WESM Market Manual

Price Determination Methodology

Abstract
Provides the mechanism for determining the prices and settlements in the Philippine Wholesale Electricity Spot Market.

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The Price Determination Methodology Market Manual for the implementation of enhancements to WESM design and operations; Consolidated the following WESM Manuals in the PDM:

1. Procedure for Determining Ex-Post Nodal Energy Prices (EPNEP), Issue 2
2. Methodology for Determining Pricing Errors and Price Substitution Due to Congestion for Energy Transactions in the WESM (PSM), Issue 4
3. Administered Price Determination Methodology (APDM), Issue 5
4. Segregation of Line Rental Trading Amounts (SLRTA), Issue 1
5. Management Net Settlement Surplus, Issue 2
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## Reference Documents

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SECTION 1 INTRODUCTION

1.1 Background

1.1.1 The establishment of the Philippine Wholesale Electricity Spot Market (WESM) is mandated by Republic Act No. 9136, otherwise known as the Electric Power Industry Reform Act of 2001 (EPIRA).

1.1.2 Pursuant to the mandate of the EPIRA, the Department of Energy (DOE) jointly with the electric power industry participants formulated the WESM Rules, which, among others, provide the mechanism for determining the prices of electricity in the market not covered by bilateral contracts.

1.1.3 This Price Determination Methodology Manual provides the specific details of such mechanism. The price determination methodology contained in the WESM Rules is required by the EPIRA to be approved by the Energy Regulatory Commission (ERC).\(^1\)

1.2 Purpose

The price determination methodology and settlement formula in this Market Manual shall ensure that the following market design principles and characteristics of the WESM are achieved:

a. Gross pool, where each Scheduled Generation Company offers its maximum available capacity, Non-Scheduled Generation Company submits a standing nomination of loading levels, and Generation Company, with must dispatch generating units and priority dispatch generating units, submits projected outputs, for central scheduling and dispatch to ensure system security and a level playing field among generators;\(^2\)

b. Net settlement, where bilateral contract quantities are settled outside the WESM;\(^3\)

c. Co-optimized energy and reserves, where the provision of energy and reserves are jointly optimized in the market dispatch optimization model;\(^4\)

d. Self-commitment, where Trading Participants manage their technical operations, unit commitment decisions and other market risks through submission of bids and offers to the WESM;\(^5\)

e. Prices are governed, as far as practicable, by commercial and market forces;\(^6\)

f. Full nodal or locational marginal pricing regime in energy for both generator market trading nodes and customer market trading nodes, to provide economic

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\(^1\) WESM Rules Clause 3.2  
\(^2\) WESM Rules Clauses 1.2.5 and 3.5.5  
\(^3\) WESM Rules Clause 3.13  
\(^4\) WESM Rules Clause 3.6  
\(^5\) WESM Rules Clause 3.5  
\(^6\) WESM Rules Clause 1.2.5
signals that properly account the economic impact of losses and constraints that resulted from the operation of the electricity market;\(^7\)

g. Zonal pricing for reserves;\(^8\)

h. Trading Participants are provided with regularly updated information on projected prices, dispatch and other market outcomes to ensure they can make informed commercial and technical decisions;\(^9\) and

i. Other principles that are contained in the issuances of the DOE insofar as these principles are consistent with the objectives of applicable laws.

1.3 Scope

This Market Manual provides the following:

a. Methodology by which energy and reserves shall be priced and settled in accordance with the market design principles as issued by the DOE;\(^10\)

b. Methodology by which energy and reserves in the WESM shall be priced,\(^11\) including the determination of prices when there is extreme price separation due to network congestion,\(^12\) and determination of administered prices during market suspension and market intervention;\(^13\)

c. Methodology by which energy and reserves shall be settled in the WESM, including the cost recovery for reserves, the determination of additional compensation, as applicable, and the determination and allocation of net settlement surplus;\(^14\) and

d. Computational formula that will enable the WESM participants to verify the correctness of the charges being imposed.

SECTION 2 DEFINITIONS, REFERENCES AND INTERPRETATION

2.1 Definitions

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

2.1.2 The following words and phrases as used in this Market Manual shall have the following meaning –

\(^7\) WESM Rules Clauses 3.2.2 and 3.6.1
\(^8\) WESM Rules Clause 3.6.1
\(^9\) WESM Rules Clause 1.2.5
\(^11\) WESM Rules Clause 3.10
\(^12\) WESM Rules Clause 3.12.7
\(^13\) WESM Rules Clause 6.2.3
\(^14\) WESM Rules Clause 3.13
Price Determination Methodology

a. **Algorithm.** The process/processes applied by the *market dispatch optimization model* in computing the *dispatch schedules* and prices.

b. **Constrained Solution.** A solution produced by the *market dispatch optimization model* considering all constraints based on the price determination methodology.

c. **Constrained-on Generators.** Generation units that were scheduled to run pursuant to the original market solution but would not have been cleared or cleared at a lower quantity based on the *unconstrained solution*.

d. **Economic gain.** The total benefit that will be received by the producers and consumers of electricity in the *security-constrained economic dispatch* optimization.

e. **Energy Administered Price.** The price used in lieu of the *nodal energy dispatch price* during dispatch intervals under market suspension or market intervention.

f. **Final Nodal Energy Dispatch Price.** The final nodal price for energy after the application of price substitution due to network congestion or when conditions for price mitigation exists, or administered prices, as applicable.

g. **Locational Marginal Pricing.** The mechanism by which the *nodal energy dispatch price* is determined.

h. **Network Congestion.** The congestion at a line or transformer that is connected in a meshed network.

i. **Network Data.** The electrical parameters used to represent the *transmission* and *sub-transmission systems* in the *market network model*.

j. **Reserve Administered Price.** The price used in lieu of the *reserve prices* during dispatch intervals under market suspension or market intervention.

k. **Reserve Requirement.** The MW level to be met for the various categories of reserves.

l. **Security-constrained economic dispatch.** The process of apportioning the total load on a system between the various generating plants to achieve the greatest economy of operation and taking account of the limitations of the power system.

m. **Security limits.** The limits imposed by the System Operator on generation and transmission equipment to maintain system security and reliability.

n. **Self-scheduled energy.** Refers to projected outputs of must dispatch and priority dispatch generating units, and nomination of loading levels of non-scheduled generating units.

o. **Snapshot Quantity.** The actual instantaneous injection, withdrawal, or line flow of power, in MW, at the end of a *dispatch interval.*
p. **System marginal price.** The shadow price for which energy is priced.

q. **Transmission Loss Factor.** The scaling factors applied on the nodal energy dispatch prices to account for the network loss associated with the delivery or consumption of energy at different locations in the system.

r. **Unconstrained Solution.** A co-optimized solution of the market dispatch optimization model that does not take into consideration the thermal limits of lines and transformers.

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

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### SECTION 3 RESPONSIBILITIES

#### 3.1 Market Operator

The Market Operator shall be responsible for the development, validation, maintenance, publication in the Market Information Website, and revision of this Market Manual in coordination with WESM Participants.

#### 3.2 System Operator

The System Operator shall provide the necessary information and references for the implementation and subsequent revisions and validation of this Market Manual.

#### 3.3 Trading Participants

The Trading Participants shall provide the necessary information and references for the implementation and subsequent revisions and validation of this Market Manual.

#### 3.4 Network Service Providers

The Network Service Providers shall provide the necessary information for the implementation of this Market Manual.
SECTION 4 DISPATCH AND PRICING ALGORITHM

4.1 Scope

This section provides an overview of the dispatch and pricing algorithm for energy and reserves in the WESM. The detailed formulation of the algorithm is provided for in Appendix A of this Market Manual.

4.2 Market Dispatch Optimization Model

4.2.1 The WESM shall employ a gross pool dispatch model where all submitted generation offers, reserve offers, projected outputs, nomination of loading levels, and demand bids are scheduled based on the mathematical optimization algorithm of the market dispatch optimization model.

4.2.2 The market dispatch optimization model shall perform computations in determining the market clearing price based on the information it receives on system conditions and constraints from the System Operator; generation and reserve offers, nomination of loading levels, projected output and demand bids from Trading Participants, and load forecasts from the Market Operator and Trading Participants.

4.2.3 It shall process these information to come up with an optimum scheduling of energy and reserves that will maximize economic gains for the Trading Participants taking into consideration the physical limitations of the transmission network and of the facilities of the Trading Participants.

4.2.4 It shall utilize linear programming techniques to determine dispatch schedules and calculate nodal energy dispatch prices for all market trading nodes in the market network model and reserve prices for all reserve regions.

4.3 Required Inputs to the Market Dispatch Optimization Model

4.3.1 The market dispatch optimization model shall receive input data from three (3) sources, namely, the System Operator, the Trading Participants, and the Market Operator. The information provided are as required in the WESM Rules15.

4.3.2 System Operator and Network Service Provider Inputs:
   a. Network data;
   b. System snapshot;
   c. Outage schedules;
   d. Contingency list; and
   e. Over-riding constraints;
      • Security limits
         ➢ Generation limits
         ➢ Branch group limits

15 WESM Rules Clause 3.5
Must-run generation

- Non-security limits
  - Testing and commissioning

4.3.3 Where applicable, Trading Participant Inputs:
   a. Registration data;
   b. Generation offers;
   c. Demand bids;
   d. Reserve offers;
   e. Schedule of loading levels;
   f. Projected output; and
   g. Optional load forecast.

4.3.4 Market Operator Inputs:
   a. Market network model;
   b. Reserve requirements;
   c. Nodal load forecast; and
   d. Constraint violation coefficient.

4.4 Objective Function

4.4.1 The market dispatch optimization model shall maximize the economic gain derived from electricity trades in the market. This is defined to be the maximization of the value of dispatched load based on demand bids, less the costs of the following:

   a. Dispatched generation based on generation offers;
   b. Dispatched reserves based on reserve offers;
   c. Load curtailment; and
   d. Constraint violation based on constraint violation coefficients.\(^{16}\)

It is represented by the following formulation:

Maximize the economic gain from trade, where:

\[
\text{Economic Gain} = \sum_{i} \left\{ \sum_{b} \left[ \left( \text{DB}_{b,i} \right) \left( \text{PDB}_{b,i} \right) \right] - \sum_{k} \left[ \left( \text{G}_{k,i} \right) \left( \text{PG}_{k,i} \right) \right] - \sum_{r} \sum_{j} \left[ \left( \text{R}_{j,r,i} \right) \left( \text{PR}_{j,r,i} \right) \right] \right. \\
- \sum_{c} \left[ \left( \text{CQ}_{c,i} \right) \left( \text{CP}_{c,i} \right) \right] - \sum \text{CVP} \right\}
\]

Where:

\(i\) refers to a specific dispatch interval

\(^{16}\) WESM Rules Clause 3.6.1.3
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1.8.11 refers to the number of dispatch intervals involved in the solution

\( E_D \) refers to the number of demand bid blocks in a dispatch interval \( i \)

\( E_G \) refers to the number of generation offer blocks in a dispatch interval \( i \)

\( E_R \) refers to the number of reserve offer blocks in a dispatch interval \( i \)

\( N_R \) refers to the number of reserve categories

\( DB_{b,i} \) refers to the demand bid block quantity \( b \) at dispatch interval \( i \)

\( PDB_{b,i} \) refers to the demand bid block price \( b \) at dispatch interval \( i \)

\( G_{k,i} \) refers to the generation offer block quantity \( k \) at dispatch interval \( i \)

\( PG_{k,i} \) refers to the generation offer block price \( k \) at dispatch interval \( i \)

\( R_{j,r,i} \) refers to the reserve offer block quantity \( j \) for reserve category \( r \) at dispatch interval \( i \)

\( PR_{j,r,i} \) refers to the reserve offer block price \( j \) for reserve category \( r \) at dispatch interval \( i \)

\( CQ_{c,i} \) refers to the curtailment quantity \( c \) at dispatch interval \( i \)

\( CP_{c,i} \) refers to the curtailment price \( c \) at dispatch interval \( i \)

\( CVP \) refers to constraint violation penalties

4.4.2 The objective function can be comprised of a solution for only one dispatch interval, or a set of dispatch intervals.

4.4.3 Market projections shall employ a security-constrained economic dispatch, wherein the economic gain from trade for each execution of a market projection is maximized for the entire set of dispatch intervals in the covered study period of that market projection.

4.4.4 The real-time dispatch shall employ a security-constrained economic dispatch and shall be solved per dispatch interval.

4.4.5 If there are no prices and schedules determined during the real-time dispatch, then the results of the corresponding hour ahead projection shall be used for that dispatch interval\(^{17}\).

4.5 Dispatch Constraints

The objective function in Section 4.4 of this Market Manual shall be subject to the following constraints:

a. System Constraints

i. System power balance, including power balance during islanding operation

ii. Reserve region requirements, including ancillary services cascading

iii. Reserve provider capacity cap

iv. AC power flow, including the network loss model and power flow limits

v. HVDC flow limit

vi. Nodal energy balance constraint

\(^{17}\) WESM Rules Clause 3.4.1.2
b. Resource Constraints

i. Generator resource energy constraint
ii. Load resource energy constraint
iii. Reserve resource constraint
   • Reserve capacity limit
   • Combined reserve ramping limit
iv. Combined energy and reserve capacity limit
v. Combined energy and reserve ramping
vi. Constraints that pertain to the operational modes of generators, loads or similar facilities

c. Generic Constraints

i. Over-riding Constraints
   • Security Limit
   • Transmission Limit
ii. Outage schedule
iii. Contingency list

4.6 Tie-Breaking of Equivalent Offers\(^\text{18}\)

4.6.1 In cases of two or more optimal solutions resulting from equivalent offers, the market dispatch optimization model shall pro-rate the schedule among the affected Trading Participants while observing equipment limitations based on the generation offer/demand bid block quantity.

4.6.2 In case of a tie between a demand bid and a generator offer, the generation offer shall be maximized to meet the load requirement.

4.7 Priority-Scheduling

When restricting dispatch targets under WESM Rules Clause 3.6.1.7, the market dispatch optimization model shall consider the following hierarchy when a combination of the groups are to be restricted:\(^\text{19}\)

a. Market offers of scheduled generating units;
b. Non-scheduled generating units;
c. Priority dispatch generating units; and
d. Must dispatch generating units.

\(^{18}\) See Appendix B for the sample application of the tie-breaking rules.

\(^{19}\) WESM Rules Clauses 3.6.1.8
4.8 Constraint Violation Coefficients

4.8.1 The constraint violation coefficients shall correspond to soft constraints in the market dispatch optimization model and are associated with constraint violation prices.\(^20\)

4.8.2 Some constraints in the market dispatch optimization model shall be set up with one or more non-negative violation variables and associated constraint violation coefficients to ensure that the market dispatch optimization model shall always find a solution which satisfies all constraints, if such a solution exists. It shall also ensure that, if constraints are violated, the violation shall occur in an appropriate priority order that takes account of the system security and reliability of the power system and the feasibility of the resulting dispatch schedule.

4.8.3 The following are the types of constraint violation coefficients incorporated in the market dispatch optimization model:

a. Deficit reserve for each reserve category;

b. Nodal value of lost load;

c. N-x contingency thermal constraint;

d. Under-generation;

e. Over-generation;

f. Base case thermal constraint; and

g. Self-scheduled generation constraint.

4.8.4 The constraint violation coefficients shall be set for:

a. Market projections and dispatch scheduling, and

b. Market pricing reruns when the market projections and dispatch schedules have resulted in a non-zero violation variable.

4.8.5 The constraint violation coefficients shall be set for market pricing re-runs to ensure that the dispatch of all network elements, loads, and generating units produced by the market optimization algorithm are approximately the same as the original market dispatch. It shall also be set to ensure that the prices produced by the market optimization algorithm shall be appropriate in all the circumstances for settlement purposes, taking into consideration the processes provided for in Section 5 of this Market Manual.

4.9 Outputs from the Market Dispatch Optimization Model

The optimization process shall produce the following outputs for the market projections and real-time dispatch:

a. Cost of the solution or economic gain;

b. Transmission line flows;

\(^20\) WESM Rules Clauses 3.6.1.3 and 3.6.2
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c. Losses by each equipment and in aggregate;  
d. Dispatch schedules  
   i. Energy; and  
   ii. Reserve;  
e. Market prices;  
   i. System marginal price;  
   ii. Nodal energy dispatch prices;  
   iii. Reserve prices for each reserve category and reserve region; and  
f. Non-zero constraint violation variables.  

4.10 Locational Marginal Pricing  

4.10.1 Locational marginal pricing shall reflect the benefit of supplying electricity or the cost of consuming electricity at that location under the specific system conditions that were considered in the dispatch scheduling process. Locational marginal prices shall consider the marginal price of generation, transmission losses and congestion, and is represented as follows:

\[
LMP_j = \text{System Marginal Price} + \text{Marginal Cost of Losses} + \text{Marginal Cost of Congestion}
\]

The locational marginal pricing formula is as follows:

\[
LMP_j = \lambda + \left(\frac{1}{TLF_j} - 1\right) \lambda + \sum \mu_o \cdot a_{j, o}
\]

Where:

- \(LMP_j\) refers to the locational marginal price at location \(j\)  
- \(\lambda\) refers to the system marginal price  
- \(TLF_j\) refers to the transmission loss factor at location \(j\)  
- \(u_o\) refers to the price corresponding to \(o^{th}\) transmission constraint  
- \(a_{j, o}\) refers to the sensitivity factor relating the contribution of generation at location \(j\) to the energy flow related to constraint \(o\)

4.10.2 Transmission loss factors shall be dynamically computed within the market dispatch optimization model to fully account for the dynamic change in the losses due to a change in load at the various nodes.

The transmission loss factor formula at location \(j\) is as follows:

\[
TLF_j = \frac{1}{1 - \frac{\partial P_{\text{Loss}}}{\partial P_j}}
\]
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Where:

\[ TLF_j \]
refers to the transmission loss factor applied at location \( j \)

\[ \frac{\partial P_{Loss}}{\partial P_j} \]
refers to the incremental change in loss due to the incremental change of power at location \( j \)

4.10.3 Congestion cost shall reflect the restriction imposed on energy dispatches due to the thermal limitations of affected transmission equipment. When a market trading node is affected by one or more congestions in the system, specific congestion costs shall be measured for such market trading node based on its sensitivity relative to the constrained equipment multiplied by the price corresponding to the transmission constraint. The sensitivity shall be measured based on power flow, wherein a market trading node’s injection/withdrawal is evaluated if it affects the loading of the constrained equipment.

The congestion cost formula is as follows:

\[
\text{Congestion Cost} = \sum [\mu_o * a_{j,o}]
\]

Where:

\( \mu_o \)
refers to the price corresponding to \( o^{th} \) transmission constraint

\( a_{j,o} \)
refers to the sensitivity factor relating the contribution of generation at location \( j \) to the energy flow related to constraint \( o \)

4.11 Reserves

4.11.1 Reserve and energy dispatch schedules shall be determined in a co-optimized manner in the market dispatch optimization model.\(^{21}\)

4.11.2 The Market Operator, in consultation with the System Operator, shall determine an appropriate set of reserve categories to be traded in the spot market in conformance to the relevant provisions of the Grid Code\(^{22}\).

4.11.3 The reserve categories shall correspond to mutually distinct responses to an increase or decrease in system frequency with different response timeframes. These shall be technology neutral to allow responses from any facility certified to be capable of providing the requisite response, and shall define responses for frequency regulation and contingency reserves.

\(^{21}\) WESM Rules Clause 3.6
\(^{22}\) WESM Rules Clause 3.3.4.2
4.11.4 The *Market Operator*, in consultation with the *System Operator*, shall determine an appropriate set of *reserve regions* that will be used for the purpose of setting *reserve requirements*, and determining *reserve prices* and *reserve cost recovery charges*\(^{23}\).

4.11.5 The *reserve regions* shall initially consist of the Luzon, Visayas, and Mindanao grids.

4.11.6 The *reserve price* for each *reserve region* and *reserve category* shall be determined as the shadow price on the relevant *reserve requirement constraint* in the dispatch optimization for that *dispatch interval*\(^{24}\).

4.12 **Application of WESM Prices**

4.12.1 In general, the nodal prices resulting from the *real-time dispatch market run* as determined in Section 4.4.4, and, as applicable, Section 4.4.5, shall be used as *final nodal energy prices* or *reserve dispatch prices* in the calculation of *settlements* except if there are non-zero constraint violation variable values or pricing error notices:

   a. If there are one or more non-zero constraint violation variable values, then *automatic pricing re-run prices* in accordance with Section 5.2 shall apply; and
   
   b. If there are pricing errors, prices from market pricing re-runs under Section 5.3 shall apply.

4.12.2 If conditions for extreme price separation due to *network congestion* exist, prices as determined in Section 4.12.1 shall be replaced in accordance with Section 6.

4.12.3 If conditions for price mitigation exist, prices as determined in Sections 4.12.1 and 4.12.2 shall be replaced in accordance with the methodology as approved by the *ERC*\(^{25}\).

4.12.4 Notwithstanding Sections 4.12.1, 4.12.2 and 4.12.3, if the *dispatch interval* is under *market intervention* or *market suspension*, administered *prices* as determined under Section 7 shall apply.

4.13 **Final Nodal Energy Dispatch Prices for Customer Zones**

4.13.1 If applicable, the *final nodal energy dispatch price of customers* that have been approved by the *ERC* to use zonal pricing is further determined as the *customer dispatch schedule*-weighted average of the *final nodal energy dispatch price*, as determined in accordance with Section 4.12, within a *customer pricing zone*, as provided in the following formula:

\(^{23}\) *WESM Rules* Clause 3.3.7.1
\(^{24}\) *WESM Rules* Clauses 3.6.1.4 and 3.10.7
\(^{25}\) *ERC Resolution No.20*, Series of 2014, dated 15 December 2014, entitled “A Resolution adopting and Establishing a Pre-emptive Mitigation Measure in the Wholesale Electricity Spot Market (WESM),” which may be amended from time to time.
\[ \text{FEDP}_{z,b,i} = \frac{\sum_{b \in B_z} (\text{FEDP}_{b,i} \times \text{EDS}_{b,i})}{\sum_{b \in B_z} \text{EDS}_{b,i}} \]

However, if:

\[ \sum_{b \in B_z} \text{EDS}_{b,i} = 0 \]

Then:

\[ \text{FEDP}_{z,b,i} = \frac{\sum_{b \in B_z} \text{FEDP}_{b,i}}{n_z} \]

Where:

- \( \text{FEDP}_{z,b,i} \) refers to the zonal final nodal energy price of customer resource \( b \) at dispatch interval \( i \) within customer pricing zone \( z \)
- \( \text{FEDP}_{b,i} \) refers to the final nodal energy dispatch price as determined under Section 4.12 for customer resource \( b \) at dispatch interval \( i \)
- \( \text{EDS}_{b,i} \) refers to the energy dispatch schedule for customer resource \( b \) at dispatch interval \( i \)
- \( B_z \) set of all customer resources within customer pricing zone \( z \)
- \( n_z \) refers to the number of customer resources within customer pricing zone \( z \)

## SECTION 5  MARKET PRICING RE-RUNS

### 5.1 Scope

5.1.1 This section provides the automatic pricing re-run, which shall be performed automatically by the market system software of the Market Operator should the market dispatch optimization model result in one or more non-zero constraint violation variable values.\(^{26}\)

5.1.2 This section also provides the market pricing re-run, which shall be performed by the Market Operator upon issuance of a pricing error notice, notwithstanding the application of an automatic pricing re-run.\(^{27}\)

\(^{26}\) WESM Rules Clause 3.6.7

\(^{27}\) WESM Rules Clause 3.10.5
5.2 Automatic Pricing Re-Run

5.2.1 Automatic pricing reruns for market projections and real-time dispatch shall ensure that the energy and reserve prices reflect the following:

a. marginal costs of supplying energy at each node;

b. marginal costs of supplying reserve;

c. shortage pricing when there is a shortage of supply at a node or regional level, as determined in accordance with Section 5.4; and

d. excess pricing when there is an excess of supply at a node or regional level, as determined in accordance with Section 5.4.

5.2.2 The automatic pricing re-run of the market dispatch optimization model shall determine the prices for energy and reserves with relaxed constraints and shall have approximately the same dispatch schedules.

5.2.3 During the automatic pricing re-run, the soft constraint that was violated shall be relaxed corresponding to the resulting non-zero violation variable, including a very small value (delta) to allow the market dispatch optimization model to find a feasible price.

5.2.4 In case of over-generation and under-generation, the soft constraint shall be relaxed by a value (delta) to allow the market dispatch optimization model to find a feasible price. When the results of the market dispatch optimization model reflect a violation greater than delta, then the automatic pricing re-run shall reflect the shortage price for under-generation and excess pricing for over-generation.

5.2.5 The delta shall be set as small as possible for each constraint violation coefficient so that the automatic pricing re-run reflects the most accurate price considering the original dispatch schedules.

5.2.6 The following table shows each type of constraints with their corresponding constraint relaxation formulas during pricing re-runs:

<table>
<thead>
<tr>
<th>Soft Constraint</th>
<th>Violation</th>
<th>Constraint Relaxation during Pricing Re-Run</th>
<th>Re-run Price</th>
</tr>
</thead>
<tbody>
<tr>
<td>Thermal Base Case</td>
<td>x</td>
<td>x + delta</td>
<td>EDP AND RP</td>
</tr>
<tr>
<td>Transmission Group</td>
<td>x</td>
<td>x + delta</td>
<td>EDP AND RP</td>
</tr>
<tr>
<td>Self-Scheduled Generation Constraint</td>
<td>x</td>
<td>x + delta</td>
<td>EDP AND RP</td>
</tr>
<tr>
<td>System Energy Balance</td>
<td>x</td>
<td>delta</td>
<td>Excess Price if Over-generation</td>
</tr>
</tbody>
</table>

28 EDP refers to nodal energy dispatch price; and RP refers to reserve price
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<table>
<thead>
<tr>
<th>Soft Constraint</th>
<th>Violation</th>
<th>Constraint Relaxation during Pricing Re-Run</th>
<th>Re-run Price²⁸</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nodal Value of Lost Load or Nodal Energy Balance</td>
<td>x</td>
<td>x + delta</td>
<td>EDP AND RP</td>
</tr>
<tr>
<td>Thermal Contingency</td>
<td>x</td>
<td>x + delta</td>
<td>EDP AND RP</td>
</tr>
<tr>
<td>Reserve Requirement</td>
<td>x</td>
<td>x + delta</td>
<td>EDP AND RP</td>
</tr>
</tbody>
</table>

5.2.7 The market projections and real-time dispatch market runs shall be reflective of prices determined from automatic pricing re-runs.

5.3 Market Pricing Re-Run to address Pricing Errors

5.3.1 Notwithstanding the application of automatic pricing re-run, the Market Operator shall issue a pricing error notice and perform a market pricing re-run, in the event where the calculated prices are believed to be in error due to erroneous, inconsistent, or inappropriate input data.²⁹

5.3.2 The Market Operator shall perform the market pricing re-run using appropriately revised inputs for the relevant dispatch market run, taking into consideration the applicable solutions for the various causes of erroneous, inconsistent and inappropriate input data.

5.4 Shortage and Excess Prices

5.4.1 In the event of under-generation, the shortage price shall be determined as the offer price cap.

5.4.2 In the event of over-generation, the excess price shall be determined as the offer price floor.

SECTION 6 PRICE SUBSTITUTION METHODOLOGY DUE TO CONGESTION

6.1 Scope

This section provides the price substitution methodology, which shall be implemented by the Market Operator in addressing the undesirable market pricing situations that arise from the effects of network congestion in the power system, particularly during the occurrence of extreme nodal price separation.³⁰

²⁹ WESM Rules Clause 3.10.5
³⁰ WESM Rules Clause 3.12.7
6.2 Criteria for Determining Extreme Nodal Price Separation Due To Network Congestion

6.2.1 If a dispatch interval is reflective of extreme nodal price separation due to network congestion, then prices shall be substituted for the affected generators and customers.

6.2.2 The following constraints shall not be considered as network congestion:

a. Constraint indicated in the market run is caused by erroneous input data;
b. Localized constraint, such as but not limited to, constraint on a load-end transformer, which is the source of the load connected to it or of the step-up transformer in a generating plant; and
c. Constraint on a radially-connected line.

6.2.3 A dispatch interval shall be identified to be reflective of extreme nodal price separation through the use of a trigger factor, which is formulated as follows:

\[
\text{Price Trigger Factor}_i = \sqrt{\frac{\sum_{j \in J} (\text{EDS}_{j, i} \cdot (\text{EDP}_{j, i} - \text{NWAP}_i)^2)}{\sum_{j \in J} (\text{EDS}_{j, i})}} \frac{\text{NWAP}_i}{\text{NWAP}_i}
\]

Where:

- \( J \) refers to the set of all resources
- \( \text{EDS}_{j, i} \) refers to the energy dispatch schedule of resource \( j \) at dispatch interval \( i \)
- \( \text{EDP}_{j, i} \) refers to the nodal energy dispatch price of resource \( j \) at dispatch interval \( i \)
- \( \text{NWAP}_i \) refers to the weighted average price of all resources and computed as:

\[
\text{NWAP}_i = \frac{\sum_{j \in J} (\text{EDP}_{j, i} \cdot \text{EDS}_{j, i})}{\sum_{j \in J} (\text{EDS}_{j, i})}
\]

6.2.4 The price substitution methodology set forth in this section shall apply to a dispatch interval when the trigger factor reaches the threshold, which shall be set at 0.2, subject to annual review. For this purpose, PEMC shall conduct an assessment of the application of the price trigger and the results of the assessment shall be submitted to the WESM Technical Committee for evaluation and for determination as to whether a change in the value of the price trigger is warranted.
6.3 **Price Substitution Methodology for Generator Energy Prices**

6.3.1 An *unconstrained solution* shall be used for determining the generator energy prices.

6.3.2 *Constrained-on generators* shall be paid at their offer price corresponding to their last MW offer block that was scheduled.

6.3.3 All other generators shall be paid at the *unconstrained solution’s* marginal price.

6.4 **Price Substitution Methodology for Customer Energy Prices**

6.4.1 All *loads* shall have the same price and shall be calculated as follows:

\[
SEDP_{b, i} = \frac{\sum_{k \in K} (SEDP_{k, i} \times EDS_{k, i})}{\sum_{b \in B} (EDS_{b, i})}
\]

Where:
- \(SEDP_{b, i}\) refers to the substitute *nodal energy dispatch price of customer* \(b\) *in the affected pricing region at dispatch interval* \(i\)
- \(SEDP_{k, i}\) refers to the substitute *nodal energy dispatch price of generator* \(k\) *at dispatch interval* \(i\)
- \(EDS_{k, i}\) refers to the *energy dispatch schedule of generator* \(k\) *in the constrained solution at dispatch interval* \(i\)
- \(EDS_{b, i}\) refers to the *energy dispatch schedule of customer* \(b\) *at dispatch interval* \(i\)

6.4.2 In cases where the *HVDC* is on *outage* or there is no interconnection between the Luzon, Visayas, and Mindanao regions, Section 6.4.1 shall apply only to the region/s with congestion.

6.5 **Price Substitution Methodology for Reserve Prices**

6.5.1 Aside from normalizing the *energy* prices due to the congestion, the price substitution methodology shall also consider the impact of the extreme nodal price separation on the resulting *reserve prices*.

6.5.2 In cases where price substitution methodology is applied, the *reserve price* for a certain *reserve category in a reserve region* shall be calculated as the sum of the *constrained solution’s marginal reserve offer price* and the *opportunity cost* calculated based on the *unconstrained solution*. It shall be calculated as follows:

\[
SRP_{j, r, a, i} = MROP_{CONS-r, a, i} + \text{OppCost}_{UNCD-r, a, i}
\]

Where:
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**SECTION 7  ADMINISTERED PRICES**

**7.1 Scope**

This section provides the administered price determination methodology, which shall be implemented by the Market Operator to impose administered prices on dispatch intervals under market suspension or market intervention.\(^{31}\)

**7.1.2** The administered price shall be established by the Market Operator in accordance with the following guiding principles:

a. The administered price shall be fair and reasonable to both the suppliers and consumers of electricity.

b. Administered prices shall be determined and shall replace market prices for energy, i.e. energy administered prices shall replace the nodal energy dispatch prices, and reserves, i.e. reserve administered prices shall replace the reserve prices.

c. The process for determining the administered price shall be transparent to the Trading Participants and administratively simple to implement.

d. The process for determining the administered price shall be based on the market information available prior to market intervention or market suspension.

e. The administered price shall be applied in the region where the market suspension or market intervention is declared. For this purpose, the regions are Luzon, Visayas and Mindanao.

f. Where market suspension or market intervention is declared in an island grid (“grid islanding”), the administered prices shall be applied only to the resources in the island grid where the market suspension or market intervention was declared.

g. The administered price will apply only to transactions above the declared bilateral contract quantities.

**7.2 Generator Energy Administered Price**

For each generator resource, the energy administered price shall be computed using the snapshot quantity and either the nodal energy dispatch prices or energy administered prices of the four (4) most recent similar trading days and similar dispatch intervals depending on whether or not these have been administered.

\(^{31}\) WESM Rules Clause 6.2.3
7.2.2 Similar trading days refer to each day of the week (i.e., Sunday, Monday, Tuesday, Wednesday, Thursday, Friday, Saturday) while similar dispatch intervals refer to the same period within the same settlement interval.

7.2.3 In case the snapshot quantity for a generator resource at a similar trading day and similar dispatch interval is negative, the snapshot quantity for that similar trading day and similar dispatch interval shall be set to zero during the calculation of the energy administered price for that generator resource.

7.2.4 In case one (1) or more of the four (4) most recent similar trading days and similar dispatch intervals have not been administered, the energy administered price for each generator resource k shall be computed as follows:

a. Snapshot quantity-weighted average of the nodal energy dispatch prices of the similar trading days and similar dispatch intervals that have not been administered as set out in the following formula:

\[
EAP_{k,D,i} = \frac{\sum_{d=D-n}^{D-1} (FEDP_{k,d,i} \times SQ_{k,d,i})}{\sum_{d=D-n}^{D-1} SQ_{k,d,i}}
\]

Where:

- \(EAP_{k,D,i}\) refers to the energy administered price for generator resource \(k\) at dispatch interval \(i\) within trading day \(D\)
- \(FEDP_{k,d,i}\) refers to the final nodal energy dispatch price for generator resource \(k\) for dispatch interval \(i\) within trading day \(d\)
- \(SQ_{k,d,i}\) refers to the snapshot quantity for generator resource \(k\) at dispatch interval \(i\) within trading day \(d\)
- \(D\) refers to the current trading day
- \(D - n\) refers to the \(n\)th most recent similar trading day of \(D\)
- \(n\) refers to the number of similar trading days and similar dispatch intervals that have not been administered from the four (4) most recent similar trading days and similar dispatch intervals

b. However, if the generator resource had no snapshot quantity for the previous similar trading days and similar dispatch intervals, the energy administered price for that generator resource shall be determined by obtaining the simple average of the final nodal energy dispatch prices of the preceding similar trading days and similar dispatch intervals that have not been administered as set out in the following formula:

\[
EAP_{k,D,i} = \frac{\sum_{d=D-n}^{D-1} FEDP_{k,d,i}}{n}
\]

Where:
7.2.5 In case all of the four (4) most recent similar trading days and similar dispatch intervals have been administered, the energy administered price for each generator resource k is computed as follows:

a. **Snapshot quantity-weighted average of the energy administered prices** of the similar trading days and similar dispatch intervals as set out in the following formula:

\[
EAP_{k,D,i} = \frac{\sum_{d=D-n}^{D-1} (EAP_{k,d,i} \times SQ_{k,d,i})}{\sum_{d=D-n}^{D-1} SQ_{k,d,i}}
\]

Where:

- \(EAP_{k,D,i}\) refers to the energy administered price for generator resource k at dispatch interval i within trading day D
- \(EAP_{k,d,i}\) refers to the energy administered price for generator resource k for dispatch interval i within trading day d
- \(SQ_{k,d,i}\) refers to the snapshot quantity for generator resource k at dispatch interval i within trading day d
- D refers to the current trading day
- \(d = D - n\) refers to the \(n^{th}\) most recent similar trading day of D

b. However, if the generator resource had no snapshot quantity for the previous similar trading days and similar dispatch intervals, the energy administered price for that generator resource shall be determined by obtaining the simple average of the energy administered prices of the preceding similar trading days and similar dispatch intervals as set out in the following formula:

\[
EAP_{k,D,i} = \frac{\sum_{d=D-n}^{D-1} EAP_{k,d,i}}{4}
\]

Where:

- \(EAP_{k,D,i}\) refers to the energy administered price for generator resource k for dispatch interval i within trading day D
7.2.6 In case a generator resource does not have final nodal energy dispatch prices in the preceding four (4) most recent similar trading days and similar dispatch intervals, the energy administered price for that generator resource shall be calculated as follows:

\[
EAP_{k, D, i} = \frac{\sum_{k' \in K_i, k' \neq k} (EAP_{k', D, i} \cdot SQ_{k', D, i})}{\sum_{k' \in K_i, k' \neq k} SQ_{k', D, i}}
\]

Where:

- \(EAP_{k, D, i}\) refers to the energy administered price for generator resource \(k\) for dispatch interval \(i\) within trading day \(D\)
- \(EAP_{k', D, i}\) refers to the energy administered price for generator resource \(k'\) for dispatch interval \(i\) within trading day \(D\)
- \(SQ_{k', D, i}\) refers to the snapshot quantity for generator resource \(k'\) at dispatch interval \(i\) within trading day \(D\)
- \(D\) refers to the trading day with dispatch interval under market intervention or market suspension
- \(K_i\) refers to the set of generator resources with positive snapshot quantities at dispatch interval \(i\)
- \(k'\) refers to a generator resource with positive snapshot quantity at dispatch interval \(i\) except for generator resource \(k\)

7.3 Customer Energy Administered Price

7.3.1 The energy administered price for all customer resources shall be calculated as follows:

\[
EAP_{b, i} = \frac{\sum_{k \in K_i} (EAP_{k, i} \cdot SQ_{k, i})}{\sum_{b \in B} SQ_{b, i}}
\]

Where:

- \(EAP_{b, i}\) refers to the energy administered price for customer resource \(b\) for dispatch interval \(i\)
- \(EAP_{k, i}\) refers to the energy administered price for generator resource \(k\) at dispatch interval \(i\)
- \(SQ_{k, i}\) refers to the snapshot quantity for generator resource \(k\) at dispatch interval \(i\)
7.3.2 In case only one region is under market suspension or market intervention and the said region is importing power from the other region, the energy administered price for all customer resources within the region under market suspension or market intervention shall be calculated as follows:

\[
EAP_{b, i} = \frac{\sum_{K \in K_i} (EAP_{k, i} \cdot SQ_{k, i}) + (SQ_{ITC, i} \cdot GWAP_{NAR, i})}{\sum_{b \in B_i} SQ_{b, i}}
\]

Where:

- \( EAP_{b, i} \) refers to the energy administered price for customer resource \( b \) for dispatch interval \( i \)
- \( EAP_{k, i} \) refers to the energy administered price for generator resource \( k \) for dispatch interval \( i \)
- \( SQ_{k, i} \) refers to the snapshot quantity for generator resource \( k \) for dispatch interval \( i \)
- \( SQ_{ITC, i} \) refers to the snapshot quantity of the interconnection for dispatch interval \( i \)
- \( GWAP_{NAR, i} \) refers to the generator weighted average price in the non-administered region using energy dispatch schedule for dispatch interval \( i \)
- \( SQ_{b, i} \) refers to the snapshot quantity for customer resource \( b \) at dispatch interval \( i \)
- \( K_i \) refers to the set of generator resources in the region under market suspension or market intervention with positive energy dispatch schedule for dispatch interval \( i \)
- \( B_i \) refers to the set of all customer resources in the region under market suspension or market intervention at dispatch interval \( i \)

7.3.3 In case only one region is under market suspension or market intervention and the said region is exporting power to the other region, the energy administered price for all customer resources within the region under market suspension or market intervention shall be calculated as follows:

\[
EAP_{b, i} = \frac{\sum_{K \in K_i} (EAP_{k, i} \cdot SQ_{k, i}) - (SQ_{ITC, i} \cdot GWAEAP_i)}{\sum_{b \in B_i} SQ_{b, i}}
\]

Where:
EAP\textsubscript{b,i} refers to the energy administered price for customer resource \textit{b} for dispatch interval \textit{i}

EAP\textsubscript{k,i} refers to the energy administered price for generator resource \textit{k} for dispatch interval \textit{i}

SQ\textsubscript{k,i} refers to the snapshot quantity for generator resource \textit{k} at dispatch interval \textit{i}

SQ\textsubscript{ITC,i} refers to the snapshot quantity of the interconnection at dispatch interval \textit{i}

GWAEAP\textsubscript{i} refers to the generator weighted average energy administered price using snapshot quantity for dispatch interval \textit{i}

SQ\textsubscript{b,i} refers to the snapshot quantity (in MW) for customer resource \textit{b} for dispatch interval \textit{i}

\textit{K}\textsubscript{i} refers to the set of generator resources in the region under market suspension or market intervention with positive energy dispatch schedule for dispatch interval \textit{i}

\textit{B}\textsubscript{i} refers to the set of all customer resources in the region under market suspension or market intervention for dispatch interval \textit{i}

7.3.4 In case only one region is under market suspension or market intervention and the said region is exporting power to the other region and the nodal energy dispatch prices in the region that is not under market suspension or market intervention were determined in accordance with WESM Rules Clause 3.6, the nodal energy dispatch prices for the customer resources within the region that is not under market suspension or market intervention shall be adjusted by adding the following:

\[
\text{NARAPA}_{b-NAR,i} = \frac{\text{SQ}_{ITC,i} \cdot (\text{GWAP}_{NAR,i} - \text{GWAEAP}_i)}{\sum_{b\in\text{B-NAR}_i} \text{EDS}_{b-NAR,i}}
\]

Where:

\text{NARAPA}_{b-NAR,i} refers to the non-administered region administered price adjustment for a customer resource within the non-administered region for dispatch interval \textit{i}

\text{SQ}_{ITC,i} refers to the snapshot quantity of the interconnection for dispatch interval \textit{i}

\text{GWAP}_{NAR,i} refers to the generator weighted average price at the non-administered region using energy dispatch schedule for dispatch interval \textit{i}

\text{GWAEAP}_i refers to the generator weighted average energy administered price using snapshot quantity for dispatch interval \textit{i}

\text{EDS}_{b-NAR,i} refers to the energy dispatch schedule of customer resource \textit{b} within the non-administered region for dispatch interval \textit{i}

\text{B-NAR}_i refers to the set of all customer resources within the non-administered region for dispatch interval \textit{i}

\text{b-NAR} refers to a customer resource within the non-administered region
7.4 Generator Reserve Administered Price

7.4.1 In case one (1) or more of the four (4) most recent similar trading days and similar dispatch intervals have not been administered, the reserve administered price for each generator resource $k$ shall be computed as follows:

a. The reserve dispatch schedule-weighted average of the reserve prices for each reserve category of the four (4) most recent similar trading days and similar dispatch intervals that have not been administered, as set out in the following formula:

$$RAP_{k,r,D,i} = \frac{\sum_{d=D-1}^{D-n} (RDP_{k,r,d,i} \times RDS_{k,r,d,i})}{\sum_{d=D-1}^{D-n} RDS_{k,r,d,i}}$$

Where:

- $RAP_{k,r,D,i}$ refers to the reserve administered price for generator resource $k$ for reserve category $r$ at dispatch interval $i$ within trading day $D$
- $RDP_{k,r,d,i}$ refers to the reserve dispatch price for generator resource $k$ for reserve category $r$ at dispatch interval $i$ within trading day $d$
- $RDS_{k,r,d,i}$ refers to the reserve dispatch schedule for generator resource $k$ for reserve category $r$ at dispatch interval $i$ within trading day $d$
- $D$ refers to the trading day with dispatch interval under market intervention or market suspension
- $d = D - n$ refers to the $n^{th}$ most recent non-administered similar trading day and similar dispatch interval
- $n$ refers to the number of similar trading days and dispatch intervals that have not been administered from the four (4) most recent similar trading days and dispatch intervals

b. If no reserve administered price can be determined for a generator resource because the generator resource had no reserve dispatch schedule for the previous four (4) similar trading days and similar dispatch intervals, the reserve administered price for that generator resource for that reserve category shall be computed by obtaining the simple average of the reserve prices for that reserve category for the reserve region which includes the generator resource of four (4) immediately preceding similar trading days and similar dispatch intervals that have not been administered. This is as set out in the following formula:

$$RAP_{k,r,D,i} = \frac{\sum_{d=D-1}^{D-n} RDP_{k,r,d,i}}{n}$$

Where:

- $RAP_{k,r,D,i}$ refers to the reserve administered price for reserve category $r$ for the reserve region which includes generator resource $k$ for dispatch interval $i$ within trading day $D$
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**RDP_{k,r,d,i}** refers to the reserve price for generator resource \( k \) for reserve category \( r \) for dispatch interval \( i \) within trading day \( D \).

\( D \) refers to the trading day with dispatch interval under market intervention or market suspension.

\( d = D - n \) refers to the \( n^{th} \) most recent non-administered similar trading day and similar dispatch interval.

\( n \) refers to the number of similar trading days and dispatch intervals that have not been administered from the four (4) most recent similar trading days and dispatch intervals.

### 7.4.2

In case all of the four (4) most recent similar trading days and similar dispatch intervals have been administered, the reserve administered price for each generator resource \( k \) shall be computed as follows:

a. Reserve dispatch schedule-weighted average of the reserve administered prices of the similar trading days and similar dispatch intervals as set out in the following formula:

\[
RAP_{k,D,i} = \frac{\sum_{d=D-1}^{D-n} (RAP_{k,d,i} \cdot RDS_{k,d,i})}{\sum_{d=D-1}^{D-n} RDS_{k,d,i}}
\]

Where:

- \( RAP_{k,D,i} \) refers to the reserve administered price for generator resource \( k \) at dispatch interval \( i \) within trading day \( D \).
- \( RAP_{k,d,i} \) refers to the reserve administered price for generator resource \( k \) for dispatch interval \( i \) within trading day \( d \).
- \( RDS_{k,d,i} \) refers to the reserve dispatch schedule for generator resource \( k \) at dispatch interval \( i \) within trading day \( d \).
- \( D \) refers to the current trading day.
- \( d = D - n \) refers to the \( n^{th} \) most recent similar trading day of \( D \).

b. However, if the generator resource had no reserve dispatch schedules for the previous similar trading days and similar dispatch intervals, the reserve administered price for that generator resource shall be determined by obtaining the simple average of the reserve administered prices of the preceding similar trading days and similar dispatch intervals as set out in the following formula:

\[
RAP_{k,D,i} = \frac{\sum_{d=D-1}^{D-n} RAP_{k,d,i}}{4}
\]

Where:

- \( RAP_{k,D,i} \) refers to the reserve administered price for generator resource \( k \) for dispatch interval \( i \) within trading day \( D \).
7.4.3 For each generator resource, the reserve dispatch schedule shall be set to the reserve schedules determined by the System Operator for the dispatch interval under market suspension or market intervention.

7.4.4 Similar trading days refer to each day of the week (i.e., Sunday, Monday, Tuesday, Wednesday, Thursday, Friday, Saturday) while similar dispatch intervals refer to the same period within the same settlement interval.

7.4.5 No reserve administered prices are calculated for customers within the region under market suspension or market intervention.

SECTION 8 BILLING AND SETTLEMENT

8.1 Scope

This section provides the following:

a. Formula used to determine the trading and settlement amounts for energy and reserves for each Trading Participant;\(^{32}\)

b. Formula to determine the costs of reserves to be recovered through the settlement amounts calculated;\(^{33}\) and

c. Provision of additional compensation for Trading Participants affected by market suspension or market intervention or are designated as must-run units.

8.2 Trading Amounts

8.2.1 Energy Trading Amount\(^{34}\)

d. The energy trading amount for a market trading node and settlement interval shall be determined using the final energy dispatch prices for that node, the gross energy settlement quantities, as determined under WESM Rules Clause 3.13.6, and bilateral contract quantities for that node in the dispatch intervals within the same settlement interval. It shall be calculated for generators and customers as follows:

i. Generators

\(^{32}\) WESM Rules Clause 3.13

\(^{33}\) WESM Rules Clause 3.3.5.2

\(^{34}\) WESM Rules Clause 3.13
\[ \text{ETA}_{k,h} = \sum_{i \in h} \left[ (\text{FEDP}_{k,i} \times \text{GESQ}_{k,i}) - \sum_{b \in B_i} (\text{FEDP}_{k,b,i} \times \text{BCQ}_{k,b,i}) \right] \]

Where:

- \( \text{ETA}_{k,h} \) refers to the energy trading amount of resource \( k \) at settlement interval \( h \)
- \( \text{FEDP}_{k,i} \) refers to the final energy dispatch price of generator resource \( k \) at dispatch interval \( i \) in settlement interval \( h \)
- \( \text{GESQ}_{k,i} \) refers to the gross energy settlement quantity for generator resource \( k \) at dispatch interval \( i \) in settlement interval \( h \)
- \( \text{FEDP}_{k,b,i} \) refers to the reference final nodal energy dispatch price for the bilateral contract quantity between generator resource \( k \) and load resource \( b \) at dispatch interval \( i \) in settlement interval \( h \) (default is generator FEDP)
- \( \text{BCQ}_{k,b,i} \) refers to the bilateral contract quantity for generator resource \( k \) to counterparty load resource \( b \) at dispatch interval \( i \) in settlement interval \( h \)
- \( B_i \) refers to the total number of resources that generator resource \( k \) has a contract with at dispatch interval \( i \)

ii. Customers/Buyers

\[ \text{ETA}_{b,h} = \sum_{i \in h} \left[ (\text{FEDP}_{b,i} \times \text{GESQ}_{b,i}) - \sum_{k \in K_i} (\text{FEDP}_{b,k,i} \times \text{BCQ}_{b,k,i}) \right] \]

Where:

- \( \text{ETA}_{b,h} \) refers to the energy trading amount of load resource \( b \) at settlement interval \( h \)
- \( \text{FEDP}_{b,i} \) refers to the final energy dispatch price of load resource \( b \) at dispatch interval \( i \) in settlement interval \( h \)
- \( \text{GESQ}_{b,i} \) refers to the gross energy settlement quantity for load resource \( b \) at dispatch interval \( i \) in settlement interval \( h \)
- \( \text{FEDP}_{b,k,i} \) refers to the reference final energy dispatch price for the bilateral contract quantity between generator resource \( k \) and load resource \( b \) at dispatch interval \( i \) in settlement interval \( h \) (default is generator FEDP)
- \( \text{BCQ}_{b,k,i} \) refers to the bilateral contract quantity for load resource \( b \) to counterparty generator resource \( k \) at dispatch interval \( i \) in settlement interval \( h \)
- \( K_i \) refers to the total number of resources that customer resource \( b \) has a contract with at dispatch interval \( i \) in settlement interval \( h \)
8.2.2 Reserve Trading Amount\textsuperscript{35}

a. The reserve quantity for any market trading node in any dispatch interval shall be determined by the Market Operator as the reserve dispatch schedule less reserve contracted quantities.

\[ RQ_{j, r, a, i} = (RDS_{j, r, a, i} - RBCQ_{j, r, a, i}) \]

Where:

- \( RQ_{j, r, a, i} \) refers to the reserve quantity of resource \( j \) for reserve category \( r \) and reserve region \( a \) at dispatch interval \( i \)
- \( RDS_{j, r, a, i} \) refers to the reserve dispatch schedule of resource \( j \) for reserve category \( r \) and reserve region \( a \) at dispatch interval \( i \)
- \( RBCQ_{j, r, a, i} \) refers to the bilateral contract quantity for resource \( j \) for reserve category \( r \) and reserve region \( a \) at dispatch interval \( i \)

b. The reserve trading amount for each Trading Participant who supplies reserve to a particular reserve region in a settlement interval shall be determined from the reserve dispatch prices for that reserve region multiplied by the reserve quantities for that Trading Participant in that reserve region for the respective dispatch intervals in that settlement interval.

\[ RTA_{j, r, a, h} = \frac{1}{n} \sum_{i \in h} (RDP_{j, r, a, i} \times RQ_{j, r, a, i}) \]

Where:

- \( RTA_{j, r, a, h} \) refers to the reserve trading amount of resource \( j \) for reserve category \( r \) and reserve region \( a \) at settlement interval \( h \)
- \( RDP_{j, r, a, i} \) refers to the reserve dispatch price of resource \( j \) for reserve category \( r \) and reserve region \( a \) at dispatch interval \( i \) in settlement interval \( h \)
- \( RQ_{j, r, a, i} \) refers to the reserve quantity of resource \( j \) for reserve category \( r \) and reserve region \( a \) at dispatch interval \( i \) in settlement interval \( h \)
- \( n \) refers to the number of dispatch intervals within a settlement interval

8.2.3 Reserve Cost Recovery

a. Cost Recovery for Regulation Service

The reserve cost attributed to the regulation service shall be recovered from all resources (generators or loads) by pro-rating the regulation reserve cost based on their respective gross energy settlement quantities, as determined under WESM Rules Clause 3.13.6, using the formula represented as:

\textsuperscript{35} WESM Rules Clause 3.13
Price Determination Methodology

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b. Cost Recovery for Contingency Service

i. The reserve costs for raise contingency service shall be allocated among generators using the following formula:  

\[
\text{CRCost}_{k, r, a, h} = \sum_{i \in h} \left[ \frac{\text{RTA}_{r, a, i}}{\sum_{j \in J} \text{GESQ}_{j, a, i}} \times \text{GESQ}_{j, a, i} \right]
\]

Where:

\[
\text{CRCost}_{k, r, a, h}
\]

refers to the reserve cost to be paid by generator \(k\) in reserve region \(a\) for reserve category \(r\) at settlement interval \(h\)

\[
\text{RTA}_{r, a, i}
\]

refers to contingency reserve trading amount in reserve region \(a\) for reserve category \(r\) at dispatch interval \(i\) within settlement interval \(h\)

\[
\text{GESQ}_{j, a, i}
\]

refers to the gross energy settlement quantity of resource \(j\) in reserve region \(a\) at dispatch interval \(i\) within settlement interval \(h\)

\[
\text{GA}_{p, r, a, i}
\]

refers to the generator allocation per common block \(p\) in reserve region \(a\) at dispatch interval \(i\) within settlement interval \(h\). It is the inverse of the number of generating units in a common block \(p\) as represented by the following formula:

\[
\text{GA}_{p, r, a, i} = \frac{1}{\sum_{j \in J} \text{RDS}_{j, r, a, i}}
\]

36 See Appendix C for explanatory example
Price Determination Methodology

ii. The reserve costs for lower contingency service shall be allocated among loads using gross energy settlement quantities, as determined under WESM Rules Clause 3.13.6, as provided in the following formula:

\[
CRCost_{b, r, a, h} = \sum_{i \in h} \left( RTA_{r,a,i} \times \frac{GESQ_{b, a, i}}{\sum_{b \in B} GESQ_{b, a, i}} \right)
\]

Where:

- \(CRCost_{b, r, a, h}\) refers to the reserve cost to be paid by load \(b\) in reserve region \(a\) for reserve category \(r\) at settlement interval \(h\).
- \(RTA_{r,a,i}\) refers to contingency reserve trading amount in reserve region \(a\) for reserve category \(r\) at dispatch interval \(i\) within settlement interval \(h\).
- \(GESQ_{b,a,i}\) refers to the gross energy settlement quantity of load \(b\) in reserve region \(a\) at dispatch interval \(i\).

8.2.4 Aggregate Trading Amount

a. The aggregate trading amount for a Trading Participant for a settlement interval is determined shall be determined as follows.\(^{37}\)

i. Energy trading amounts, which may be positive or negative for any Trading Participant; plus

ii. Reserve trading amounts for each reserve region, which shall always be positive for both Generation Companies and Customers; plus

iii. Upon approval of the trading of financial transmission rights, the transmission right trading amounts for each transmission right held by the WESM Participant; less

iv. The reserve cost recovery charges determined for that Trading Participant with respect to any reserve cost recovery zone, which will be positive for any Trading Participant.

b. This is provided in the following formula:

\[
TA_{p,h} = \sum_{j \in p} ETA_{j,h} + \sum_{j \in p} \sum_{r \in R_j} RTA_{j,r,a,h} + \sum_{t \in T_p} TRTA_{t,h} - \sum_{j \in p} RCRA_{j,h}
\]

\(^{37}\) WESM Rules Clause 3.13
Where:

\( TA_{p,h} \) refers to the aggregate trading amount of trading participant \( p \) for settlement interval \( h \)

\( ETA_{j,h} \) refers to the energy trading amount of resource \( j \) at settlement interval \( h \)

\( RTA_{j,r,a,h} \) refers to the reserve trading amount of resource \( j \) for reserve category \( r \) and reserve region \( a \) at settlement interval \( h \)

\( TRTA_{t,h} \) refers to the transmission rights trading amount of transmission right \( t \) at settlement interval \( h \)

\( RCRA_{j,h} \) refers to the reserve cost recovery amount of resource \( j \) for settlement interval \( h \) computed as the sum of resource \( RRCost_{j,REG,r,a,h} \), \( CRCost_{k,r,a,h} \), and \( CRCost_{b,r,a,h} \), as applicable

\( J_p \) refers to the set of all resources associated with trading participant \( p \)

\( R_j \) refers to the set of all reserve categories participated in by resource \( j \)

\( T_p \) refers to the set of all transmission rights associated with trading participant \( p \)

### 8.3 Additional Compensation

**8.3.1** A Trading Participant may be entitled to additional compensation when the costs incurred in complying with dispatch instructions are not sufficiently covered by the trading amounts related to settlement intervals with dispatch intervals under any of the following conditions:

a. Market suspension or market intervention; or

b. When the same Trading Participant was designated as must-run unit.

**8.3.2** A Trading Participant may also be entitled to additional compensation when the costs incurred in providing reserves based on capacity fees are not sufficiently covered by the trading amounts related to dispatch intervals under market suspension or market intervention.

**8.3.3** Trading Participants shall submit sufficient proof regarding the following costs incurred:

a. fuel costs; and

b. variable operating and maintenance costs, which may include start-up cost and shut-down costs.

**8.3.4** The additional compensation for dispatch intervals under market suspension or market intervention shall not be more than the difference of the total costs in Section 8.3.3 and the amount of the energy administered price or reserve administered price, as applicable, either paid or payable, subject to the determination and approval of the Market Operator.
8.3.5 Should a generating unit be designated as must-run unit, the Market Operator shall determine the must-run unit quantity/volume that shall be considered for additional compensation. This must-run unit volume is the total gross energy settlement quantity, as determined under WESM Rules Clause 3.13.6, of that generating unit minus the bilateral contract quantity declared for that unit, as provided in the following formula:

\[ \text{MRU Quantity}_{k,i} = \text{GESQ}_{k,i} - \text{BCQ}_{k,i} \]

Where:

- \( \text{GESQ}_{k,i} \) refers to the gross energy settlement quantity for generator resource \( k \) at dispatch interval \( i \)
- \( \text{BCQ}_{k,i} \) refers to the bilateral contract quantity declared for generator resource \( k \) at dispatch interval \( i \)

a. If a generating unit was scheduled beyond the minimum limit declared by the System Operator in the security limit, then the MRU Volume shall be zero (0).

b. In cases where the calculated MRU Volume is less than zero, then the MRU Volume shall be equal to zero.

c. The additional compensation shall be pro-rated among the customers in the same region based on gross energy settlement quantities.

8.4 Settlement Amounts

8.4.1 For each billing period, the Market Operator shall determine the settlement amount for each Trading Participant as follows:\(^{38}\)

a. The sum of the aggregate trading amounts for the settlement intervals in that billing period; plus

b. Any amount payable by the Market Operator to that Trading Participant in respect of that billing period and not accounted for in the aggregate trading amounts; less

c. The sum of any market fees which that Trading Participant is required to pay in respect of that billing period.

8.4.2 This is provided in the following formula:

\[ \text{SA}_{p,m} = \sum_{h \in H_m} (\text{TA}_{p,h} + \text{OTA}_{p,h}) - \text{MF}_{p,m} \]

Where:

\(^{38} \text{WESM Rules Clause 3.13} \)
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\[ \text{SA}_{p,m} \] refers to the settlement amount of trading participant \( p \) for billing period \( m \)

\[ \text{TA}_{p,h} \] refers to the aggregate trading amount of trading participant \( p \) for settlement interval \( h \)

\[ \text{OTA}_{p,h} \] refers to other trading amounts of trading participant \( p \) for settlement interval \( h \)

\[ \text{MF}_{p,m} \] refers to the market fee payments of trading participant \( p \) for billing period \( m \)

**SECTION 9  ALLOCATION OF NET SETTLEMENT SURPLUS**

9.1 Scope

9.1.1 This section provides the formula used to determine and allocate the net settlement surplus, which refers to the difference between the collections from and payments to Trading Participants.\(^{39}\)

9.1.2 This section shall only apply to energy transactions since the reserve market implements a cost recovery that does not result to any net settlement surplus.

9.2 Calculation of Net Settlement Surplus

9.2.1 The net settlement surplus amount shall be calculated per dispatch interval as follows:

\[ \text{NSS}_i = \text{Collectibles}_i - \text{Payables}_i \]

Where:

\[ \text{NSS}_i \] refers to the net settlement surplus at dispatch interval \( i \)

\[ \text{Collectibles}_i \] refers to the total amount to be collected by the Market Operator from the Trading Participants for energy transactions in the WESM at dispatch interval \( i \)

\[ \text{Payables}_i \] refers to the total amount to be paid by the Market Operator to the Trading Participants for energy transactions in the WESM at dispatch interval \( i \)

9.2.2 In case the collectibles are less than the payables resulting to a net settlement deficit, the deficit shall be recovered from the Trading Participants. In this case, the net settlement surplus referred to would be a negative amount and the rebate referred to shall also be a negative amount.

\(^{39}\) WESM Rules Clause 3.13
9.3 Recipient of Net Settlement Surplus

9.3.1 *WESM Trading Participants* that paid for the loss and congestion charge shall receive a share in the *net settlement surplus*.

9.3.2 The allocation mechanism shall only be up to the level of the registered *Trading Participants*.

9.4 Flow Back of Net Settlement Surplus

9.4.1 The *net settlement surplus* shall be allocated to each *WESM Participant* based on each recipient’s share in the total amount of loss and congestion charges.

9.4.2 The amount to be returned shall be equal to the ratio of the recipient’s loss and congestion charges to the total loss and congestion charges of all recipients multiplied by the total *net settlement surplus* amount, as represented by the following formula:

\[ R_{p,h} = \sum_{i \in h} \left( NSS_i \times \frac{LLCC_{p,i}}{\sum_{p \in P} LLCC_{p,i}} \right) \]

Where:

- \( R_{p,h} \) refers to the rebate amount or *net settlement surplus* allocation for *Trading Participant* \( p \) at settlement interval \( h \)
- \( NSS_i \) refers to the *net settlement surplus* at dispatch interval \( i \)
- \( LLCC_{p,i} \) refers to the line loss and congestion charges payments of *Trading Participant* \( p \) at dispatch interval \( i \)
- \( P \) refers to the set of all *Trading Participants*
- \( p \) refers to any *Trading Participant* paying line loss congestion charges to which a pro-rated amount of the *net settlement surplus* will be returned

a. The line loss and congestion charge payment shall be determined as follows:

\[ LLCC_{p,i} = \sum_{n \in N_p} \left( LLCP_{n,i} \times \sum_{j \in I_p} GESQ_{j,n,i} \right) - \sum_{c \in C_p} \left( LLCP_{p,c,i} \times BCQ_{p,c,i} \right) \]

Where:
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**LLCC\textsubscript{p,i}** refers to the line loss and congestion charges payments of Trading Participant \( p \) at dispatch interval \( i \)

**LLCP\textsubscript{n,i}** refers to the line loss and congestion price at market trading node \( n \) at dispatch interval \( i \)

**\( N_p \)** refers to the set of market trading nodes assigned to WESM Participant \( p \)

**\( J_{n,p} \)** refers to the set of resources of Trading Participant \( p \) at market trading node \( n \)

**GESQ\textsubscript{j,n,i}** refers to the gross energy settlement quantity of resource \( j \) in market trading node \( n \) at dispatch interval \( i \)

**LLCP\textsubscript{p,c,i}** refers to the line loss and congestion price at the reference bilateral nodal energy dispatch price between Trading Participant \( p \) and counterparty \( c \) at dispatch interval \( i \)

**BCQ\textsubscript{p,c,h}** refers to the declared bilateral contract quantity between WESM Participant \( p \) and counterparty \( c \) at dispatch interval \( i \)

**\( C_p \)** refers to the set of counterparties of Trading Participant \( p \)

b. In case the line loss and congestion charge payment for a dispatch interval of a trading participant is a positive value, the line loss and congestion charge payment for the Trading participant for that dispatch interval shall be set to zero (0). Consequently, that resource shall have zero (0) net settlement surplus allocation for that dispatch interval.

c. The line loss and congestion price for a dispatch interval for each resource shall be calculated as follows:

\[
\text{LLCP}_{n,i} = (\text{MLC}_{n,i} + \text{MCC}_{n,i}) - (\text{MLC} + \text{MCC})_{\text{lowest}}
\]

Where:

- **\( \text{LLCP}_{n,i} \)** refers to the line loss and congestion price at market trading node \( n \) at dispatch interval \( i \)
- **\( \text{MLC}_{n,i} \)** refers to the marginal loss cost at market trading node \( n \) at dispatch interval \( i \)
- **\( \text{MCC}_{n,i} \)** refers to the marginal congestion cost at market trading node \( n \) at dispatch interval \( i \)
- **\( (\text{MCC} + \text{MLC})_{\text{lowest}} \)** refers to the lowest aggregated marginal loss cost and marginal congestion cost for dispatch interval \( i \)

d. In case the nodal energy dispatch price of a resource was not determined using the market dispatch optimization model in accordance with WESM Rules Clause 3.6, the line loss and congestion cost price of that resource shall be set to zero (0). Consequently, that resource shall have zero (0) net settlement surplus allocation for that dispatch interval.

9.4.3 In case the nodal energy dispatch prices of all resources in a dispatch interval were not determined using the market dispatch optimization model in accordance with
WESM Rules Clause 3.6, the net settlement surplus for that dispatch interval shall be allocated to customer resources on a pro-rata basis depending on each customer resource’s share in the total gross energy settlement quantity, as determined under WESM Rules Clause 3.13.6, of all customer resources. The allocation shall be performed on a per customer resource basis associated to the WESM Participants. Generator resources shall not have an allocation of the net settlement surplus during this case.

The amount to be returned shall be equal to the ratio of the customer resource’s gross energy settlement quantity to the total gross energy settlement quantity of all customer resources multiplied by the total net settlement surplus amount, as represented by the following formula:

\[ R_{b,i} = \frac{NSS_i \times \sum_{b \in B} GESQ_{b,i}}{GESQ_{b,i}} \]

Where:
- \( R_{b,i} \) refers to the rebate amount or net settlement surplus allocation for customer resource \( b \) at dispatch interval \( i \)
- \( NSS_i \) refers to the net settlement surplus at dispatch interval \( i \)
- \( GESQ_{b,i} \) refers to the gross energy settlement quantity of customer resource \( b \) at dispatch interval \( i \)
- \( B \) refers to the set of all customer resources

9.5 Submission of Report to the ERC

The Market Operator shall submit an annual report on monthly levels of net settlement surplus and review of underlying factors giving rise to net settlement surplus every June 25 of the following year.
The publication and effectivity of this *Market Manual* shall be in accordance with the resolution of the *ERC*.
Appendix A – Detailed Formulation
Appendix B – Tie Breaking (Illustrative Example)

Generator A and B have a maximum capacity of 70 MW and 90 MW, respectively, and both are located at the same location with the same offer price.

The price curve of Gen A is shown below.

![Figure 1. Generator A Price Curve](image)

The price curve of Gen B is shown below.

![Figure 2. Generator B Price Curve](image)

If the total load is 140 MW, both the first blocks of the price curves of generators A and B shall be scheduled at 50 MW each, hence, fulfilling 100 MW of the 140 MW load requirement.
The remaining 40 MW load requirement shall then be pro-rated as follows.

- Next block in price curve of Gen A is 20 MW at P2,000/MWh
- Next block in price curve of Gen B is 40 MW at P2,000/MWh also

Additional Schedule for Gen A = \( 40 \times \left[ \frac{20}{40+20} \right] \) = 13.33 MW

Additional Schedule for Gen B = \( 40 \times \left[ \frac{40}{40+20} \right] \) = 26.67 MW

Provided as such, Generator A shall have a total schedule of 63.33 MW (50+13.33), while Generator B shall have a total schedule of 76.67 MW (50 + 26.67).
Appendix C – Cost Recovery for Raise Contingency Reserves

As provided in Section 8.2.3, the reserve costs for contingency service shall be allocated among generators based on energy scheduled, representing the amount contributed to the reserve requirement. Generators are held responsible for the incremental contribution to the reserve requirement by sharing the costs for the incremental increase with the larger units, and the underlying reserve requirements with the smaller units.

This is illustrated in the following figure:

<table>
<thead>
<tr>
<th>COMMON BLOCK 1 = 90 MW</th>
<th>COUNT OF GENERATORS SHARING IN A BLOCK</th>
<th>GENERATOR ALLOCATION PER BLOCK</th>
</tr>
</thead>
<tbody>
<tr>
<td>GEN A - GEN C</td>
<td>1</td>
<td>1</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>COMMON BLOCK 2 = 90 MW</th>
<th>COUNT OF GENERATORS SHARING IN A BLOCK</th>
<th>GENERATOR ALLOCATION PER BLOCK</th>
</tr>
</thead>
<tbody>
<tr>
<td>GEN C - GEN B</td>
<td>2</td>
<td>0.5</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>COMMON BLOCK 3 = 30 MW</th>
<th>COUNT OF GENERATORS SHARING IN A BLOCK</th>
<th>GENERATOR ALLOCATION PER BLOCK</th>
</tr>
</thead>
<tbody>
<tr>
<td>GEN C - GEN D</td>
<td>3</td>
<td>0.33</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>COMMON BLOCK 4 = 40 MW</th>
<th>COUNT OF GENERATORS SHARING IN A BLOCK</th>
<th>GENERATOR ALLOCATION PER BLOCK</th>
</tr>
</thead>
<tbody>
<tr>
<td>GEN D</td>
<td>4</td>
<td>0.25</td>
</tr>
</tbody>
</table>

Figure 3. Sample Representation for Cost Recovery for Raise Contingency Reserves

In the above figure, the generators are ordered by manner of decreasing energy schedule. Doing so will show the “common blocks”, which are capacities common to generators that necessitate a certain amount of reserve requirement and whose cost will be shared equally among them.

For instance, Common Block 4 (40 MW) is shared by Gen A, B, C and D, and hence, its cost will be split equally among them. In the same manner, Common Block 3 (30 MW) is shared only by Generators A, B and C, in which Gen D has no amount due, as its worst possible outage that would utilize reserve is limited to 40 MW only.

As previously stated, the following formula represents the attributable reserve cost to a certain generator k.

\[
CRCost_{k, r, a, h} = \sum_{i \in h} \left(\sum_{p \in P} \frac{GA_{p, r, a, i} \cdot SQTY_{k, p, r, a, i}}{\sum_{j \in J} RDS_{j, r, a, i}} \right)
\]

Whereas \(GA_{p, r, a, i}\) is calculated as follows.

\[
GA_{p, r, a, i} = \frac{1}{\text{No. of Generators sharing in block } p \text{ in reserve area } a \text{ for reserve category } r \text{ at dispatch interval } i}
\]

Based on Figure 3, the generator allocation for Common Block 4 is:
Suppose that the total reserve amount to be paid for certain dispatch interval “i” is P30,000, then the reserve cost attributable to GEN D is:

\[ \text{CRCost}_{D,r,a,i} = 30,000 \times \left( \frac{0.25 \times 40}{250} \right) = \text{P1,200} \]

As for GEN C, it shares in common block 3 and 4. With \( \text{GA}_3 \) being computed as 0.33 and \( \text{GA}_4 \) being 0.25 (as shown in Figure 3), then the reserve cost attributable to GEN C is:

\[ \text{CRCost}_{C,r,a,i} = 30,000 \times \left( \frac{0.25 \times 40}{250} \right) + \left( \frac{0.33 \times 30}{250} \right) = \text{P2,400} \]

In the same manner, GEN B will pay P7,800 while GEN A will pay P18,600.