	Which load values to use?
K	Tuesday/ 15th April/ 24	Yes	Solving for this period in a forecast run
Y	Tuesday/ 15th April/ 24	Yes	Solving for this period in a forecast run
K	Tuesday/ 8th April/ 24	No	Cannot use (different connectivity)
Y	Tuesday/ 8th April/ 24	No	Cannot use (different connectivity)
K	Tuesday/ 1st April/ 24	Yes	Can use- this is the latest load stored
Y	Tuesday/ 1st April/ 24	No	Cannot use (different connectivity)
K	Tuesday/ 25th March/ 24	Yes	Cannot use- not the *latest* value

[2] Similar cases of load-shifting have been observed. For example, on 12th June, USEP shot up in one period to $ 353 /MWh while MNN (for generators) price was about $82/MWh. In another incident, on 31st July USEP was around $ 200 /MWh for 7 consecutive periods against the MNN (for generators) price of approximately $90 /MWh

Y	Tuesday/ 25th March/ 24	Yes	Can use- this is the latest load stored

Thus the load data used for creating LPFs for forecast runs on 15th April will be sourced from different weeks for nodes K & Y (1st April data for node K and 25th March data for node Y) Last week's (or weeks before) load data is used in calculating LPFs as using most recent available information is expected to improve market outcome[3].

In summary, the following 2 tables sum arises the differences in methodologies

TABLE 2: Difference in how data is used.

Run type	Period (s)	LPFs in current method	LPFs in proposed method	Change
RTS	one	LPFs of the same period of similar days are identical for the quarter .They are based on data collected before the quarter starts.	LPFs calculated from the data in network status file received 10mins *before* that dispatch period. Thus, every period has a new LPF.	From historical data (up to 3 months old) to most recent data (real time/ dynamic)
STS	13 periods	LPFs from the same period of similar days created at the beginning of that quarter[4].	The first period (current period) will use LPFs as in RTS. For remaining 12 periods, LPFs created from the latest stored actual load for the similar period and similar day (which is usually one week old data).	From historical data (up to 3 months old) to most recent data (usually one week old).
PDS/MOS	From min. 28 periods and up to 72 periods/ 240 periods	LPFs from the same period of similar days created at the beginning of that quarter.	LPFs created from the latest stored actual load for the similar periods and similar days (usually one week old data).	From historical data (up to 3 months old) to most recent data (usually one week old).

[3] In contrast, the current methodology uses LPFs created at the beginning of that quarter (and not at the time of the run)
[4] STS rules are expected to be implemented in March 2004.

TABLE 3: Differences when the data is collected for calculating LPFs

	Current method	Proposed method	Change
Data source	Network Status file	Network Status file	None
When is data collected?	The data used for calculating LPFs to be used to generate nodal load forecasts for a quarter is taken 2 to 3 weeks before the beginning of that quarter. Testing is carried out during that period to ensure adequacy of the data.	Data is collected 10 minutes before the upcoming period from the network status file, every half hour.	Most recent data is collected, eliminating the need to collect data 2-3 weeks before the start of the quarter.

Hence, the advantages of proposed method are;

- The new method will largely eliminate distorted prices resulting from the current methodology not reflecting load shifting in real time[5].
- Using most recent and relevant information in the proposed method will lead to efficient price discovery and greater market efficiency.

Accordingly, section 7.2.2 of Chapter 6 has been modified, combining the contents of section B.3.1 of Appendix 6B. This improves clarity in the rules. Also, an explanatory note has been added in this section. A new section in Appendix 6G, section G.2.3 has been added to make it explicit that for a given period, actual load distribution of non-dispatch able load over all the nodes will be used to determine load disposition, which is used to determine LPF.

4. Assessment against Section 46(4) of the Electricity Act

- The rule modification does not unjustly discriminates in favour of or against a market participant or a class of market participants;
- It is consistent with the functions and duties of the Authorities under section 3(3) (b) (ii) of the Electricity Act to promote economic efficiency in the electricity industry.

5. Conclusion

The current methodology calculates load participation factors only once every quarter making it static for that quarter. Therefore, it is unable to capture changes in the load distribution over the power system in a particular period. This results in inefficient market outcome. The proposed methodology addresses this issue and improves the market outcome.

6. Impact on market systems

Some changes to the EMC IT systems and testing will be required. No impact on PSO and MSSL systems is anticipated.

[5] In case of the example in Annex 2, use of dynamic LPFs would have captured load shifting carried out by PSO, preventing occurrence of deficit generation violation penalties.

7. Implementation process

The estimated total time required effecting this change, including testing is 63 days.

8. Consultation

Rules have been published on EMC website and MPs were briefed on the rule change in EMC information forum dated 25th Feb'04. No comments have been received.

9. Legal sign off

Text of rule modification has been vetted by EMC's external legal counsel whose opinion is that the modification reflects the intent of the rule modification as expressed in the analysis section of this paper.

10. Recommendations

The RCP has accepted by consensus the rule change proposal and recommends that the EMC Board

a. **adopt** EMC's rule modification proposal to modify the methodology used to determine load participation factors in Section 7.2.2, chapter 6; section B.3, Appendix 6B and section G.2.3, Appendix 6G as outlined in Annex 1 of this paper, and

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

c. **recommend** that the proposed modification come into force **one week** after the date on which the approval of the Authority is published by the EMC.

ANNEX 1: Proposed rule modification

Existing Rules	**Proposed Rules** (Deletion represented by strikethrough text and addition double underlined.)
Section 7.2.2, Chapter 6 7.2.2 The *nodal load forecasts* described in section 7.2.1 shall be calculated by applying *load* participation factors based on historical *load* disposition for similar days and similar *dispatch periods* to the data received from the *PSO* pursuant to section 6.1.1.3. The *load* participation factors shall be calculated and updated from time to time by the *EMC* on the basis of either historic metering data or SCADA data, as the *EMC* deems appropriate.	Section 7.2.2, Chapter 6 7.2.2 The *nodal load forecasts* described in section 7.2.1, comprising a forecast of *load* for each *dispatch network node* for the relevant *dispatch period*, shall be ~~calculated~~ prepared by applying the *load* participation factors ~~based on historical *load* disposition for similar days and similar *dispatch periods*~~ to the ~~data received from~~ forecast of *non-dispatchable load* provided by the *PSO* ~~pursuant to~~ in accordance with section ~~6.1.1.3.~~G.2.1 of Appendix 6G. The *load* participation ~~factors~~ factor for a given *dispatch period* shall be ~~calculated and updated~~ determined ~~from time to time~~ by the *EMC* using *load* disposition for similar days and similar *dispatch periods*. ~~on the basis of either historic metering data or SCADA data, as the *EMC* deems appropriate~~ *Load* disposition shall be determined by the *EMC* using the data provided by the *PSO* pursuant to section G.2.3 of Appendix 6G or historical *metering data*, as the *EMC* deems appropriate. The *load* participation factors for all *dispatch network nodes* for a given *dispatch period* shall sum to one. The methodology, including revisions thereof, for determining the *load* participation factors shall be *published* by the *EMC*. Explanatory Note: The phrase "*load* disposition for similar days and similar dispatch periods" is explained in the aforesaid *published* methodology.

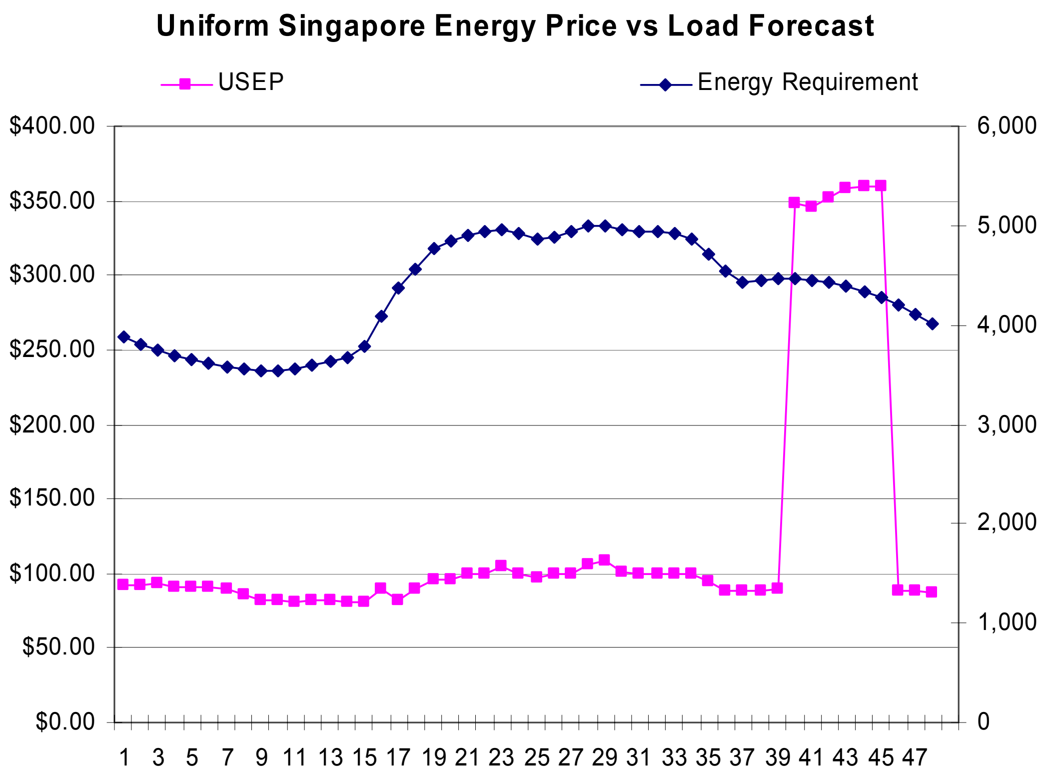
Existing Rules	**Proposed Rules** (Deletion represented by strikethrough text and addition double underlined.)
Section B.3, Appendix 6B **B.3 NODAL LOAD FORECAST** B.3.1 A *nodal load forecast* for that *dispatch period* comprising a forecast of *load* for each *dispatch network node*, which shall be prepared by applying *load* participation factors to the forecast *non-dispatchable load* for Singapore as specified by the *PSO* in accordance with section G.2.1 of Appendix 6G. A *load* participation factor shall be defined by the *EMC* for each *dispatch network node*, based on historic *load* and the *EMC's* reasonable expectation of future conditions. The *load* participation factors for all *dispatch network nodes* shall sum to one. The methodology for determining the *load* participation factor shall be *published*.	Section B.3, Appendix 6B **B.3 NODAL LOAD FORECAST** B.3.1 The relevant *nodal load forecast* prescribed in the provisions of Chapter 6. ~~A *nodal load forecast* for that *dispatch period* comprising a forecast of *load* for each *dispatch network node*, which shall be prepared by applying *load* participation factors to the forecast *non-dispatchable load* for Singapore as specified by the *PSO* in accordance with section G.2.1 of Appendix 6G. A *load* participation factor shall be defined by the *EMC* for each *dispatch network node*, based on historic *load* and the *EMC's* reasonable expectation of future conditions. The *load* participation factors for all *dispatch network nodes* shall sum to one. The methodology for determining the *load* participation factor shall be *published*.~~
	New section G.2.3 of Appendix 6G G.2.3 The actual distribution of *non-dispatchable load* over all the *dispatch network nodes* for the current *dispatch period*.

ANNEX 2

Energy Violation on 3 Jun 03 for P40 to P45

RTS from period 40 to period 45 on 03 June 2003

The USEP-Demand curve on 03 June 2003 is as below:

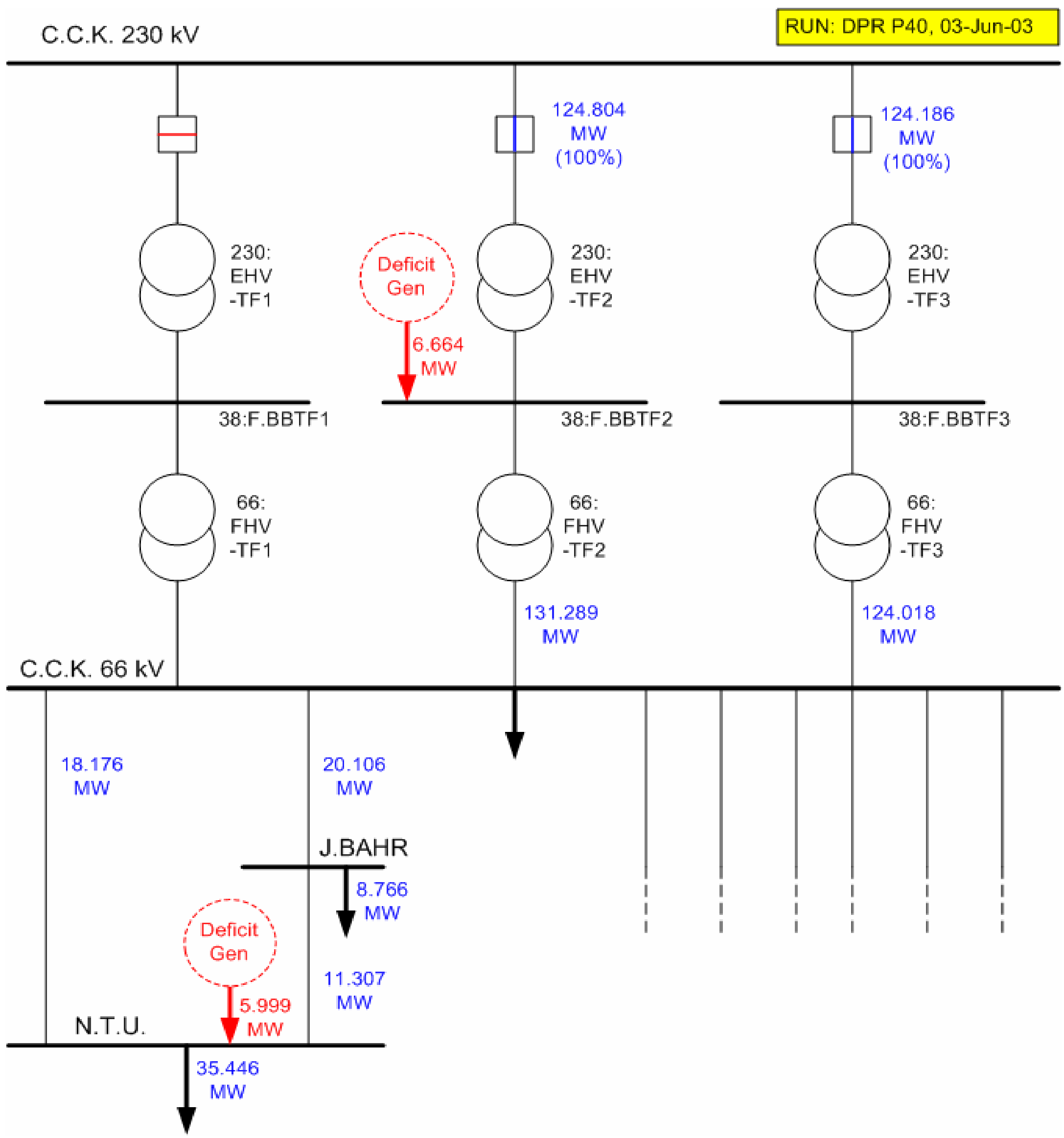


The USEP for P40 to P45 is about $350, while the MNN prices are just around $90. The node (bus) violation explains why the USEP prices are high in these periods.

ANALYSIS

According to the outage schedules, the transformer C.C.K. 230/66 kV TF1 is taken out of service from period 21 (but it was delayed to period 28 for some reason). The absence of this transformer caused heavy loading on the other two parallel transformers. With demand going up, this resulted in energy deficit on the bus C.C.K.:38:F.BBTF2 and N.T.U.:66:BUSBAR1

The one-line diagram of this area for Period 40 is as follow's:



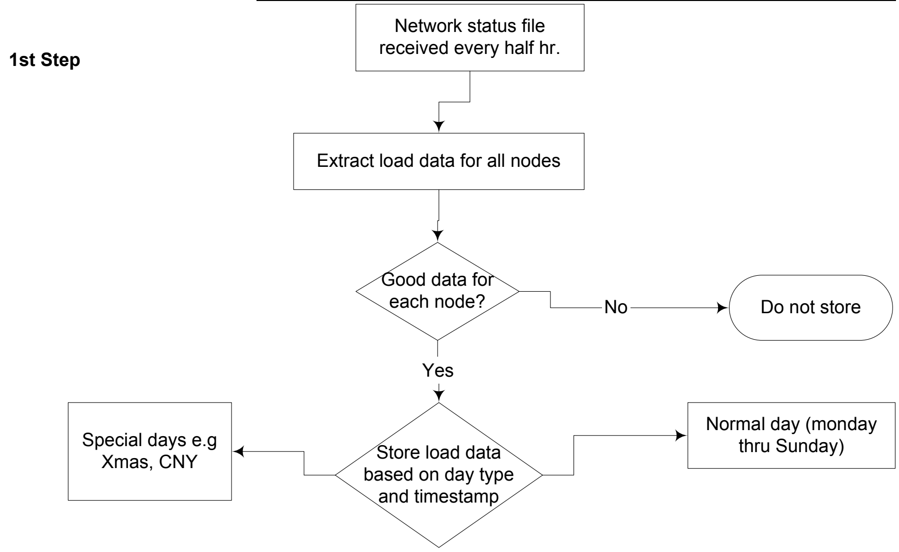
Due to the outage of C.C.K. 230/66 kV TF1, the flow reached 100% on both C.C.K. 230/66 kV TF2 and TF3, as shown in the diagram above. However, this still could not provide sufficient energy to meet the withdrawal requirement on C.C.K. 66 kV bus bar, which resulted in the energy deficit on the bus C.C.K.:38:F.BBTF2 and N.T.U.:66:BUSBAR1. The MCE solution thus showed violation penalties.

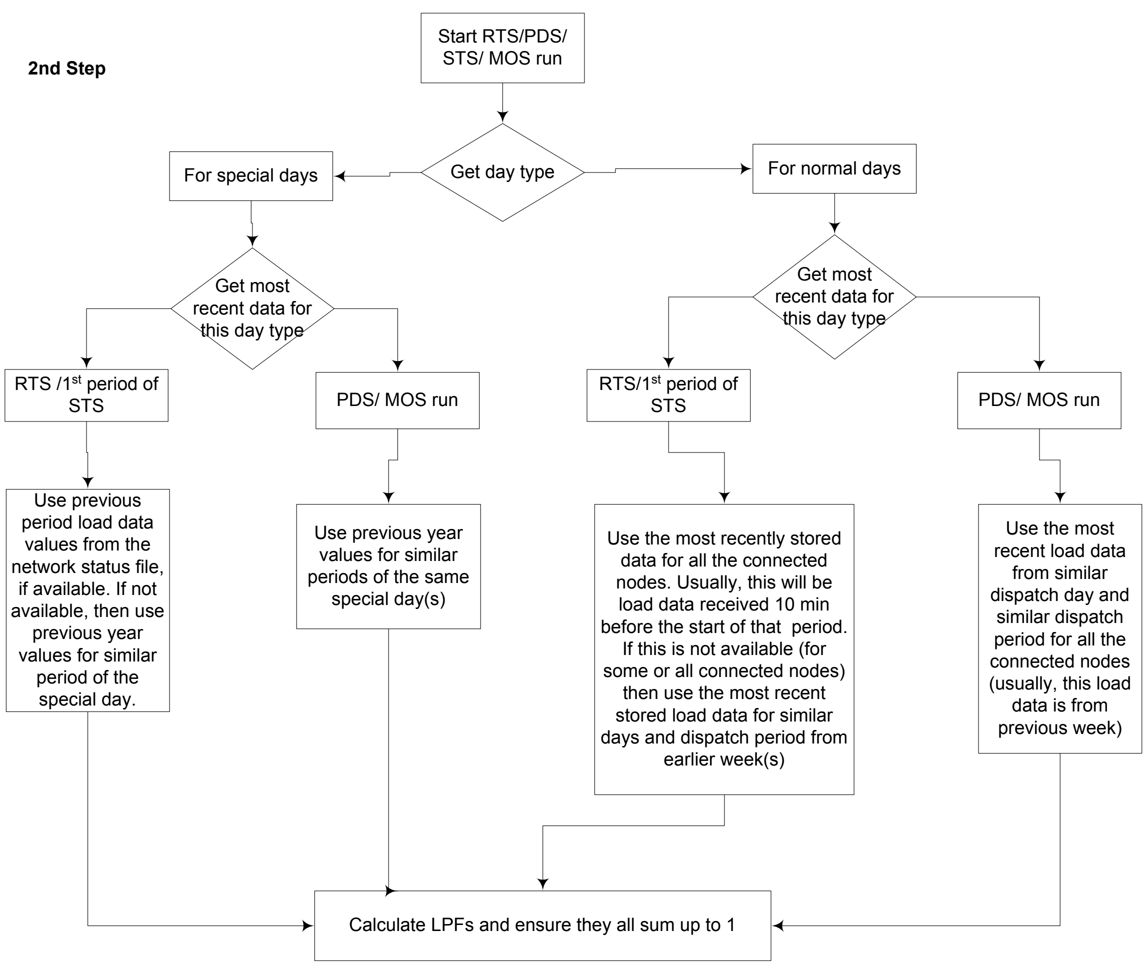
Physically, in this case, the PSO shifted the load (load shifting) in the distribution side[6] (below 22 kV lines) of the network such that there was no real energy deficit anywhere in the network. (Load shifting means load at a particular point is served by power from other circuits, which effectively prevents overloading of existing circuits) The static nature of the LPF could not capture this load shifting, resulting in high USEP for these periods.

In the above case, using dynamic LPFs would have prevented occurrence of energy violations since the network status file for the upcoming period would have captured the reduced load at NTU bus bar as a result of load shifting carried out by the PSO.

[6] MCE models lines down to 66kV only. Thus, load re-distribution over 22kV lines will not be captured by MCE. However, such changes directly affect the load distribution on 66KV lines, enabling MCE to capture it.

ANNEX 3 –Flow chart for proposed methodology





Annex 4- Methodology

Determination of Load Participation Factors

Introduction

This document describes the methodology for determining Load Participation Factors (LPFs) following the change to a system of dynamic LPF calculation. The change to a dynamic calculation was made so that the Market Clearing Engine will use the latest available load distribution when determining the nodal load forecast.

The previous system used a set of pre-calculated LPFs that were updated every three months. Occasionally significant load shifts are effected by the PSO in order to prevent cable overloads. Because the static LPFs did not capture revised load distribution, loads that were shifted in reality were not shifted in the schedule. Hence cable overloads that were prevented in the real system could still exist in the schedule, resulting in binding constraints and corresponding price distortions.

This document first discusses the use of LPFs in the calculation of the nodal load forecast, then the dynamic calculation of the LPFs themselves. This is followed by the process for gathering the data used in the LPF calculation. Finally an example is presented to illustrate the process of data gathering and LPF calculation.

Determination of the Nodal Load Forecast

For each period that is solved a nodal load forecast is calculated for every connected dispatch network node that has non-dispatchable load. In the Market Clearing Engine a dispatch network node with non-dispatchable load is modelled as an Off Take Load facility (OTL)[7].

The PSO system Load Forecast for a given period is distributed among the connected OTLs by using Load Participation Factors (LPFs). The LPFs are calculated specifically for the period being solved, based on the expected load distribution for the connected OTLs. Full details of the LPF calculation are presented in the next section.

The nodal load forecast for an OTL is calculated as follows:

$LF_{OTL} = LPF_{OTL} * LF_{PSO} / (\text{Sum } LPF_{\text{Connected OTLs}})$

where:

LF_{OTL} is the nodal load forecast for the OTL
LPF_{OTL} is the LPF for the OTL
LF_{PSO} is the system Load Forecast provided by the PSO
Sum $LPF_{\text{Connected OTLs}}$ is the sum of the LPFs for all the connected OTLs

[7] In physical reality an OTL is a load transformer.

Calculation of LPFs

The LPF for an OTL represents its share of the total system load. The LPFs are calculated based on historical load distribution. The historical load distribution is determined from actual loads that are stored in the database. The storage of actual load values is covered in more detail in the following section.

Load distribution varies from period to period and day to day, hence the LPFs for a given period are calculated from the most recently stored loads for a similar day and dispatch period. This is referred to in the rules as "load disposition for a similar day and period". For example:

- when solving period 12 on Tuesday the LPFs will be calculated from the most recently stored loads for period 12 on a Tuesday
- when solving for period 7 on Christmas Day the LPFs will be calculated from the most recently stored loads for period 7 on a Christmas Day

So that they MCE can decide which day is a "similar day", every day of the year is assigned to one of the day-types shown in the table below. The day-types consist of the days of the week (i.e. Monday to Sunday), and defined special days (e.g. Christmas Day).

Table 1: Day types currently stored in the system

Day-type	Special Day
Monday	No
Tuesday	No
Wednesday	No
Thursday	No
Friday	No
Saturday	No
Sunday	No
New Years Day	Yes
Chinese New Year Day 1	Yes
Good Friday	Yes
Labour Day	Yes
Vesak Day	Yes
National Day	Yes
Deepavaali	Yes
Christmas Day	Yes
Hari Raya Haji	Yes
Hari Raya Puasa	Yes
Chinese New Year Day 2	Yes

An LPF is calculated for every OTL connected in the period being solved[8]. The LPF for an OTL will be calculated by dividing the most recently stored historical load for that OTL by the sum of the most recently stored loads for all OTLs connected in that period:

[8] For Real Time Schedules this connectivity is determined by the Network Status file received ten minutes before the period starts. For the Forecast Schedules connectivity is determined by the PSO Outage Schedule.

LPF_{OTL} = (Most Recent $Load_{OTL)}$ / (Sum Most Recent $Loads_{All\ Connected\ OTL}$)

where:

LPF_{OTL} is the dynamic LPF calculated for the OTL
Most Recent $Load_{OTL}$ is the most recently stored load value for the OTL
Sum Most Recent $Loads_{All\ Connected\ OTL}$ is the sum of the most recently stored load values for all the connected OTLs

Storage of Actual Load Values

The LPFs are calculated from stored loads. The loads that are stored for a given period are extracted from the Network Status file that is provided by the PSO ten minutes before the start of that period. For example the load that is stored for period 22 (the half hour starting 10:30) will be extracted from the Network Status file that arrives at 10:20.

This will allow the Real Time Schedule to use the most recently available load distribution. If the PSO shift load then this will be reflected in the Real Time Schedule.

Rules for Storing Load Values

The load values that are extracted from the Network Status file will be subject to checking:

- Only load values that have a status of "actual" will be stored i.e. values that are flagged as bad will not be stored[9]
- If a load value is negative then a value of zero will be stored[10]

Fallback Data

To cover the case where a connected node has never had any actual load value recorded in a Network Status file there will be a set of fallback loads.

At the time that Dynamic LPF change is released a set of loads will be stored for every OTL facility that exists in the system at that time[11]. These loads will have an earlier time-stamp than any values subsequently stored from a Network Status file. Hence whenever an OTL has a load value stored from the Network Status file for a particular day-type and period then this value will effectively supersede the fallback value.

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[9] The data in the Network Status file has a quality flag associated with it. Data that is flagged as ACT is actual, good data. Data that is flagged as NOT is bad data.
[10] The load data represents the energy flowing out through a load transformer. If this load transformer is supplying an area where there is embedded generation then potentially energy could flow back into the grid. In this case the load recorded at the transformer would be negative. It is not possible to assign negative load, so in the cases where the load is recorded as negative a value of zero is stored.
[11] These fallback values will be loads that were calculated using the LPFs that used prior to the release of Dynamic LPFs

In the event that a new OTL facility is created, at the time of its creation it will have a load value of zero stored for all periods and day-types. Hence zero will be the fallback value for this OTL, until Network Status file actual load values from are stored.

In most cases the Network Status file will contain values for all connected OTLs. It is unlikely that an OTL that is modelled as connected in the Network Status file will not have a load value stored. Hence the Real Time schedule will usually calculate the LPFs for all nodes from the actual loads stored in the latest Network Status file.

Example - Calculation of LPFs

This is example is fabricated in order to illustrate the key points of the preceding methodology.

Calculation of LPFs for 23-March Period 12 (half hour starting 05:30):

Network Status File: arrives approximately 10 minutes before Period 12 i.e. 23-March 05:20, containing the following actual MW load values:

Node	**node A**	**node B**	**node C**	**node D**	**node E**
MW Load	10.2	9.6	-	-5.7	13
Quality	good	bad	-	good	good

The table below shows the status of the actual MW load stored in the database, after the Network Status file shown above has been processed. The records are shown in chronological order. Only representative days and periods are shown, with ellipses to mark the absence of intervening records.

Timestamp	**Day Type**	**Period**	**node A MW**	**node B MW**	**node C MW**	**node D MW**	**node E MW**
date/time of Dynamic LPFs Release	Tuesday	12	10.1	9.8	6.1	2	-
…							
…							
date/time of Standing Data release for new node E	Tuesday	12	-	-	-	-	0
…							
…							
16-March 05:21	Tuesday	12	10.3	-	7	1	-
…							
…							
23-March 05:20	Tuesday	12	10.2	-	-	0	13

Note: a value of "-" represents no value stored. In the case of node C this is because it is disconnected. Disconnected nodes are not included in the LPF calculation.

Calculation of LPFs for Real Time Schedule Period 12:

Node	**node A**	**node B**	**node C**	**node D**	**node E**	**Total**
MW Value Used	10.2	9.8		0	13	33
calc'd LPF	10.2 /33 =0.309	9.8 /33 =0.297		0 /33 =0	13 /33 =0.394	1.0

Values used by previous day's Pre Dispatch Schedule covering Period 12:

Node	**node A**	**node B**	**node C**	**node D**	**node E**	**Total**
MW Value Used	10.3	9.8	7	1	0	28.1
calc'd LPF	10.3 /28.1 =0.366	9.8 /28.1 =0.349	7 /28.1 =0.249	1 /28.1 =0.036	0 /28.1 =0	1.0

The above example illustrates the following situation:

node A: The good load value received in Network Status File is used
node B: A bad load value received, so the Real Time Schedule LPF calculation uses the latest good value. As no value has ever been stored, the latest good value is the fallback value
node C: No value is received. This is because the node is not connected. Because the node is not connected it is not included in the Real Time Schedule LPF calculation.
node D: Negative value received, stored as 0
node E: Did not exist at the time Dynamic LPFs was released. When the OTL was created a value of 0 was entered for all periods and day-types. The value of 0 was used until a value of 13 was received in the Network Status file.

Note:

- This example assumes the entire network consists of only the OTL facilities shown. The actual system has approximately 370 OTL facilities.
- In most cases the actual load values that are used will all be extracted from the same Network Status file, as missing and bad values are uncommon
- Because this is an exaggerated example, the LPFs vary significantly between the Pre Dispatch Schedule and the Real Time Schedule. In reality this would not be the case, as load distribution and node connectivity does not vary greatly from day to day. Also the removal of one or two nodes has no significant effect on the overall outcome.