PUBLIC

WESM Manual

Load Forecasting Methodology

Issue 4.0 | WESM-LFM

This Market Manual sets out the procedures for determining load forecast used in the relevant market runs in the Philippine Wholesale Electricity Spot Market.

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In case of inconsistency between this document and the DOE Circulars, the latter shall prevail.

Document Change History

Issue No.	Proponent	Date of Effectivity	Reason for Amendment
0.0	MO Sub-com	2004-08-09	New Document
0.1	MO Sub-com	2004-08-17	Sub-com members comment incorporated
2.0	PEMC	2014-04-17	Entire document revised in accordance with recommendations made in the report on the operational audit of the market operator systems and processes.
3.0	PEMC	26 Jun 2021	Revised to incorporate changes to forecasting methodologies and definition of nodal load distribution factors in accordance with the enhancements to WESM operations under DOE DC 2015-10-0015
4.0	IEMOP		Revised to include the procedures for preparing and updating Load Distribution Factors (LDFs)*
	PEMC		Revised formatting for the commencement of the enhanced WESM design and operations per DOE Department Circular No. DC2021-06-0015.

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Document Approval

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Declaring the Commercial Operations of Enhanced WESM Design and Providing Further Policies

Reference Documents

Document ID.	Document Title
	WESM Rules
	Philippine Grid Code
WESM-DP	Dispatch Protocol
	PA Consulting Group. *Philippine Electricity Market Corporation. 2012 Independent Audit Summary Report* (12 December 2012).

Contents

SECTION 1   INTRODUCTION

1.1.   Background

1.1.1.   *Load forecasts* are necessary inputs to the optimization runs in the *Wholesale Electricity Spot Market* (WESM), particularly the *week-ahead projection, day-ahead projection, hour-ahead projection*, and the *real time dispatch market runs*. The responsibility to prepare *load forecasts* rests in the *Market Operator* although *Customers* are also permitted to perform their own customer forecasts under certain conditions.

1.1.2.   The *WESM Rules* provide for the responsibilities of the *Market Operator* in performing its *load forecasts*:

a.   *WESM Rules* Clause 3.7.4.1 (c) requires that each *market projection* shall take into account the forecast demand information prepared by the *Market Operator* in accordance with *WESM Rules* Clause 3.5.4.

b.   *WESM Rules* Clause 3.7.4.2 further requires that prior to the preparation of each set of *market projections,* the *Market Operator* shall, in consultation with the *System Operator*, prepare an expected unrestrained *net load forecast* in accordance with the procedures developed under Clause 3.5.4, and such number of other load scenarios as may be determined in consultation with *WESM Participants* and approved by the *PEM Board.*

c.   For the *real-time dispatch market runs*, *WESM Rules* Clause 3.8.1 (b) and (c) directs that at the beginning of each interval, the *Market Operator* shall prepare a forecast of the *unrestrained net load* expected at each market trading node for the end of that trading interval, and adjust that *unrestrained net load forecast* to account for *load shedding*, if required, in accordance with *WESM Rules* clause 3.9.5.

d.   Furthermore, *WESM Rules* Clause 3.5.4.2 states that each net *load forecast* shall be prepared in such a way as to represent the net *load* to be met by *generation* from *scheduled generating units, must-dispatch generating units, priority dispatch generating units*, and *non-scheduled generating units* including losses occurring outside the system represented by the *market network model*, but excluding any *scheduled load*.

e.   *WESM Rules* Clause 3.5.4.3 states that the *unrestrained net load forecast* shall be prepared so as to represent the *net load* as it would be, or would have been, in the absence of *load shedding*.

f.   *WESM Rules* Clause 3.5.4.4 states that if *load shedding* is expected to occur in any *dispatch interval*, a r*estrained net load forecast* for that *dispatch interval* shall be prepared on the same basis, but accounting for *load shedding* to the extent that it is expected to occur.

1.1.3. *Customers* are permitted under *WESM Rules* Clause 3.5.4.1 to submit their own *load forecast* that shall be used by the *Market Operator* in the preparation of *net load forecast* subject to certain conditions.

   a.   Each *Customer* may submit a forecast in respect of each *dispatch interval* for each of its registered *load* facilities for each trading day of week in accordance with the *WESM timetable*. The *timetable* is set out in Section 4 of the *WESM* Dispatch Protocol.

   b.   The forecasted load shall be used by the *Market Operator* in the preparation of the *net load forecast.*

   c.   If the *Customer fails* to submit a forecast for his *load* facility in accordance with the *WESM timetable,* then the forecast prepared by the *Market Operator* at the relevant *node* shall be used.

1.2.   Purpose

This *Market Manual* establishes the following:

1.2.1. The requirements in determining the *load forecasts* for the following *market runs* in the *WESM*:
   a.   *Market Projections*
      i.   *Week-Ahead Projection* (WAP)
      ii.   *Day-Ahead Projection* (DAP)
      iii. *Hour-Ahead Projection* (HAP)
   b.   *Real-time Dispatch*

1.2.2.   The forecast methodology to be employed by the *Market Operator* for preparing load forecasts.

1.3.   Scope

The systems, processes and procedures set out in this *Market Manual* shall be used in the preparation of *load forecasts* to be used for the *week-ahead projections (*WAP)*, day-ahead projections* (DAP), *hour-ahead projections* (HAP), and *real-time dispatch market runs* in the *WESM*.

SECTION 2   DEFINITIONS, REFERENCES, AND INTERPRETATION

2.1.   Definitions

2.1.1.   Unless otherwise defined in this section or the context implies otherwise, the italicized terms used in this *Market Manual* shall bear the same meaning as defined in the *WESM Rules*.

2.1.2. In addition, the following words and phrases as used in this *Market Manual* shall have the following meaning -

a. **Demand.** Total power consumed in a *power system* or *grid* inclusive of the relevant losses produced during the delivery of power. It is also the total power generated in the *grid.*

b. **Demand Forecast.** *Demand* projection for a particular *forecast area.*

c. **Final Demand Forecast**. Sum of the *net load forecasts* plus the losses in a *forecast area*

d. **Forecast Area.** A *grid* in the Philippine *power system* where *demand forecast* will be applied. Currently, each *grid* in the Philippines is designated as a *forecast area*, namely the Luzon, the Visayas, and the Mindanao *grids.*

e. **Input Demand Forecast**. Initially assumed *demand forecast* that shall be used as the off-take for determining the *unrestrained net load forecast.*

f. **Load Distribution Factor (LDF).** Factor used in allocating the total projected *load* to individual *loads* in the *market network model.*

g. **Market Management System (MMS).** Infrastructure that supports the operations of the *WESM* and which includes functionalities that support the processes set out in this *Market Manual.*

h. **Real-time Dispatch.** Otherwise known as RTD. It is the *dispatch schedule* which determines the target loading of facilities at the end of the *dispatch interval.* The RTD calculates the ex-ante *nodal energy dispatch prices.*

i. **Short-Term Load Forecast.** Hourly *demand forecasts* starting at the next hour up to seven days ahead. It shall be applied to the calculation of the *week-ahead projection* and *day-ahead projection.*

j. **Unrestrained net load forecast.** Also refers to *unrestrained load.*

k. **Very Short-Term Load Forecast.** *Demand forecasts* for each *dispatch interval* starting at the next *dispatch interval* up to the next two hours. It shall be applied to the calculation of the *hour-ahead projection* and *real-time dispatch.*

l. **Weather Area.** A specific location where there is available weather data.

2.2.   References

This *Market Manual* shall be read in association with the *WESM Rules* and other relevant *Market Manuals.*

2.3. Interpretation

2.3.1. Any reference to a clause in any section of this *Market Manual* shall refer to the particular clause of the same section in which the reference is made, unless otherwise specified or the context provides otherwise.

2.3.2. Where there is a discrepancy or conflict between this *Market Manual* and the *WESM Rules*, the *WESM Rules* shall prevail.

2.3.3. Standards and policies appended to, or referenced in, this *Market Manual* shall provide a supporting framework.

SECTION 3 RESPONSIBILITIES

3.1. Market Operator

3.1.1. The *Market Operator* shall prepare *net load forecasts* for each *customer market trading node* in accordance with the methodology set out in this *Market Manual.*

3.1.2. The *Market Operator* shall be primarily responsible for the development and review of the *load forecasting* methodology documented in this *Market Manual.*

3.2. System Operator

3.2.1. The *System Operator* shall provide the information required by the *Market Operator* in accordance with this *Market Manual*, and ensure such information's accuracy.

3.2.2. The *System Operator* shall assist the *Market Operator* in improving the *load forecasting* methodology set out in this *Market Manual.*

3.3. Trading Participants

3.3.1. The *Trading Participants* shall carry out the responsibilities provided for in this *Market Manual.*

3.3.2. *Customer Trading Participants* that opted to provide *net load forecasts* for their respective facilities shall be responsible for the timely submission and accuracy of their forecast information.

SECTION 4	SHORT-TERM LOAD FORECAST

4.1. Background

4.1.1. Hourly *demand forecasts* for each *forecast area* from the current day to the next seven (7) days shall be determined by the *Market Operator* using the *Market Management System's Short-Term Load Forecast (STLF)* application.

4.1.2. The aforementioned hourly *demand forecasts* shall be used as *input demand forecasts* to obtain the hourly *unrestrained net load forecasts* for the *week-ahead projection* (WAP) and the *day-ahead projection* (DAP).

4.1.3. The summation of the *net load forecast* plus the losses computed for a *forecast area* after the optimization process in the relevant *market run* (i.e., WAP or DAP) constitutes the *final demand forecast* for that *forecast area*.

4.1.4. The procedures for obtaining the *net load forecasts* from the *demand forecasts* using *load distribution factors* (LDF) are discussed further in Section 6 of this *Market Manual.*

4.2. Determination of Hourly Demand Forecasts

4.2.1. The process of determining hourly *demand forecasts* involve various input data such as historical *demand*, historical weather measurements, and weather forecast data.

4.2.2. Each *forecast area* is mapped to a *Weather Area*, which has its own distinct historical weather and forecasted weather information.

4.2.3. Hourly *demand forecasts* are determined using the MMS' STLF application's weather adaptive, similar day, and pattern matching algorithms as shown in the illustration below. The methodology behind these forecasting algorithms are further discussed in Section 11.
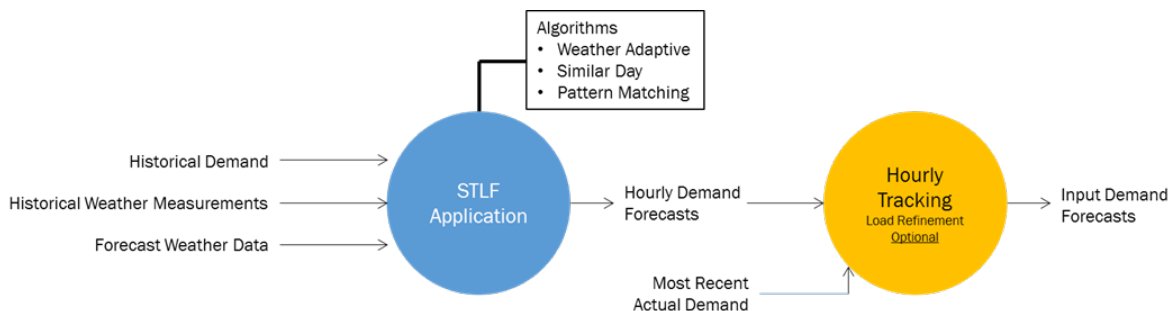

Figure 1. Process Overview for Determining Hourly Demand Forecasts via MMS-STLF

4.2.4. The *Market Operator* may use other forecasting algorithms to determine hourly *demand forecasts* for each *forecast area*.

4.2.5.   The *demand forecast* determined by the *Market Operator* outside of the MMS' forecasting algorithm shall be treated as an external *demand forecast*.

4.2.6.   If an external *demand forecast* is provided by the *Market Operator* in a relevant hourly interval, then the external *demand forecast* shall be considered as the *input demand forecast* regardless of any existing *demand forecast* determined by the MMS. These hourly *demand forecasts* shall be included in the MO's performance standards.

4.2.7.   Pursuant to *WESM Rules* Clauses 3.7.4.2 and 3.7.4.3, the *Market Operator* shall prepare a *market projection* corresponding to each *load* scenario as may be determined in consultation with *WESM Participants* and approved by the *PEM Board.*

4.2.8.   Load scenarios shall be provided for each *day-ahead projection* using the following sensitivities (increments/decrements) with respect to the *input demand forecast* provided:

Table 1. DAP Load Scenarios

DAP Load Scenario	Increment (+) / Decrement (-), %
Load Scenario 1	– 5 %
Load Scenario 2	– 3 %
Load Scenario 3	+ 3 %
Load Scenario 4	+ 5 %

SECTION 5   VERY SHORT-TERM LOAD FORECAST

5.1.   Background

5.1.1.   *Demand forecasts* for each 5-minute interval in the next two (2) hours in each *forecast area* shall be determined by the *Market Operator* using the *Market Management System's Very Short-Term Load Forecast* (VSTLF) application.

5.1.2.   The *demand forecasts* for each 5-minute interval in the next two (2) hours shall be used as *input demand forecasts* to obtain the *unrestrained net load forecasts* for the *hour-ahead projection* (HAP) and the *real-time dispatch* (RTD).

5.1.3.   The summation of the *net load forecast* plus the losses computed for a *forecast area* after the optimization process in the relevant HAP or RTD run constitutes the *final demand forecast* for that *forecast area*.

5.2.   Determination of *Demand Forecasts* for Each Dispatch Interval

5.2.1.   The VSTLF uses historical *demand* data and shall be represented in a time-series.

5.2.2.   From the *demand* time-series data, *demand forecast* shall be determined using the Cubic-Spline Interpolation Method, which details are discussed in Appendix D.

SECTION 6   NET LOAD FORECASTS

6.1.   Scope

Pursuant to *WESM Rules* Clause 3.5.4.1, this section provides the *Market Operator's* preparation of *net load forecasts,* which are either *unrestrained* or *restrained,* for *market projections* and *real-time dispatch market runs*.

6.2.   Unrestrained Net Load Forecast

6.2.1.   The *unrestrained net load forecast* is prepared by the *Market Operator* by allocating the *input demand forecast* net of an initial loss percentage with respect to the *Load Distribution Factors* (LDF) set for each *customer market trading node*.

6.2.2.   LDFs are defined for each *customer market trading node* that belongs to a specific *forecast area*, for each day and hour.

6.2.3.   The *Market Operator* shall prepare and update the LDF of each *customer market trading node* in accordance with Appendix F.

6.2.4.   The following figure shows the process of how *unrestrained net load forecasts* are determined from *input demand forecasts* using LDFs.
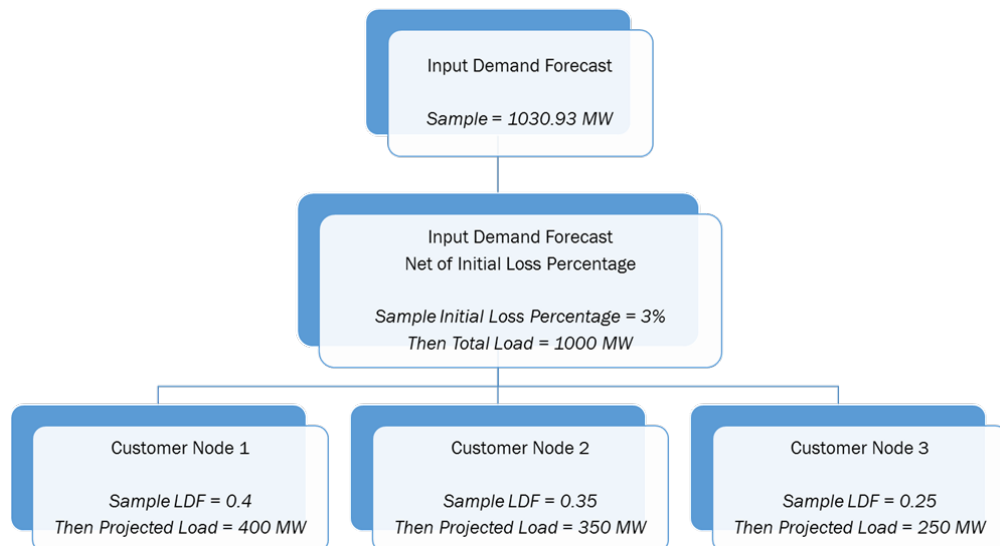

Figure 2. Determination of Unrestrained Net Load Forecasts for each Customer Market Trading Node

6.2.5. The total *unrestrained net load forecast* can be interpreted in the following equation:

$$\text{Total UNLF} = \textit{Demand Forecast} \times \left(1 - \text{Initial Loss Percentage}_{FA}\right)$$

Where:

UNLF	refers to unrestrained net load forecast
Initial Loss Percentage$_{FA}$	refers to initial loss percentage in FA
FA	refers to forecast area

6.2.6. The *unrestrained net load forecast* of each *customer market trading node* shall be obtained by pro-rating the total *unrestrained net load forecast* to the actual load of each *customer market trading node* based on the latest actual *system snapshot* from the *System Operator.* This is provided in the following equation:

$$\text{UNLF}_b = \frac{\text{Total UNLF}}{\text{Total LDF}_{h,\ FA}} \times \text{LDF}_{b,\ h,\ FA}$$

Where:

UNLF$_b$	refers to *unrestrained net load forecast* of *customer market trading node b*
Total LDF Load$_{h,\ FA}$	refers to the sum of *load distribution factors* for hour *h* in a *forecast area FA* where *customer market trading node b* belongs
LDF$_{b,\ h,\ FA}$	refers to the *load distribution factor* of *customer market trading node b* for hour *h* in *forecast area FA*

6.2.7. A *Trading Participant* may submit his own *unrestrained net load forecast.* Further details on customer forecasts are available in SECTION 7.

6.3. *RESTRAINED NET LOAD FORECAST*

6.3.1. The *Restrained Net Load Forecast* of each Customer Market Trading Node is achieved after the optimization process of the Market Dispatch Optimization Model (MDOM).

6.3.2. A Customer Market Trading Node's projected load will be shed should its price reach the level of the Nodal VoLL price.

6.3.3. The *Restrained Net Load Forecast* shall then be obtained after the MDOM determines a solution reflective of load shedding. The following equation shows the value of the *Restrained Net Load Forecast*.

$$\text{RNLF}_b = \text{UNLF}_b - \text{Load Shed}_b$$

Where:

RNLF$_b$	refers to the *Restrained Net Load Forecast* of Customer Market Trading Node b
UNLF$_b$	refers to the *Unrestrained Net Load Forecast* of Customer Market Trading Node b
Load Shed$_b$	refers to the amount of load to be shed at Customer Market Trading Node b

6.4. INITIAL LOSS PERCENTAGE

6.4.1. The Initial Loss Percentage is the percentage of the *Demand Forecast* initially assumed to be the loss. It shall be netted out of the *Demand Forecast* in order to achieve the Total *Unrestrained Net Load Forecast*, which shall then be used to obtain the *Unrestrained Net Load Forecast* of each *customer market trading node.*

6.4.2. Each *Forecast Area* has its own Initial Loss Percentage, and it shall be reviewed on an annual basis by the *Market Operator*. The Initial Loss Percentage per *Forecast Area* shall be published by the *Market Operator* in the *Market Information Website*[1].

SECTION 7   CUSTOMER FORECASTS

7.1. CUSTOMER FORECAST SUBMISSION

7.1.1. Each qualified *Customer*, except those that are required by the *Market Operator* based on Section 7.1.6, may at its option, submit forecasts for its respective *market trading node* for each hourly or *dispatch interval.*

7.1.2. A *Customer* may only submit a *load forecast* for a *market trading node* that is solely registered to them.

7.1.3. Each *Customer* that submits *load forecasts* for the *market projections* and the *real-time dispatch* shall upload the relevant forecast in accordance with the *WESM timetable*.

7.1.4. The *Customer* forecast shall represent the estimated aggregate *demand* at the *market trading node* and shall be in real-power quantities (MW).

7.1.5. *Customer* forecasts submitted by *Trading Participants* shall replace the *Unrestrained Net Load Forecast* determined in Section 6.2 of this *Market Manual.*

7.1.6. Should a *customer market trading node* have a definite MW loading that can materially affect *WESM's* pricing and scheduling, then the *Market Operator* shall require the relevant *Trading Participant* to submit *Customer* forecasts for the identified *market trading node* for each interval in accordance with the *WESM timetable.*

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[1]http://www.wesm.ph

7.1.7. Submission of *Customer* Forecasts in the *WESM* shall be made via *the Market Management System's* Market Participant Interface (MPI).

7.2. CUSTOMER LOAD FORECAST CONSIDERATIONS

Trading Participants submitting *customer load forecasts* shall consider the following when determining *Net Load Forecasts* for their relevant *market trading nodes*.

1. **Customer Forecast Methodology**. In preparing the *load forecast,* the *customers* may select the methodology that they believe is most appropriate for each individual *market trading node.*

2. **Customer Load Forecast Adjustment**. Load adjustment factors shall be established by the *Customer* and his *Meter Service Provider.* The adjustment factors shall consider site-specific losses and other factors deemed necessary to reflect accurate *customer load forecast* at his *market trading node*.

3. **Customer Forecast Timeline**. *Customers* may be able to provide their own *load forecast* based on the Open Market Window defined in the *WESM* Dispatch Protocol.

SECTION 8   LOAD FORECASTING PARAMETERS

8.1. WEATHER DATA

8.1.1. Historical and forecast weather data shall be made available to the *Market Management System's* database on a regular interval in accordance with the *WESM timetable.* The weather data shall be based on the major load center located in the *forecast area*. Weather parameters shall include, but not limited to the following.
- Temperature
- Humidity

8.1.2. Such weather information shall be obtained from a reliable source deemed appropriate by the *Market Operator*. Prospective weather data providers are listed in Appendix E.

8.1.3. The *Market Operator* shall maintain a repository of the historical weather-related information.

8.2. DEMAND

8.2.1. *Demand* shall be obtained from the *Network Service Providers'* SCADA system, and it shall be incorporated in the data provided by the *System Operator* to the *Market Operator*.

8.2.2. Real-time information at the nodal levels shall also be retrieved by the *Market Operator* from the *System Operator*. Such information shall be used by the *Market Operator* in preparing the *Demand Forecast* and the *Net Load Forecast*.

8.2.3. In the absence or failure to provide reliable real-time information, the *Market Operator* shall utilize the latest information provided.

8.2.4. *Demand* obtained over time shall form part of the historical hourly load information that shall be used by the *Market Operator* as inputs to the load forecasting algorithms used for *market projections* and *real-time dispatch.*

8.2.5. Customer Demand Forecasts shall be based on the provisions under Section 7.

8.3. POWER SYSTEM CONDITION

8.3.1. The *Market Operator* shall consider the forecasted *power system* condition in the preparation of *net load forecast.* These shall include planned maintenance (transmission, sub-transmission, and generation), large *customer* maintenance schedules, and other activities, including generator testing and commissioning that may have an impact on the preparation of *market projections* and *real-time dispatch.*

8.3.2. The *System Operator* shall ensure that all relevant information is provided to the *Market Operator* in accordance with the *WESM timetable.*

8.3.3. For unplanned power system conditions, the *System Operator* shall ensure that all relevant information is timely provided to the *Market Management System* through the Energy Management System or other means of communication to the *Market Operator*.

8.3.4. All *Trading Participants* shall also ensure that information regarding any unplanned activity or condition is timely provided to the *System Operator*.

8.4. LOAD PROFILE

8.4.1. For similar day load forecasts, the *Market Operator* may utilize static profiling, proxy day profiling, and estimated or deemed profiling or a combination thereof. The *Market Operator* shall use all reasonable endeavors to provide the most appropriate load profile in determining *demand* and *net load forecasts.*

8.4.2. The *Market Operator* may consider typical day representations for any day of the week and season combination. Static profiling shall consider day of the week profile, holidays, and special events profile. The *Market Operator* should note that static profiles do not reflect operating conditions of the day being estimated.

8.4.3. The *Market Operator* may consider selecting a day in history that most closely matches the day being estimated. The proxy day can be chosen based on either on weather forecast and/or system load. Actual data from the sample for the selected proxy day

shall then be used to create the profile. Proxy day profiling shall consider day of the week profile, holidays and special events profile.

8.4.4. The *Market Operator* may obtain *Demand Forecasts* using engineering estimates, if and when necessary, for very predictable loads such as street lighting or residential area from *Trading Participants.*

8.5. LOAD GROWTH

8.5.1. The *Market Operator* shall consider the projected growth of load demand for each *Forecast Area* in the preparation of *Net Load Forecasts.* For consistency, the *Market Operator* shall consider information from the *Department of Energy* (DOE) for the load growth values.

SECTION 9   LOAD FORECAST AUDIT AND PERFORMANCE MEASURES

9.1. The *Market Operator* shall log all transactions performed for the determination of *net load forecast* including the uploading of the optional *Customer's* load demand forecast.

9.2. The *Market Operator* shall monitor the actual and forecasted nodal load for each relevant *market trading node.*

9.3. The *Market Operator* shall evaluate the *Net Load Forecast* Performance.

9.4. The *Market Operator* shall evaluate the *Demand Forecast* Performance pursuant to the performance standards that shall be maintained pursuant to *WESM Rules* Clause 10.4.10.2.

SECTION 10   AMENDMENTS, PUBLICATION AND EFFECTIVITY

10.1. Review and Update

10.1.1. Pursuant to *WESM Rules* Clause 3.5.4.6, the *Market Operator* shall periodically review the methodologies for performing *nodal load forecasts* and update this *Market Manual,* as necessary.

10.1.2. Any amendments or revision to this *Market Manual* shall be approved in accordance with Chapter 8 of the *WESM Rules* and corresponding *Market Manual* on rules change process.

10.2. Publication and Effectivity

The publication and effectivity of this *Market Manual* shall be in accordance with Chapter 8 of the *WESM Rules* and corresponding *Market Manual* on rules change process.

SECTION 11   APPENDIX

Appendix A. Weather Adaptive Algorithm for Short-Term Load Forecast

1. **INPUT DATA SPECIFICATION**

The following input data are necessary to calculate the *load forecast* for this methodology:
   a. Current load data.
   b. Current weather data.
   c. Weather forecast data provided by weather services companies.
   d. Preselected day types for forecasting period.
   e. The prediction error of the last forecast.
   f. Estimated parameter values which quantify the causal relationship among historical load data, historical weather data and day type data.

2. **WEATHER ADAPTIVE USING MULTIPLE REGRESSION METHOD**

The Weather Adaptive Algorithm uses multiple regression analysis to create a statistical relationship between demand and weather conditions, including day types. In this methodology, the regression coefficients are estimated using equally or exponentially weighted minimum mean square error (MMSE) estimation criteria.

The regression analysis is performed with up to 3rd degree polynomial functions. The polynomial degree is adjusted for each weather influencing variable by parameter.

Regression analysis filters the different weather-dependent parts of the load for a given time, for example, time interval 8.00-9.00 a.m., as well as the influence of day type. The result of this filtering process is a set of regression coefficients (polynomial-coefficients).

To detect non-typical historical data, an adjustable data check is implemented. If load or influencing variables violate an adjustable bandwidth, they are excluded from the data analysis.

The result of the analysis is a decomposition of the time-dependent total load Y(t) into:

$$Y(t) = B(t) + a_T T(t) + a_L L(t) + \left[\sum a_W W(t)\right] + D(t) + model\_error(t)$$

Where:
B(t) refers to weather insensitive load component
a_L, L(t) refers to weather-sensitive load components
$a_T,$ T(t) refers to temperature-dependent load
a_L L(t) refers to humidity-dependent load
a_W W(t) refers to other weather-dependent load
D(t) refers to day type-specific load component

model_error (t) refers to the minimized weighted least squares estimation

The model error, is minimized using a weighted least squares technique, and this allows the user to get the forecast results in the form of an analytical expression.

Generally the regression analysis, which involves regression coefficient estimation, is activated periodically together with a subsequent forecast calculation.

3. MODEL ANALYSIS

Model analysis is the process used to find a new set of parameters that reduces the forecast errors for the weather adaptive algorithm. This requires using a particular set of historical load and weather history. Multiple simulations are run which imitate what the Weather Adaptive forecasting calculations would have been for that particular set of data starting at a user defined day and moving through the remaining data one day at a time. Each simulation has a different set of weather adaptive parameters. Results are summarized and may be compared, and therefore help to in analysing points that need further improvement.

4. DETERMINATION OF THE WEATHER FORECAST DATA
In order to get good forecast results the best available weather forecast data are necessary.

For the forecast calculation, the STLF program requires time series in the adjusted time step of each weather variable over the whole forecast period. These values are calculated automatically from the preceding inputs that are listed.

For the temperature influence, the program tracks a standardized curve through the day-specific values of minimum and maximum temperature. This standardized temperature curve is determined from the historical data at each run of the analysis program. The time points of the extreme forecast temperature are extracted from the historical data.

5. DETERMINATION OF THE LOAD FORECAST

The *load forecast* is calculated for each adjusted time step of the forecast period using the regression coefficients and the weather variables forecast as well as type of day.

The forecast program is activated through the following different means
- Periodically at defined time steps
- After each run of the analysis program
- On user request

Appendix B. Similar Day Algorithm for Short-Term Load Forecast

Use the similar day forecast to produce a *Demand Forecast* for a day or a range of days in the forecast period.

The similar day forecast is based on recalculated *Demand* patterns. There are *Demand* increment patterns for each:

- Forecast Area *Demand*
- Month
- Hour/minute
- Day type
- Normal/average weather conditions

The similar day profiles where calculated initially using historical *Demand* data and recalculation is going to be done once a day during midnight processing. Subsequently, they can be reviewed and edited using the STLF User Interface.

Historical load profile (similar day load) has been calculated for each month, hour and day type:

$$LoadProfile_{i,j,k} = \frac{1}{n} \cdot \sum_{l=1}^{n} HistoricalLoad_{i,j,k}$$

And standard deviation for each calculated load profile has been calculated by:

$$StandardDeviation_{i,j,k} = \sqrt{\frac{\sum(HistoricalLoad_{i,j,k} - LoadProfile_{i,j,k})^2}{n}}$$

Where:

i = 1, 2, 3,…12   - month
j = 1, 2, 3,…24   - hour
k = 1, 2, 3,…8   - day type
l = 1, 2, 3,…n   - number of historical days

Forecasting applications supporting the following day types:

Day Type No.	Day Type
1	FRI
2	MON
3	SAT
4	SUN
5	WKD
6	TUE
7	WED
8	THU

The *Demand* similar day patterns are non-weather sensitive, and they provide the average *Demand* in case for normal weather condition for that time of year (defined by month, hour and day type).

The weather increment patterns defined by standard deviation are expected to change under "Hot"/"Cold" weather conditions. Positive increments indicate that load increases in hotter weather conditions than in normal weather conditions. Negative increments indicate the reverse. Under cold weather conditions, the increments are subtracted rather than added to the non-weather sensitive load pattern values.

Appendix C. Pattern Matching Algorithm for Short-Term Load Forecast

The pattern matching algorithm uses a process to filter days that can be used to determine *Demand Forecasts*. The filtering of days is based on a pre-defined set of parameters, namely the type of day and historical weather data.

Based on the values defined in the filter, such as the type of day and the high and low values of temperature, it will select days and then provide an index for its difference. From there, it will assign a weight to be applied to the *Demand* for that day.

Using the weights along with the actual *Demand* for that day, a *Demand Forecast* shall be determined.

Appendix D. Cubic-Spline Interpolation Algorithm for Very Short-Term Load Forecast

1. **CUBIC-SPLINE INTERPOLATION PROCESS**

The 5-minute *Demand Forecast* executes for a time-horizon of 2 hours, or for 24 5-minutes intervals.

The 5-minute forecast-area load forecast makes use of a Cubic Spline Fitting algorithm in conjunction with the load-tracking methodology.

The inputs to the calculation are the hourly *Demand Forecast* as well as the 5-minute historical loads as shown in the figure below.
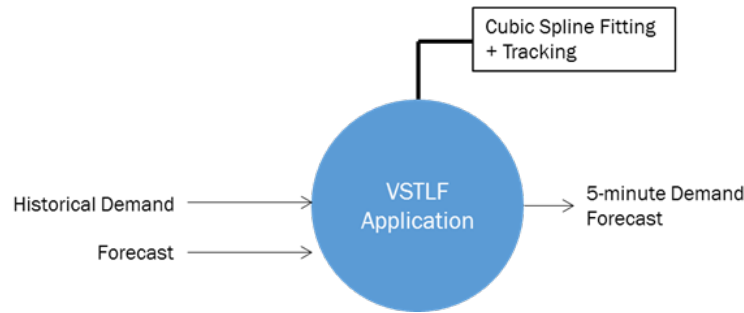

Figure 3. Cubic Spline Process Overview

The Tracking algorithm calculates correction term to the forecast for several 5-minute forecasting period. A curve fitting algorithm is used along with actual *Demand* to calculate the 5 minute forecast.

2. **5-MINUTE TRACKING LOAD FORECAST FUNCTION VIA CUBIC SPLINE**

The tracking forecast is based on deviations between the five minute *Demand Forecasts* and the actual *Demand* every five minutes over the last hour. An average error term is used for the tracking forecast calculation. This average error term is calculated by adapting the relative errors for each time step so that values reflect the recent error trend.

$$\varepsilon_t = \frac{\left[5MinuteLoad_t' - 5MinuteLoad_t\right]}{5MinuteLoad_t}$$

$$A_t = A_{t-1} + \alpha\left[\varepsilon_t - A_{t-1}\right]$$

Where:

$5MinuteLoad_t'$ - 5 minute forecast load at time t

$5MinuteLoad_t$ - 5 minute measured load at time t

ε_t - Relative error at time t

A_t - Average (or adapted) error at time t

α_t - Adaptive parameter ($0 < \alpha_t < 1$)

The correction terms for future time steps are then be calculated as follows:

$$Y_{t+1} = (-1)5MinuteLoad'_{t+1}\left[\beta(\varepsilon_t - A_t) + A_t\right]$$

$$Y_{t+n} = (-1)5MinuteLoad'_{t+n}A_t$$

Where:

Y_t - Forecast correction term for time t

β - Weighting factor for the first future time step

n   - The number of the forecasting time steps (n>1)

The adaptive parameter is selected so that the error from the previous time step does not receive too much weight. The weighting factor is introduced so that the effect of the error for the previous time step may receive additional weight in determining the correction for the next time step.

Appendix E. List of Prospective Weather Data Providers

1. Department of Science and Technology – Philippine Atmospheric, Geophysical, and Astronomical Services Administration (DOST-PAGASA)

2. Accuweather

Appendix F. Procedures for the Preparation and Updating of Nodal Load Distribution Factors (LDF)

LDF Day Types and Hour

1. There are nine (9) day types available, namely:

Table 2. LDF Day Types

Day Type	Day Type Description
1	Monday
2	Tuesday
3	Wednesday
4	Thursday
5	Friday
6	Saturday
7	Sunday
8	Special Day 1
9	Special Day 2

2. By default, a certain day shall have a day type corresponding to its day of the week. For example, 12/19/2019 falls on a Thursday, hence, it shall have a day type of 4 as prescribed in **Table 2. LDF Day Types**.

3. The *Market Operator* may override and choose to update a certain day type that is different from its default type. For example, 12/25/2019 has a default day type of 3 (Wednesday). However, the *Market Operator* may instead define it as belonging to day type 8 (Special Day 1).

4. Day Type 8 and 9 are Special Days that the *Market Operator* may choose in grouping days that represent holidays, or days with significant events. The *Market Operator* shall first evaluate the load profile of candidate days (holidays or days with significant events), then eventually establish which day type the relevant day shall belong to.

5. For this procedure, an hour covers the twelve (12) *dispatch intervals* from the start of that hour (i.e., hour 14 covers the *dispatch interval* ending at 14:05 until the *dispatch interval* ending at 15:00).

Defining Data Source Type of Nodal Loads

1. Each nodal load, except those defined in Section 7.1.6, shall have load distribution factors (LDFs) for each hour of each day type.

2. Each nodal load, except those defined in Section 7.1.6, shall have their respective LDFs updated every five (5) minutes based on either the (a) latest real-time data or (b) from an estimated value.

3. The LDF of a nodal load shall be updated based on latest real-time data if the *Market Operator* assesses that the real-time data for that nodal load is updated regularly; otherwise, the LDF of the nodal load shall be updated by the *Market Operator* based on an estimated value.

Procedure in Updating the Load Distribution Factor

1. Get the day type and hour of the timestamp of the latest available real-time snapshot

For example, if the timestamp of the latest available real-time snapshot is "2019-12-17 14:25", then its day type is 2 by default (12/17/2019 is on a Tuesday), while its hour is 14. The day type and hour obtained here shall be considered as the **reference day type** and **reference hour**.

2. Obtain base MW values for each nodal load

    2.1. For nodal loads with a data source type based on real-time data, the base MW value shall be the latest real-time MW value measured at that nodal load

    $$Base\_MW_{b,D,H,FA} = Nodal\_Actual\_MW_{b,t,FA}$$

    Where:

    $Base\_MW_{b,D,H,FA}$ refers to the base MW for nodal load *b* at reference day type *D* and reference hour *H* in Forecast Area *FA*

    $Nodal\_Actual\_MW_{b,t,FA}$ refers to the MW value measured at nodal load *b* based on the latest actual system snapshot at time *t* in Forecast Area *FA*

    2.2. For nodal loads with a data source type based on an estimated value, the base MW value shall be obtained using the following steps:

    2.2.1. Get the actual demand of the *Forecast Area* considering any import/export from its adjacent *Forecast Area*

    $$Actual\_Demand_{t,FA} = \sum_{i=1}^{n} P_{i,t,FA} + \sum_{a=1}^{p} import_{a,FA,t} - \sum_{a=1}^{p} export_{a,FA,t}$$

    Where:

    $P_{i,t,FA}$ refers to the real power (MW) output of generator *i* based on the latest actual system snapshot at time *t* in Forecast Area *FA*

$\text{import}_{a,FA,t}$ refers to the MW imported from Forecast Area *a* onto Forecast Area *FA* based on the latest actual system snapshot at time *t*

$\text{export}_{a,FA,t}$ refers to the MW exported to Forecast Area *a* from Forecast Area *FA* based on the latest actual system snapshot at time *t*

2.2.2. Obtain the pre-defined estimated loss percentage for the *reference day type* and *reference hour* for the relevant *Forecast Area*. The pre-defined estimated loss percentage is based on historical power flow losses in the real-time dispatch (RTD) solution and is updated regularly by the *Market Operator*. Then, compute for the estimated net load as follows:

$$\text{Est\_Net\_Load}_{t,FA} = \left(1 - \text{Est\_Loss}_{FA,D,H,}\right) \times \text{Actual\_Demand}_{t,FA}$$

Where:

$\text{Est\_Loss}_{FA,D,H}$ refers to the loss percentage estimated for Forecast Area *FA* at day type *D* and hour *H*

2.2.3. The base MW for nodal loads with a data source type based on an estimated value shall be obtained by multiplying its pre-defined load distribution factor at the *reference day type* and *reference hour* to the aforementioned estimated net load. The pre-defined load distribution factor for nodal loads having an estimated value is based on historical metered quantities and is updated regularly by the *Market Operator.*

$$\text{Base\_MW}_{b,D,H,FA} = \text{LDF}_{b,D,H,FA} \times \text{Est\_Net\_Load}_{t,FA}$$

Where:

$\text{LDF}_{b,D,H,FA}$ refers to the load distribution factor of nodal load *b* at day type *D* and hour *H* at Forecast Area *FA*

3. Once all base MW values are obtained for each nodal load b, compute for the new LDFs using the following formula:

$$\text{LDF\_new}_{b,D,H,FA} = \left[\left(\frac{\text{Base\_MW}_{b,D,H,FA}}{\sum_{k=1}^{n} \text{Base\_MW}_{k,D,H,FA}}\right) \times \alpha\right] + \left[\left(\text{LDF\_old}_{b,D,H,FA}\right) \times (1-\alpha)\right]$$

Where:

$\text{LDF\_new}_{b,D,H,FA}$ refers to the new load distribution factor of nodal load *b* for day type *D* and hour *H* at Forecast Area *FA*

$\text{Base\_MW}_{b,D,H,FA}$ refers to the base MW of nodal load *b* for day type *D* and hour *H* at Forecast Area *FA*

$\text{Base\_MW}_{k,D,H,FA}$ refers to the base MW of nodal load k for day type D and hour H at Forecast Area FA

α refers to the smoothing factor (from 0 to 1, is initially set 1, and shall be updated by the *Market Operator* based on a regular assessment to improve forecast accuracy)

$\text{LDF\_old}_{b,D,H,FA}$ refers to the old/current load distribution factor of nodal load b for day type D and hour H at Forecast Area FA

n refers to the total number of nodal loads for forecasting area FA

4. The new LDFs shall also be applied for the next hour $H+1$

$$\text{LDF\_new}_{b,D,H+1,FA} = \text{LDF\_new}_{b,D,H,FA}$$

Where:

$\text{LDF\_new}_{b,D,H+1,FA}$ refers to the load distribution factor of nodal load b for day type D and hour $H+1$ at Forecast Area FA

For example, if the timestamp of the latest available real-time snapshot is "2019-12-17 14:25", then its *reference day type* is 2 by default (12/17/2019 is on a Tuesday), while its *reference hour* is 14. The next immediate hour belongs to day type 2 and hour 15.

For example, if the timestamp of the latest available real-time snapshot is "2019-12-19 00:45", then its *reference day type* is 3 and reference hour is 24. The next immediate hour belongs to day type 4 and hour 1. The latest snapshot in this example has Hour 0 of 12/19/2019. This is translated as Hour 24 of 12/18/2019. 12/18/2019 falls on a Wednesday, hence, its default day type is 3.

Sample Updating of the Load Distribution Factor

In order to better understand the aforementioned processes in updating the load distribution factors of each nodal load, let us use the following example.

1. Let us assume that the latest time stamp t is 14:25 of 12/19/2019:

   a) The reference day type is 4
   b) The reference hour is 14

2. Let us also assume that the following loads reside in Forecast Area *FA*, each having a defined data source type, along with their MW load at timestamp t and their most recent LDF values for day type 4 and hour 14.

Table 3. Sample Nodal Load Profile and MW values at Timestamp t

Nodal Load	Data Source Type	MW Load @ t	Current LDF
Load_A	Real-Time	950	0.2000
Load_B	Real-Time	1425	0.3000
Load_C	Real-Time	1900	0.4000
Load_D	Estimated	--	0.1000

Note: The assumption here is that Load_D's base MW is being estimated since its snapshot data is persistently non-updating.

3. The Base MW of Load_A, Load_B, and Load_C shall be equal to their respective MW Load at timestamp *t*.

4. The Base MW of Load_D shall be obtained as follows.

   a) If the actual demand of the latest snapshot at 14:25 of 12/19/2019 at Forecast Area *FA* is 5000 MW, whereas the estimated loss percentage is 0.02 at day type 4 and hour 14, then:

$$\text{Est\_Net\_Load}_{t,FA} = \left(1 - \text{Est\_Loss}_{FA,D,H,}\right) \times \text{Actual\_Demand}_{t,FA}$$

$$\text{Est\_Net\_Load}_{t,FA} = (1-0.02) \times 5000 = 4900$$

   b) With this, we can now derive the Base MW of Load_D

$$\text{Base\_MW}_{Load\_D,4,14,FA} = 0.1000 \times 4900 = 490 \text{ MW}$$

5. Let us then assume that the smoothing factor is 0.8. With this, we can now derive the new LDFs using the established formula:

$$\text{LDF\_new}_{b,D,H,FA} = \left[\left(\frac{\text{Base\_MW}_{b,D,H,FA}}{\sum_{k=1}^{n} \text{Base\_MW}_{k,D,H,FA}}\right) \times \alpha\right] + \left[\left(\text{LDF\_old}_{b,D,H,FA}\right) \times (1-\alpha)\right]$$

For example, for Load_A:

$$\text{LDF\_new}_{Load\_A,4,14,FA} = \left[\left(\frac{950}{4765}\right) \times 0.8\right] + [(0.2000) \times (1 - 0.8)] = 0.19950$$

The following new LDFs shall be obtained for all nodal loads defined in Forecast Area *FA*:

Table 4. Sample Updated LDF Values for Day Type D and Hour H

Nodal Load	Data Source Type	Current LDF	New LDF
Load_A	Real-Time	0.2000	0.19950
Load_B	Real-Time	0.3000	0.29924
Load_C	Real-Time	0.4000	0.39899
Load_D	Estimated	0.1000	0.10227

6. The same LDFs shall be updated for the next immediate hour.

Manual Override

The *Market Operator* may provide overriding LDFs to specific nodal loads for a specific day and hour due to the following conditions:

a) the result of the LDF based on the default day type will not reflect the expected day type such as holidays and/or days with significant events; and/or
b) the result of the LDF is not based on the updated real-time data.

Should an overriding LDF value be defined for a specific day and hour, it shall be used regardless of the calculations used in the processes above.

Use of LDF in Nodal Forecast

The LDFs to be used in Section 6.2.6 of this Manual shall be based on the latest updated LDF at the day type and hour representing the projected *dispatch interval.* Note that the day type and hour shall be based on the start time of the projected *dispatch interval.*

For example, if the *dispatch interval* covers a start time of 19:55 and an end time of 20:00 of 12/04/2019, then its reference day type and reference hour shall be based on 19:55 of 12/04/2019. Thus, the day type shall be 3 (12/04/2019 is Wednesday), while the hour is 19. As such, in this example, the LDFs of day type 3 and hour 19 shall be used to project the nodal loads for dispatch interval 19:55-20:00 of 12/04/2019.