PUBLIC

WESM Manual

Price Determination Methodology

Issue 4.0 | WESM-PDM

This Market Manual sets out the mechanism for determining the prices and settlements in the Philippine Wholesale Electricity Spot Market.

Approval Date: 12-Jan-2024 | Publication Date: 29-Jan-2024

PEMC Website Posting Date: 05-Mar-2024 | Effective Date: 13-Feb-2024

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
	PEMC	26 June 2006	Original document, as approved by the ERC on 20 June 2006 under ERC Decision on Case No. 2006-007 RC
1.0	PEMC	26 June 2021	Implementation of enhancements to WESM design and operations and consolidation of 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 6. Management of Must-run and Must-stop Units (MRU Manual), Issue 6
2.0	PEMC		Amendments to the PDM promulgated in Department of Energy (DOE) in its Department Circular No. DC2018-04-0012 (dated 28 March 2018) entitled *"Adopting Further Amendments to the Wholesale Electricity Spot Market (WESM) Manuals on Price Determination Methodology and Constraint Violation Coefficients and Pricing Re-Run for the Implementation of the Enhancements to the WESM Design and Operations"*
3.0	PEMC/ IEMOP		Revised to reflect the approved changes to the Price Determination Methodology and to harmonize with subsequent issuances, as follows: 1. Amendments to the PDM promulgated by the DOE in Department Circular No. DC2018-06-0017 (dated 28 June 2018) entitled "*Adopting Further Amendments to the Wholesale Electricity Spot Market Rules and Market Manuals (Transitory Provisions for the Implementation of WESM in Mindanao)*";* 2. Amendments to the rules on allocation of the net settlement surplus/deficit set out in ERC Resolution No. 07, Series of 2019 entitled *"A Resolution Adopting Amendments to the Rules for the Distribution of Net Settlement Surplus (NSS)"*; and 3. Decision dated 20 August 2020 (promulgated on 29 December 2020) and other Orders of the Energy Regulatory Commission (ERC) on ERC Case No. 2017-042 RC.
	PEMC		Revised formatting for the commencement of the enhanced WESM design and operations per DOE Department Circular No. DC2021-06-0015.
4.0	MSC and CC	13 Feb 2024	Reflect amendments requiring Trading Participants to accurately reflect the available capacity of their generating units in their market offers.

**Previously tagged as Issue 2.0 by PEMC. Per DOE, this version is Issue 3.0.*

Document Approval

<table>
<tr><th>Issue No.</th><th>RCC Approval</th><th>RCC Resolution No.</th><th>PEM Board Approval</th><th>PEM Board Resolution No.</th><th>DOE Approval</th><th>DOE Department Circular No.</th><th>ERC Approval</th></tr>
<tr><td>1.0</td><td>09 November 2016</td><td>2016-13</td><td>29 November 2016</td><td>2016-41</td><td>20 March 2017</td><td>DC2017-03-0001</td><td rowspan="3">Decision promulgated on 29 December 2020 on ERC Case No. 2017-042 RC</td></tr>
<tr><td>2.0</td><td>09 June 2017</td><td>2017-07</td><td>18 September 2017</td><td>2017-17</td><td>28 March 2018</td><td>DC2018-04-0012</td></tr>
<tr><td>3.0</td><td>25 April 2018</td><td>2018-01</td><td>03 May 2018</td><td>2018-19</td><td>26 June 2018</td><td>2018-06-0017</td></tr>
<tr><td>4.0</td><td>12 May 2023</td><td>2023-04</td><td>27 Jun 2023</td><td>2023-61-01</td><td>12 Jan 2024</td><td>2024-01-0003</td><td>N/A</td></tr>
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Reference Documents

Document ID	Document Title
	Electric Power Industry Reform Act (EPIRA)
	WESM Rules
	Market Manuals

Contents

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 *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 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

[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
[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

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* shall be priced and settled in accordance with the market design principles as issued by the *DOE;*[10]
b. Methodology by which *energy* 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* shall be settled in the *WESM*, 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 –

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.*

[10] *DOE* Circular 2015-10-0015, "Providing Policies for further Enhancement of the *Wholesale Electricity Spot Market (WESM)* Design and Operations", dated 23 October 2015
[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

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

k. **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.

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

m. **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*.

n. **Snapshot Quantity.** The actual instantaneous injection, withdrawal, or line flow of power, in MW, at the end of a *dispatch interval.*

o. **System marginal price**. The shadow price for which *energy* is priced.

p. **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.

q. **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.

SECTION 3 RESPONSIBILITIES

3.1 PEMC

As the governance arm of *WESM,* the *Philippine Electricity Market Corporation (PEMC)* shall be responsible for the development, validation, maintenance, publication, and revision of this *Market Manual* in coordination with the *Market Operator* and *WESM Members.*

3.2 Market Operator

The *Market Operator* shall be responsible for the implementation of this *Market Manual* and the provision of necessary information and references to *PEMC* for the subsequent revisions and validation of this *Market Manual.*

3.3 System Operator

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

3.4 Trading Participants

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

3.5 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 Rules*[15].

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
    - *Must-run generation*
  - Non-security limits
    - Testing and commissioning

f. Reserve requirements.

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. Nodal *load forecast;* and
c. *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]

[15] *WESM Rules* Clause 3.5
[16] *WESM Rules* Clause 3.6.1.3

It is represented by the following formulation:

Maximize the *economic gain* from trade, where:

$$\text{Economic Gain} = \sum_{i}^{n}\left\{\sum_{b}^{E_D}\left[(DB_{b,i})(PDB_{b,i})\right] - \sum_{k}^{E_G}\left[(G_{k,i})(PG_{k,i})\right] - \sum_{r}^{N_R}\sum_{j}^{E_R}\left[(R_{j,r,i})(PR_{j,r,i})\right] - \sum_{c}^{E_C}\left[(CQ_{c,i})(CP_{c,i})\right] - \sum CVP\right\}$$

Where:

i	refers to a specific *dispatch interval*
n	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*
E_C	refers to the number of curtailed loads in a dispatch interval i
$CQ_{c,i}$	refers to the nodal load curtailment quantity *c* at *dispatch interval i*
$CP_{c,i}$	refers to the nodal load 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*:

[17] *WESM Rules* Clause 3.4.1.2

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*

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**[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:[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, namely:*
    - *Non-scheduled* generation *constraint;*
    - *Priority dispatch* generation *constraint; and*
    - *Must dispatch* 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;
c. Losses by each equipment and in aggregate;
d. *Dispatch schedules*
    i. *Energy;* and

[20] *WESM Rules* Clauses 3.6.1.3 and 3.6.2

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:

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

Where:

LMP_j	refers to the locational marginal price at location *j*
λ	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:

$$TLF_j = \frac{1}{1 - \frac{\partial P_{Loss}}{\partial P_j}}$$

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:

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

Where:

μ_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*

It is noted that the *market dispatch optimization model's* (MDOM) power flow solution includes an output for the sensitivity factor, which reflects the MW impact (or contribution) of a generator or load on a transmission equipment.[21]

4.11 Reserves

Reserve and *energy dispatch schedules* shall be determined in a co-optimized manner in the *market dispatch optimization model*.[22]

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* 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.

[21] For example, if a generator reflects a sensitivity factor is 0.4 towards a constrained equipment, it means that for every 1 MW of generation injected by the generator, 0.4 MW is transmitted to the constrained equipment.
[22] *WESM Rules* Clause 3.6

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*[23].

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

4.12.5 If a dispatch interval is subject to both the prices determined in accordance with Sections 4.12.3 and 4.12.4, the lower of the two prices shall apply in the settlement of transactions for that interval.

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:

$$\text{FEDP}_{z,b,i} = \frac{\sum_{b \in B_z} \left(\text{FEDP}_{b,i} * \text{EDS}_{b,i}\right)}{\sum_{b \in B_z} \text{EDS}_{b,i}}$$

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:

$FEDP_{z,b,i}$	refers to the zonal *final nodal energy price* of *customer* resource *b* at *dispatch interval i* within *customer pricing zone z*
$FEDP_{b,i}$	refers to the *final nodal energy dispatch price* as determined under Section 4.12 for *customer* resource *b* at *dispatch interval i*
$EDS_{b,i}$	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*

[23] 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.

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.[24]

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*.[25]

5.2 **Automatic Pricing Re-Run**

5.2.1 *Automatic pricing reruns* for *market projections* and *real-time dispatch* shall ensure that the *energy prices* reflect the marginal costs of supplying *energy* at each *node,* regional, or island level.

5.2.2 The *automatic pricing re-run* of the *market dispatch optimization model* shall determine the prices for *energy* 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 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*.

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

Soft Constraint	Violation	Constraint Relaxation during Pricing Re-Run	Re-run Price[26]
Thermal Base Case	X	x + delta	EDP
Transmission Group	X	x + delta	EDP
Self-Scheduled Generation *Constraint*	X	x + delta	EDP
System Energy Balance (Over-generation and under-generation)	X	x + delta	EDP

[24] *WESM Rules* Clause 3.6.7
[25] *WESM Rules* Clause 3.10.5
[26] EDP refers to *nodal energy dispatch price*

Soft Constraint	Violation	Constraint Relaxation during Pricing Re-Run	Re-run Price[26]
Nodal Value of Lost Load or Nodal Energy Balance	X	x + delta	EDP
Thermal Contingency	X	x + delta	EDP
Reserve Requirement	X	x + delta	EDP

5.2.6 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.[27]

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.

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[28].

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.

[27] *WESM Rules* Clause 3.10.5
[28] *WESM Rules* Clause 3.12.7

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:

$$\text{Price Trigger Factor}_i = \textbf{ABS}\left(\frac{\sqrt{\frac{\sum_{j\in J}\left[EDS_{j,i} * \left(EDP_{j,i} - NWAP_i\right)^2\right]}{\sum_{j\in J}\left(EDS_{j,i}\right)}}}{NWAP_i} \right)$$

Where:

J	refers to the set of all resources
$EDS_{j,i}$	refers to the *energy dispatch schedule* of resource *j* at *dispatch interval i*
$EDP_{j,i}$	refers to the *nodal energy dispatch price* of resource *j* at *dispatch interval i*
$NWAP_i$	refers to the weighted average price of all resources and computed as:

$$NWAP_i = \frac{\sum_{j\in J}\left(EDP_{j,i} * EDS_{j,i}\right)}{\sum_{j\in J}\left(EDS_{j,i}\right)}$$

6.2.4 The price substitution methodology set forth in this section shall apply to a *dispatch interval* when the trigger factor **exceeds** 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. The result of the review shall be submitted to the *ERC* for information and approval.

6.2.5 The price substitution methodology shall be implemented in all the *regions* where the *WESM* is in operation. In cases where a *region/s* has no interconnection with other *regions*, or has no exchange of power with other *regions*, this *region*/s shall be separately assessed for the application of the price substitution methodology.

6.2.6 The *dispatch schedules* arrived at in the original (constrained) market solution for the relevant *dispatch interval* will stand and will be the basis for *dispatch* by the *System Operator* irrespective of the results of the unconstrained solution. Re-dispatch of generation units will be implemented by the *System Operator* in accordance with relevant provisions of the *WESM Rules* and *Market Manuals*, the *Philippine Grid Code* and other relevant rules, regulations, issuances, guidelines and procedures.

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 All generators shall be paid at the *unconstrained solution's* marginal price. To enable *constrained-on generators* to recover its operating costs, they shall be eligible to claim for additional compensation under Section 8.3, subject to other rules and guidelines thereof as issued by the ERC.

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:

$$SEDP_{b,\ i} = \frac{\sum_{k \in K}\left(SEDP_{k,\ i} * EDS_{k,\ i}\right)}{\sum_{b \in B}\left(EDS_{b,\ i}\right)}$$

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 a *region/s* with congestion has no interconnection with other *regions*, or has no exchange of power with other *regions*, the provisions of Section 6.4.1 shall apply only to the region/s with congestion.

SECTION 7 ADMINISTERED PRICES

7.1 **Scope**

7.1.1 This section provides for 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.*[29]

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*.
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. The *administered price* will apply only to transactions above the declared *bilateral contract* quantities.
g. The *administered price* will be used for settlement of transactions in dispatch intervals during market intervention and suspension where the Market Operator is unable to generate a market schedule.

[29] *WESM Rules* Clause 6.2.3

h. 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.

7.2 **Generator Energy Administered Price**

7.2.1 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. The methodology set out in this Section shall not apply in cases where the *market suspension* or *market intervention* is classified as prolonged. In such cases, the applicable methodology approved by the ERC shall apply.[30] For the initial period[31] of the implementation of this methodology, an Interim Generator Energy Administered Price calculated in accordance with Appendix E shall be applied.

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 two (2) 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:

$$EAP_{k,D,i} = \frac{\sum_{d=D-1}^{D-n}\left(FEDP_{k,d,i} * SQ_{k,d,i}\right)}{\sum_{d=D-1}^{D-n} SQ_{k,d,i}}$$

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*

[30] Section 3.2.2 of the Dispositive portion of ERC Decision on ERC Case 2017-042RC dated 20 August 2020 and promulgated on 29 December 2020

[31] The initial period shall refer to the first four (4) weeks from the effective date of implementation of the methodology when there are valid prices.

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:

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

Where:

$EAP_{k,\,D,\,i}$	refers to the *energy administered price* for *generator* resource *k* for *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*
D	refers to the *trading day* with *dispatch interval* under *market intervention* or *market suspension*
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*

7.2.5 In case three (3) or 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:

$$EAP_{k,D,i} = \frac{\sum_{d=D-1}^{D-n}\left(EAP_{k,d,i} * SQ_{k,d,i}\right)}{\sum_{d=D-1}^{D-n} SQ_{k,d,i}}$$

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*
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 *energy administered prices* of the preceding similar *trading days* and similar *dispatch intervals* as set out in the following formula:

$$\mathrm{EAP}_{\mathrm{k,\,D,\,i}} = \frac{\sum_{\mathrm{d=D\text{-}1}}^{\mathrm{D\text{-}n}} \mathrm{EAP}_{\mathrm{k,\,d,\,i}}}{n}$$

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*
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 similar *trading day* and similar *dispatch interval*
n	refers to the number of similar *trading days* and *dispatch intervals*

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:

$$\mathrm{EAP}_{\mathrm{k,\,D,\,i}} = \frac{\sum_{\mathrm{k'\in K_i,k'\neq k}}\left(\mathrm{EAP}_{\mathrm{k',D,i}} \ * \ \mathrm{SQ}_{\mathrm{k',D,i}}\right)}{\sum_{\mathrm{k'\in K_i,k'\neq k}} \mathrm{SQ}_{\mathrm{k',D,i}}}$$

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 using snapshot quantities as follows:

$$\mathrm{EAP}_{\mathrm{b,i,D}} = \frac{\sum_{\mathrm{k\in K_{i,D}}}\left(\mathrm{EAP}_{\mathrm{k,i,D}} \ {}^{*}\mathrm{SQ}_{\mathrm{k,i,D}}\right)}{\sum_{\mathrm{b\in B}_{i,D}} \mathrm{SQ}_{\mathrm{b,i,D}}}$$

Where:

$EAP_{b,i,D}$	refers to the *energy administered price* for customer resource *b* for *dispatch interval i* of *trading day D*.
$EAP_{k,i,D}$	refers to the *energy administered price* for *generator* resource *k* at *dispatch interval i* of *trading day D*.
$SQ_{k,i,D}$	refers to the *snapshot quantity* for *generator* resource *k* at *dispatch interval i* of *trading day D*.
$SQ_{b,i,D}$	refers to the *snapshot quantity* for *customer* resource *b* at *dispatch interval i* of *trading day D*.
$K_{i,D}$	refers to the set of *generator* resources with positive *snapshot quantities* at *dispatch interval i* of *trading day D*.
$B_{i,D}$	refers to the set of all *customer* resources at *dispatch interval i* of *trading day D.*

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:

$$EAP_{b,i,D} = \frac{\sum_{k \in K_{i,D}} \left(EAP_{k,i,D} \ * \ SQ_{k,i,D}\right) + \left(SQ_{ITC,i,D} \ * \ GWAP_{NAR,i,D}\right)}{\sum_{b \in B_{i,D}} SQ_{b,i,D}}$$

Where:

$EAP_{b,i,D}$	refers to the *energy administered price* for customer resource *b* for *dispatch interval i* of *trading day D.*
$EAP_{k,i,D}$	refers to the *energy administered price* for *generator* resource *k* for *dispatch interval i* of *trading day D*.
$SQ_{k,i,D}$	refers to the *snapshot quantity* for *generator* resource *k* for *dispatch interval i* of *trading day D*.
$SQ_{ITC,i,D}$	refers to the *snapshot quantity* of the interconnection for *dispatch interval i* of *trading day D*.
$GWAP_{NAR,i,D}$	refers to the generator weighted average price in the non-administered region using *energy dispatch schedule and final energy dispatch price* for *dispatch interval i* of *trading day D*.
$SQ_{b,i,D}$	refers to the *snapshot quantity* for *customer* resource *b* at *dispatch interval i* of *trading day D*.
$K_{i,D}$	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* of *trading day D.*
$B_{i,D}$	refers to the set of all *customer* resources in the region under *market suspension* or *market intervention* at *dispatch interval i* of *trading day D*.

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:

$$EAP_{b,i,D} = \frac{\sum_{k \in K_{i,D}} (EAP_{k,i,D} \ * \ SQ_{k,i,D}) - (SQ_{ITC,i,D} \ * \ GWAEAP_{i,D})}{\sum_{b \in B_{i,D}} SQ_{b,i,D}}$$

Where:

$EAP_{b,i,D}$	refers to the *energy administered price* for *customer* resource *b* for *dispatch interval i* of *trading day D*.
$EAP_{k,i,D}$	refers to the *energy administered price* for *generator* resource *k* for *dispatch interval i* of *trading day D*.
$SQ_{k,i,D}$	refers to the *snapshot quantity* for *generator* resource *k* at *dispatch interval i* of *trading day D*.
$SQ_{ITC,i,D}$	refers to the *snapshot quantity* of the interconnection at *dispatch interval i* of *trading day D*.
$GWAEAP_i$	refers to the generator weighted average *energy administered price* using *snapshot quantity* for *dispatch interval i* of *trading day D*.
$SQ_{b,i,D}$	refers to the *snapshot quantity* (in MW) for *customer* resource *b* for *dispatch interval i* of *trading day D*.
$K_{i,D}$	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* of *trading day D*.
$B_{i,D}$	refers to the set of all *customer* resources in the region under *market suspension* or *market intervention* for *dispatch interval i* of *trading day D*.

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:

$$NARAPA_{b-NAR,i} = \frac{SQ_{ITC,i} * (GWAEAP_i - \ GWAP_{NAR,i})}{\sum_{b \in B-NAR_i} EDS_{b-NAR,i}}$$

Where:

$NARAPA_{b\text{-}NAR,i}$	refers to the non-administered region administered price adjustment for a *customer* resource within the non-administered region 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 at the non-administered region using the *final energy dispatch price* and the *energy dispatch schedule* for *dispatch interval i*
$GWAEAP_i$	refers to the generator weighted average *energy administered price* using *snapshot quantity* for *dispatch interval i*
$EDS_{b\text{-}NAR,i}$	refers to the *energy dispatch schedule* of *customer* resource *b* within the non-administered region for *dispatch interval i*
$B\text{-}NAR_i$	refers to the set of all *customer* resources within the non-administered region for *dispatch interval i*
b-NAR	refers to a *customer* resource within the non-administered region

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* for each *Trading Participant*;[32] and
b. Provision of additional compensation for *Trading Participants* affected by *market suspension or market intervention,* or whose facilities are designated as *must-run units,* or *constrain-on generating units,* or are *constrained-on generators,* and for facilities dispatched during *dispatch intervals* where price mitigation measures were applied.

8.2 Trading Amounts

8.2.1 Energy Trading Amount[33]

The *energy trading amount* for a *trading participant* 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:

$$\mathrm{ETA_{p,h}} = \sum_{\mathrm{i \in h}} \left[\sum\nolimits_{\mathrm{n \in N_p}} \left(\mathrm{FEDP_{n,i}} * \mathrm{GESQ_{n,i}} \right) - \sum_{\mathrm{b \in B_i}} \left(\mathrm{FEDP_{p,b,i}} * \mathrm{BCQ_{p,b,i}} \right) \right]$$

Where:

$ETA_{p,h}$	refers to the *energy trading amount* of *trading participant p* at *settlement interval h*
$FEDP_{n,i}$	refers to the *final energy dispatch price* of *market trading node n* at *dispatch interval i* in *settlement interval h*
$GESQ_{n,i}$	refers to the *gross energy settlement quantity* for *market trading node n* at *dispatch interval i* in *settlement interval h*
N_p	refers to the set of *market trading nodes* assigned to *trading participant p*
$FEDP_{p,b,i}$	refers to the reference *final nodal energy dispatch price* for the *bilateral contract quantity* between *trading participant p* and counterparty *b* at *dispatch interval i* in *settlement interval h* (default is *generator* FEDP)
$BCQ_{p,b,i}$	refers to the *bilateral contract quantity* between *trading participant p* and counterparty *b* at *dispatch interval i* in *settlement interval h*
B_i	refers to the set of counterparties that *trading participant p* has a contract with at *dispatch interval i*

[32] *WESM Rules* Clause 3.13
[33] *WESM Rules* Clause 3.13

8.2.2 Aggregate Trading Amount

a. The aggregate *trading amount* for a *Trading Participant* for a *settlement interval* is determined shall be determined as follows:[34]

Energy trading amounts, which may be positive or negative for any *Trading Participant.*

b. This is provided in the following formula:

$$\mathrm{TA_{p,h}} = \mathrm{ETA_{p,h}}$$

Where:

$TA_{p,h}$	refers to the aggregate *trading amount* of *trading participant p* for *settlement interval h*
$ETA_{p,h}$	refers to the energy *trading amount* of *trading participant p* at *settlement interval h*

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* in accordance with Section 7*;*
b. When a *Trading Participant* has a generating unit that was designated as *must-run unit* or *constrain-on generating unit* and was paid at the *WESM* price in accordance with Section 4.12;
c. When a *Trading Participant* was scheduled as a *constrained-on generator* and was paid at the price in accordance with Section 6; or
d. When a *Trading Participant* was scheduled and dispatched in dispatch intervals when price mitigation measure imposed by the ERC was applied as referred to in Section 4.12.3. It is provided, however, that the entitlement to additional compensation shall be in accordance with the criteria, requirements and procedures set out in the relevant issuance declaring the application of the price mitigation measure.

8.3.2 *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.

The documents and other data that will constitute sufficient proof, as well as the procedures for submission of claims for additional compensation shall be as provided for in the WESM Billing and Settlement Manual and other relevant Market Manual approved for use in the WESM.

8.3.3 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 8.3.2 and

[34] *WESM Rules* Clause 3.13

the amount of the *energy administered price, as applicable,* either paid or payable, subject to the determination and approval of the *Market Operator*.

8.3.4 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. The *Market Operator* shall refer to the report of the *System Operator* on the *generating units* that were designated as *must-run unit.* The report of the System Operator shall be prepared, validated, and published in accordance with the provisions of the WESM Rules and the WESM Dispatch Protocol on reporting of must-run unit designation. 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 and corresponding incidental energy generated by that same unit in compliance with a *dispatch instruction* to provide *ancillary services* by the *System Operator*, as provided in the following formula:

$$\text{MRU Quantity}_{k,\,i} = \text{GESQ}_{k,i} - \text{BCQ}_{k,i} - \text{Incidental Energy}_{k,i}$$

Where:

$GESQ_{k,\,i}$	refers to the *gross energy settlement quantity* for *generator* resource *k* at *dispatch interval i*
$BCQ_{k,\,i}$	refers to the *bilateral contract quantity* declared for *generator* resource *k* at *dispatch interval i*
Incidental $\text{Energy}_{k,I}$	if applicable, refers to the incidental energy produced by *generator* resource *k* at *dispatch interval i* as a result of providing ancillary services

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: [35]

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:

[35] *WESM Rules* Clause 3.13

$$SA_{p,m} = \sum_{h \in H_m} (TA_{p,h} + OTA_{p,h}) - MF_{p,m}$$

Where:

$SA_{p,m}$	refers to the *settlement amount* of *trading participant p* for *billing period m*
$TA_{p,h}$	refers to the aggregate *trading amount* of *trading participant p* for *settlement interval h*
$OTA_{p,h}$	refers to other *trading amounts* of *trading participant p* for *settlement interval h*
$MF_{p,m}$	refers to the *market fee* payments of *trading participant p* for *billing period m*

SECTION 9 ALLOCATION OF NET SETTLEMENT SURPLUS AND NET SETTLEMENT DEFICIT

9.1 Scope

9.1.1 This section provides the formula used to determine and allocate the *net settlement surplus* or *net settlement deficit,* which refers to the difference between the collections from and payments to *Trading Participants.*[36]

9.1.2 This section shall only apply to *energy* transactions.

9.2 Calculation of Net Settlement Surplus

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

$$NSS_{Total,i} \text{ or } NSD_{Total,i} = ETA_{Collectibles,i} - ETA_{Payables,i}$$

Where:

$NSS_{Total,i}$	refers to the total *net settlement surplus* at *dispatch interval i*
$NSD_{Total,i}$	refers to the total *net settlement deficit* at *dispatch interval i*
$ETA_{Collectibles,i}$	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*
$ETA_{Payables,i}$	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 The total *net settlement surplus* or *net settlement deficit* shall be disaggregated according to those resulting from loss *trading amounts* and from congestion *trading amounts*.

a. The total energy trading amount per dispatch interval can be disaggregated as follows:

[36] *WESM Rules* Clause 3.13

$$
\begin{aligned}
\mathrm{ETA}_{\mathrm{Collectibles,i}} \text{ or } \mathrm{ETA}_{\mathrm{Payables,i}} \\
&= \sum_{\mathrm{cp} \in \mathrm{CP}} \mathrm{ETA}_{\mathrm{Energy,p,i}} + \sum_{\mathrm{cp} \in \mathrm{CP}} \mathrm{ETA}_{\mathrm{Loss,p,i}} \\
&+ \sum_{\mathrm{cp} \in \mathrm{CP}} \mathrm{ETA}_{\mathrm{Congestion,p,i}}
\end{aligned}
$$

Where:

$ETA_{Collectibles,i}$	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*
$ETA_{Payables,i}$	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*
$ETA_{Energy,p,i}$	refers to energy component of the amount to be collected or paid by the *Market Operator* from or to *Trading Participant p* for *energy* transactions in the *WESM* at *dispatch interval i*
$ETA_{Loss,p,i}$	refers to loss component of the amount to be collected or paid by the *Market Operator* from or to *Trading Participant p* for *energy* transactions in the *WESM* at *dispatch interval i*
cp	refers to a Trading Participant with a collectible amount
CP	refers to the set of all Trading Participants with collectible amounts
pp	refers to a Trading Participant with a payable amount
PP	refers to the set of all Trading Participants with payable amounts

b. The NSS or NSD due to losses shall be calculated as follows:

$$
\begin{aligned}
\mathrm{NSS}_{\mathrm{Loss,i}} \text{ or } \mathrm{NSD}_{\mathrm{Loss,i}} \\
&= \sum_{\mathrm{cj} \in \mathrm{CJ}} (\mathrm{ETA}_{\mathrm{Energy,cj,i}} + \mathrm{ETA}_{\mathrm{Loss,cj,i}}) \\
&- \sum_{\mathrm{pj} \in \mathrm{PJ}} (\mathrm{ETA}_{\mathrm{Energy,pj,i}} + \mathrm{ETA}_{\mathrm{Loss,pj,i}})
\end{aligned}
$$

Where:

$NSS_{Loss,i}$	refers to the *net settlement surplus* due to losses at *dispatch interval i*
$NSD_{Loss,i}$	refers to the *net settlement deficit* due to losses at *dispatch interval i*
$ETA_{Energy,cj,i}$	refers to energy component of the amount to be collected by the *Market Operator* from resource *cj* for *energy* transactions in the *WESM* at *dispatch interval i*
$ETA_{Loss,cj,i}$	refers to loss component of the amount to be collected by the *Market Operator* from resource *cj* for *energy* transactions in the *WESM* at *dispatch interval i*
$ETA_{Energy,pj,i}$	refers to the energy component of the amount to be paid by the *Market Operator* to resource *pj* for *energy* transactions in the *WESM* at *dispatch interval i*

$ETA_{Loss,pj,i}$	refers to the loss component of the amount to be paid by the *Market Operator* to resource *pj* for *energy* transactions in the *WESM* at *dispatch interval i*
cj	refers to a resource with a collectible amount
CJ	refers to the set of all resource with collectible amounts
pj	refers to a resource with a payable amount
PJ	refers to the set of all resources with payable amounts

c. The NSS or NSD due to congestion shall be calculated as follows:

$$NSS_{Congestion,i} \text{ or } NSD_{Congestion,i} = \sum_{cj \in CJ} ETA_{Congestion,cj,i} - \sum_{pj \in PJ} ETA_{Congestion,pj,i}$$

Where:

$NSS_{Congestion,i}$	refers to the *net settlement surplus* due to congestion at *dispatch interval i*
$NSD_{Congestion,i}$	refers to the *net settlement deficit* due to congestion at *dispatch interval i*
$ETA_{Congestion,cj,i}$	refers to congestion component of the amount to be collected by the *Market Operator* from resource *cj* for *energy* transactions in the *WESM* at *dispatch interval i*
$ETA_{Congestion,pj,i}$	refers to the congestion component of the amount to be paid by the *Market Operator* to resource *pj* for *energy* transactions in the *WESM* at *dispatch interval i*
cj	refers to a resource with a collectible amount
CJ	refers to the set of all resources with collectible amounts
pj	refers to a resource with a payable amount
PJ	refers to the set of all resources with payable amounts

9.2.3 During *dispatch intervals* when there is no computed loss *trading amounts* or congestion *trading amounts*, the total *NSS* or *NSD* shall not be disaggregated and shall be allocated in accordance with Section 9.3.3. The total NSS or NSD shall be calculated as follows:

$$NSS_{NoMLC,MCC,i}/NSD_{NoMLC,MCC,i} = \sum_{cp \in CP} ETA_{cp,i} - \sum_{pp \in PP} ETA_{pp,i}$$

Where:

$NSS_{NoMLC,MCC,i}$	refers to the *net settlement surplus* when there is no computed loss *trading amounts* or congestion *trading amounts* at *dispatch interval i*

$NSD_{NoMLC,MCC,i}$	refers to the *net settlement deficit* when there is no computed loss *trading amounts* or congestion *trading amounts* at *dispatch interval i*
$ETA_{cp,i}$	refers to the amount to be collected by the *Market Operator* from *Trading Participant cp* for *energy* transactions in the *WESM* at *dispatch interval i*
$ETA_{pp,i}$	refers to the amount to be paid by the *Market Operator* to *Trading Participant pp* for *energy* transactions in the *WESM* at *dispatch interval i*
cp	refers to a Trading Participant with a collectible amount
CP	refers to the set of all Trading Participants with collectible amounts
pp	refers to a Trading Participant with a payable amount
PP	refers to the set of all Trading Participants with payable amounts

9.3 Recipients and Re-Distribution of Net Settlement Surplus and/or Net Settlement Deficit

9.3.1 *WESM Trading Participants* shall receive a share in the *net settlement surplus* due to losses based on their contribution to that amount. Similarly, *WESM Trading Participants* shall receive a share in the *net settlement surplus* due to congestion based on their contribution to that amount.

9.3.2 *WESM Trading Participants* shall pay a share in the *net settlement deficit* due to losses based on their contribution to that amount. Similarly, *WESM Trading Participants* shall pay a share in the *net settlement surplus* due to congestion based on their contribution to that amount.

9.3.3 Withdrawing *Trading Participants* shall receive or pay a share in the *net settlement surplus* or *net settlement deficit* during *dispatch intervals* when there is no computed loss *trading amounts* or congestion *trading amounts* in amounts pro-rated based on their portion of the total *gross energy settlement quantity* during that *dispatch interval*. For this purpose, withdrawing *Trading Participants* refer to the *Trading Participants* that have withdrawn energy for the relevant *dispatch interval.*

9.3.4 The total *net settlement surplus* and *net settlement deficit* allocation of a *WESM Participant* for a *dispatch interval* shall be calculated as follows:

$$\mathrm{NSS_{P,i}} = \sum_{\mathrm{j \in J_P}} \left(\mathrm{NSS_{Loss,j,i}} + \mathrm{NSS_{Congestion,j,i}}\right)$$

$$\mathrm{NSD_{P,i}} = \sum_{\mathrm{j \in J_P}} \left(\mathrm{NSD_{Loss,j,i}} + \mathrm{NSD_{Congestion,j,i}}\right)$$

or

$$\mathrm{NSS_{P,i}\ or\ NSD_{P,i}} = \sum_{\mathrm{j \in J_P}} \left(\mathrm{NSS_{NoMLC,MCC,j,i}\ or\ NSD_{NoMLC,MCC,j,i}}\right)$$

Where:

$NSS_{P,i}$	refers to the total *net settlement surplus* allocation of *trading participant* P for *dispatch interval* i
$NSD_{P,i}$	refers to the total *net settlement deficit* allocation of *trading participant* P for *dispatch interval* i
$NSS_{Loss,i,i}$	refers to the *net settlement surplus* allocation due to loss for *resource j* at *dispatch interval i*
$NSS_{Congestion,i,i}$	refers to the *net settlement surplus* allocation due to congestion for *resource j* at *dispatch interval i*
$NSD_{Loss,i,i}$	refers to the *net settlement deficit* allocation due to loss for *resource j* at *dispatch interval i*
$NSD_{Congestion,i,i}$	refers to the *net settlement deficit* allocation due to congestion for *resource j* at *dispatch interval i*
$NSS_{NoMLC,MCC,j,i}$	refers to the *net settlement surplus* allocation for *customer* resource *j* when there is no computed loss *trading amounts* or congestion *trading amounts* at *dispatch interval i*
$NSD_{NoMLC,MCC,j,i}$	refers to the *net settlement deficit* allocation for *customer* resource *j* when there is no computed loss *trading amounts* or congestion *trading amounts* at *dispatch interval i*
j	refers to a resource
J_P	refers to the set of all resources of *trading participant* P

9.3.5 The *net settlement surplus* or *net settlement deficit* shall be billed to *Direct WESM Members* including, but not limited to, the following entities:

a. *Distribution Utilities*;
b. *Suppliers*, including the Local RES and the Supplier of Last Resort (SoLR), and other electricity suppliers;
c. *Generation Companies*;
d. IPP Administrators; and
e. Other parties registered as *Direct WESM Members*.

9.3.6 The total *net settlement surplus* or *net settlement deficit* for every *billing period* shall be reflected immediately as a deduction to or an adjustment to the total *settlement amounts* of the *Direct WESM Member*, whether for its own *WESM* transactions or on behalf of its *Indirect WESM Member*. This shall be correspondingly re-distributed to the *end-users* at the retail level as part of the monthly generation rate pursuant to their corresponding power supply agreements approved by the *ERC*.

9.3.7 *Net settlement surplus* or *net settlement deficit* allocation corresponding to adjustment for transactions prior to the switching of an *Indirect WESM Member* to another *Direct WESM Member* shall be billed to the current *Direct WESM Member*.

9.3.8 Any *net settlement surplus* or *net settlement deficit* allocation billed to a *Supplier* shall be subject to re-distribution to its *contestable customers* pursuant to their Retail Supply Contract.

9.4 Flow Back of Net Settlement Surplus

9.4.1 The *net settlement surplus* due to losses shall be allocated to each *WESM Participant* based on each recipient's contribution to that amount. Similarly, the *net settlement surplus* due to congestion shall be allocated to each *WESM Participant* based on each recipient's contribution to that amount. If there is no calculated loss *trading amount* or congestion *trading amount*, the *net settlement surplus* shall be allocated on a pro-rata basis depending on each *customer* resource's share in the total *gross energy settlement quantity*.

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

$$NSS_{Loss,j,i}=\frac{LL_{spot,j,i}+LL_{LR,j,i}}{\sum_{j\in J}\left(LL_{spot,j,i}+LL_{LR,j,i}\right)}\times NSS_{Loss,i}$$

Where:

$NSS_{Loss,i,i}$	refers to the *net settlement surplus* allocation due to loss for *resource j* at *dispatch interval i*
$NSS_{Loss,i}$	refers to the *net settlement surplus* due to loss at *dispatch interval i*
$LL_{spot,j,i}$	refers to the surplus line loss payment for spot transaction of *resource j* at *dispatch interval i*
$LL_{LR,j,i}$	refers to the surplus line loss payment for line rental of *resource j* at *dispatch interval i*
J	refers to the set of all *resources*
j	refers to any *resource* of a *Trading Participant* paying line loss to which a pro-rated amount of the *net settlement surplus* due to loss will be returned

NSS due to congestion:

$$NSS_{Congestion,j,i}=\frac{CC_{spot,j,i}+CC_{LR,j,i}}{\sum_{j\in J}\left(CC_{spot,j,i}+CC_{LR,j,i}\right)}\times NSS_{Congestion,i}$$

Where:

$NSS_{Congestion,i,i}$	refers to the *net settlement surplus* allocation due to congestion for *resource j* at *dispatch interval i*
$NSS_{Congestion,i}$	refers to the *net settlement surplus* due to congestion at *dispatch interval i*
$CC_{spot,j,i}$	refers to the surplus congestion charge payment for spot transaction of *resource j* at *dispatch interval i*
$CC_{LR,j,i}$	refers to the surplus congestion charge payment for line rental of *resource j* at *dispatch interval i*
J	refers to the set of all *resources*
j	refers to any *resource* of a *Trading Participant* paying congestion charge to which a pro-rated amount of the *net settlement surplus* due to congestion will be returned

a. The line loss payment for spot transaction shall be determined as follows:

$$LL_{Spot,j,i}=\left[Max\left(GESQ_{j,i},BCQ_{j,i}\right)-BCQ_{j,i}\right]\times\left(MLC_{j,i}-GWAMLC_{i}\right)$$

Where:

$LL_{Spot,j,i}$	refers to the line loss payments for spot transaction of *resource j* at *dispatch interval i*
$GESQ_{j,i}$	refers to the *gross energy settlement quantity* of *resource j* at *dispatch interval i*
$BCQ_{j,i}$	refers to the total declared *bilateral contract quantity* to *resource j* at *dispatch interval i*
$MLC_{j,i}$	refers to the marginal loss cost of *resource j* at *dispatch interval i*
$GWAMLC_i$	refers to the generation-weighted marginal loss cost at *dispatch interval i*

b. The line loss payment associated with the line rental amounts for each *bilateral contract* declaration shall be determined as follows:

If the *trading participant* is the selling party of the *bilateral contract*:

$$\mathrm{LL_{LR,j,c,i}} = \sum\nolimits_{c \in C} \left[\mathrm{BCQ_{j,c,i}} \times \left(\mathrm{MAX}(\mathrm{GWAMLC_i}, \mathrm{MLC_{j,c,i}}) - \mathrm{MLC_{j,i}} \right) \right]$$

Where:

$LL_{LR,j,c,i}$	refers to the line loss payment for line rental associated with the *bilateral contract* to *resource j* with counterparty *c* at *dispatch interval i*
$BCQ_{j,c,i}$	refers to the declared *bilateral contract quantity* to *resource k* with counterparty *c* at *dispatch interval i*
$GWAMLC_i$	refers to the generation-weighted marginal loss cost at *dispatch interval i*
$MLC_{j,c,i}$	refers to the marginal loss cost of the reference node of the bilateral contract declaration to generator *resource k* with counterparty *c* at *dispatch interval i*
$MLC_{j,i}$	refers to the marginal loss cost of *resource j* at *dispatch interval i*
c	refers to the counterparty that *resource j* has a bilateral contract with
C	refers to the set of bilateral contract counterparties of *resource j*

If the trading participant is the buying party of the bilateral contract:

$$\mathrm{LL_{LR,j,c,i}} = \sum\nolimits_{c \in C} \left[\mathrm{BCQ_{j,c,i}} \times \left(\mathrm{MLC_{j,i}} - \mathrm{MAX}(\mathrm{GWAMLC_i}, \mathrm{MLC_{j,c,i}}) \right) \right]$$

Where:

$LL_{LR,j,c,i}$	refers to the line loss payment for line rental associated with the *bilateral contract* to *resource j* with counterparty *c* at *dispatch interval i*
$BCQ_{j,c,i}$	refers to the declared *bilateral contract quantity* to *resource j* with counterparty *c* at *dispatch interval i*
$GWAMLC_i$	refers to the generation-weighted marginal loss cost at *dispatch interval i*
$MLC_{j,c,i}$	refers to the marginal loss cost of the reference node of the bilateral contract declaration to *resource j* with counterparty *c* at *dispatch interval i*

$MLC_{j,i}$	refers to the marginal loss cost of *resource j* at *dispatch interval i*
c	refers to the counterparty that *resource j* has a bilateral contract with
C	refers to the set of bilateral contract counterparties of *resource j*

c. The congestion charge payment for spot transaction shall be determined as follows:

$$CC_{Spot,j,i} = [Max(GESQ_{j,i}, BCQ_{j,i}) - BCQ_{j,i}] \times (MCC_{j,i} - GWAMCC_{i})$$

Where:

$CC_{Spot,j,i}$	refers to the congestion charge payments for spot transaction of *resource j* at *dispatch interval i*
$GESQ_{j,i}$	refers to the *gross energy settlement quantity* of *resource j* at *dispatch interval i*
$BCQ_{j,i}$	refers to the total declared *bilateral contract quantity* to *resource j* at *dispatch interval i*
$MCC_{j,i}$	refers to the marginal congestion cost of *resource j* at *dispatch interval i*
$GWAMCC_{i}$	refers to the generation-weighted marginal congestion cost at *dispatch interval i*

d. The congestion charge payment associated with line rental payment for each *bilateral contract* declaration shall be determined as follows:

If the *trading participant* is the selling party of the *bilateral contract*:

$$CC_{LR,j,c,i} = \sum_{c \in C} [BCQ_{j,c,i} \times (MAX(GWAMCC_{i}, MCC_{j,c,i}) - MCC_{j,i})]$$

Where:

$CC_{LR,j,c,i}$	refers to the congestion charge payment for line rental associated with the *bilateral contract* to *resource j* with counterparty *c* at *dispatch interval i*
$BCQ_{j,c,i}$	refers to the declared *bilateral contract quantity* to *resource j* with counterparty *c* at *dispatch interval i*
$GWAMCC_{i}$	refers to the generation-weighted marginal congestion cost at *dispatch interval i*
$MCC_{j,c,i}$	refers to the marginal congestion cost of the reference node of the bilateral contract declaration to *resource j* with counterparty *c* at *dispatch interval i*
$MCC_{j,i}$	refers to the marginal congestion cost of *resource j* at *dispatch interval i*
c	refers to the counterparty that *resource j* has a bilateral contract with
C	refers to the set of bilateral contract counterparties of *resource j*

If the trading participant is the buying party of the bilateral contract:

$$CC_{LR,j,c,i} = \sum_{c \in C} [BCQ_{j,c,i} \times (MCC_{j,i} - MAX(GWAMCC_{i}, MCC_{j,c,i}))]$$

Where:

$CC_{LR,j,c,i}$	refers to the congestion charge payment for line rental associated with the *bilateral contract* to *resource j* with counterparty *c* at *dispatch interval i*
$BCQ_{j,c,i}$	refers to the declared *bilateral contract quantity* to *resource j* with counterparty *c* at *dispatch interval i*
$GWAMCC_i$	refers to the generation-weighted marginal congestion cost at *dispatch interval i*
$MCC_{j,c,i}$	refers to the marginal congestion cost of the reference node of the bilateral contract declaration to *resource j* with counterparty *c* at *dispatch interval i*
$MCC_{j,i}$	refers to the marginal congestion cost of *resource j* at *dispatch interval i*
c	refers to the counterparty that *resource j* has a bilateral contract with
C	refers to the set of bilateral contract counterparties of *resource j*

e. The line loss or congestion charge payment for spot transaction of a resource for a *dispatch interval* shall only be calculated if the *gross energy settlement quantity* of the resource is a negative value or any equivalent convention, which indicates a withdrawal of energy from the grid. Otherwise, the line loss or congestion charge payment for spot transaction of the resource for the *dispatch interval* shall be set to zero (0).

f. In case the line loss or congestion charge payment for spot transaction of a resource for a *dispatch interval* is a positive value or any equivalent convention, the line loss or congestion charge payment for spot transaction of the resource for that *dispatch interval* shall be set to zero (0).

g. Line loss or congestion charge payment for spot transaction will only be calculated if the *nodal energy dispatch price* of the resource was determined using the *market dispatch optimization model* in accordance with *WESM Rules* Clause 3.6.

h. In case the line loss or congestion charge payment for line rental payment of a bilateral contract declaration for a *dispatch interval* is a positive value or any equivalent convention, the line loss or congestion charge payment for line rental of the bilateral contract declaration for that *dispatch interval* shall be set to zero (0).

i. The GWAMLC and GWAMCC shall be calculated using the following formulas:

$$\mathrm{GWAMLC_i} = \frac{\sum_{k\in K}\left(\mathrm{MLC_{k,i}} \times \mathrm{EDS_{k,i}}\right)}{\sum_{k\in K}\mathrm{EDS_{k,i}}}$$

$$\mathrm{GWAMCC_i} = \frac{\sum_{k\in K}\left(\mathrm{MCC_{k,i}} \times \mathrm{EDS_{k,i}}\right)}{\sum_{k\in K}\mathrm{EDS_{k,i}}}$$

Where:

$GWAMLC_i$	refers to the generation-weighted marginal loss cost at *dispatch interval i*
$MLC_{k,i}$	refers to the marginal loss cost of *resource k* at *dispatch interval i*
$EDS_{k,i}$	refers to the *energy dispatch schedule* of resource *k* at *dispatch interval i*
$GWAMCC_i$	refers to the generation-weighted marginal congestion cost at *dispatch interval i*
$MCC_{k,i}$	refers to the marginal congestion cost of *resource k* at *dispatch interval i*
K	refers to the set of all generator resources with non-negative *energy dispatch schedule*

j. Only resources whose *nodal energy dispatch price* of the resource was determined using the *market dispatch optimization model* in accordance with *WESM Rules* Clause 3.6 and has a non-negative *energy dispatch schedule* will be included in the calculation of *GWAMLC* and *GWAMCC*.

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. *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:

$$\mathrm{NSS_{NoMLC,MCC,j,i}} = \frac{\mathrm{GESQ_{j,i}}}{\sum_{j \in J} \mathrm{GESQ_{j,i}}} \times \mathrm{NSS_{NoMLC,MCC,i}}$$

Where:

$NSS_{NoMLC,MCC,j,i}$	refers to the *net settlement surplus* allocation when there is no computed loss *trading amounts* or congestion *trading amounts* for *customer* resource *j* at *dispatch interval i*
$NSS_{NoMLC,MCC,i}$	refers to the *net settlement surplus* when there is no computed loss *trading amounts* or congestion *trading amounts* at *dispatch interval i*
$GESQ_{j,i}$	refers to the *gross energy settlement quantity* of *customer* resource *j* at *dispatch interval i*
j	refers to a customer resource
J	refers to the set of all *customer* resources with negative *gross energy settlement quantities*

9.5 **Flow Back of Net Settlement Deficit**

9.5.1 The *net settlement deficit* due to losses shall be allocated to each *WESM Participant* based on each recipient's contribution to that amount. Similarly, the *net settlement* *deficit* due to congestion shall be allocated to each *WESM Participant* based on each recipient's contribution to that amount.

9.5.2 The amount to be paid shall be equal to the ratio of the recipient's deficit loss or congestion payments to the total deficit loss or congestion payments of all recipients multiplied by the total *net settlement deficit* amount due to loss or congestion, respectively, as represented by the following formula:

NSD due to loss:

$$NSD_{Loss,j,i} = \frac{LL_{spot,j,i} + LL_{LR,j,i}}{\sum_{j \in J}\left(LL_{spot,j,i} + LL_{LR,j,i}\right)} \times NSD_{Loss,i}$$

Where:

$NSD_{Loss,i,i}$	refers to the *net settlement deficit* allocation due to loss for *resource j* at *dispatch interval i*
$NSD_{Loss,i}$	refers to the *net settlement deficit* due to loss at *dispatch interval i*
$LL_{spot,j,i}$	refers to the deficit line loss payment for spot transaction of *resource j* at *dispatch interval i*
$LL_{LR,j,i}$	refers to the deficit line loss payment for line rental of *resource j*
J	refers to the set of all *resources*
j	refers to any *resource* of a *Trading Participant* paying line loss to which a pro-rated amount of the *net settlement deficit* due to loss will be allocated

NSD due to congestion:

$$NSD_{Congestion,j,i} = \frac{CC_{spot,j,i} + CC_{LR,j,i}}{\sum_{j \in J}\left(CC_{spot,j,i} + CC_{LR,j,i}\right)} \times NSD_{Congestion,i}$$

Where:

$NSD_{Congestion,i,i}$	refers to the *net settlement deficit* allocation due to congestion for *resource j* at *dispatch interval i*
$NSD_{Congestion,i}$	refers to the *net settlement deficit* due to congestion at *dispatch interval i*
$CC_{spot,j,i}$	refers to the deficit congestion charge payment for spot transaction of *resource j* at *dispatch interval i*
$CC_{LR,j,i}$	refers to the deficit congestion charge payment for line rental of *resource j* at *dispatch interval i*
J	refers to the set of all *resources*
j	refers to any *resource* of a *Trading Participant* paying congestion charge to which a pro-rated amount of the *net settlement surplus* due to congestion will be allocated

a. The line loss or congestion charge payment for spot transaction of a resource for a *dispatch interval* shall only be calculated if the *gross energy settlement quantity* of the resource is a negative value or any equivalent convention, which indicates a withdrawal of energy from the grid. Otherwise, the line loss or congestion charge payment for spot transaction of the resource for the *dispatch interval* shall be set to zero (0).

b. The line loss or congestion charge payment for spot transaction of a resource shall be calculated in accordance with Section 9.4.2(a) and (c). In case the line loss or congestion charge payment for spot transaction of a resource for a *dispatch interval* is a negative value, the line loss or congestion charge payment for spot transaction of the resource for that *dispatch interval* shall be set to zero (0).

c. Line loss or congestion charge payment for spot transaction will only be calculated if the *nodal energy dispatch price* of the resource was determined using the *market dispatch optimization model* in accordance with *WESM Rules* Clause 3.6.

d. The line loss or congestion charge payment associated with line rental payment of a bilateral contract declaration shall be calculated in accordance with Section 9.4.2(b) and (d). In case the line loss or congestion charge payment for line rental of a bilateral contract declaration for a *dispatch interval* is a negative value or any equivalent convention, the line loss or congestion charge payment for line rental of the bilateral contract declaration for that *dispatch interval* shall be set to zero (0).

e. The GWAMLC and GWAMCC shall be calculated in accordance with Section 9.4.2(h) and (i).

9.5.3 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 deficit* 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*.-*Generator* resources shall not have an allocation of the *net settlement deficit* 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 deficit* amount, as represented by the following formula:

$$\mathrm{NSD}_{\mathrm{NoMLC,MCC,j,i}} = \frac{\mathrm{GESQ}_{\mathrm{j,i}}}{\sum_{\mathrm{j \in J}} \mathrm{GESQ}_{\mathrm{j,i}}} \times \mathrm{NSD}_{\mathrm{NoMLC,MCC,i}}$$

Where:

$NSD_{NoMLC,MCC,j,i}$	refers to the *net settlement deficit* allocation when there is no computed loss *trading amounts* or congestion *trading amounts* for *customer* resource *j* at *dispatch interval i*
$NSD_{NoMLC,MCC,i}$	refers to the *net settlement deficit* when there is no computed loss *trading amounts* or congestion *trading amounts* at *dispatch interval i*
$GESQ_{j,i}$	refers to the *gross energy settlement quantity* of *customer* resource *j* at *dispatch interval i*
j	refers to a customer resource
J	refers to the set of all *customer* resources with negative *gross energy settlement quantities*

9.6 **Submission of Report to the ERC**

9.6.1 The *Market Operator* shall comply with the reportorial requirements:

a. Regular monthly summary reports on the amount of NSS or NSD distributed to each *Trading Participant.* This report shall be made available to all *Market Participants* and shall be *published* in the *market information website.* A verified copy of the report shall likewise be submitted to the *ERC,* including report on the contributors to and reasons for the surplus or deficit, no later than ninety (90) *business days* from the last day of the *billing period* covered by the monthly summary report. The corresponding Value Added Tax (VAT) and interest amounts, as well as the date in which the interests were earned or credited to *the Market Operator,* if any, shall similarly be included in the subject monthly summary report;

b. The pertinent data covered by the subject monthly summary report shall also be submitted in MS Excel format; and

c. The annual report on the NSS or NSD calculation and allocation shall be submitted no later than the 30th day of May immediately following the year in review, comparing the subject year and the preceding year's NSS levels and allocations, and analysis of the factors and constraints giving rise to any NSS or NSD. This report shall also be submitted to the market participants and to the *PEM Board*.

9.6.2 The *Market Operator* shall comply with Clause 5.2.6 of the *WESM Rules* which requires, among others, the conduct of a *spot market* audit covering such items as enumerated under Clauses 5.2.6.1 to 5.2.6.4 of the *WESM Rules*. The audit shall also include the actual calculation of *NSS* or *NSD, its breakdown into NSS or NSD due to loss and congestion,* and its allocation, corresponding VAT and interest amounts, as well as the actual billing and collection.

9.6.3 Such audit shall be conducted by a qualified third-party auditor, and a quarterly report resulting therefrom shall be submitted to the *ERC* no later than ninety (90) *business days* after the *billing period* in review.

9.7 **Interests**

9.7.1 Should the *Market Operator* be unable to return the amount of the *NSS* due to be flowed back to appropriate *WESM Participants* under these Rules during the period specified, the retained amount shall be imposed an interest at the rate of the prevailing 91-day Treasury Bill rate as published by the Bangko Sentral ng Pilipinas (BSP) plus 300 basis points, the return of which shall be in accordance with Article IV of *ERC* Resolution No. 07 Series of 2019. Such interest shall not be passed on to the market participants.

9.7.2 The *DUs* and *RES*, which are recipients of *NSS* but are not complied with the re-distribution process under these rules during the period specified shall be subject to the interest at the rate of the prevailing 91-day Treasury Bill rate as published by the BSP plus 300 basis points, the return of which shall be in accordance with Article 4 of *ERC* Resolution No. 07 Series of 2019. The subject interest shall be on account of *DUs* and *RES* and shall not be passed on their respective customers.

9.8 **Penalties**

9.8.1 A penalty ranging from One Hundred Thousand Pesos (Php 100,000.00) to a maximum of Fifty Million Pesos (Php 50,000,000.00) shall be imposed on the following acts:

a. Failure to correctly implement NSS Rules, as amended, including the NSS or NSD formula;
b. Failure to submit documentary requirements as required under these rules;
c. Failure to conduct audits of the Market Operations and the settlement systems and the other procedures, persons, systems or other matters relevant to the spot market as required under Section 1.5.2 of the WESM Rules and Section, Article VII of ERC Resolution No. 07 Series of 2019.
d. Non-submission or failure to submit on a timely basis, the required reports as provided in Article VII of ERC Resolution No. 07 Series of 2019;
e. Failure to act on and resolve adverse findings of NSS audit within ninety (90) days upon receipt by the ERC of the subject Quarterly Audit Report;
f. Submission of inaccurate NSS and other related data;
g. Unauthorized disclosure of NSS data; and
h. Failure to comply with the directives of the Commission pertinent to the implementation of the NSS Rules, as amended.

9.8.2 The penalties stated in the preceding section shall be without prejudice to any civil, administrative, and criminal action that may be filed against the violation/s of these Rules.

SECTION 10 AMENDMENT, PUBLICATION AND EFFECTIVITY

10.1 **Review and Update**

10.1.1 The Market Operator shall review and update this Market Manual, as necessary.

10.1.2 Any amendment 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.

10.1.3 After the *DOE's* promulgation, the *PEMC* shall file with the *ERC* for the final approval of the pricing and settlement provisions of this *Market Manual*.

10.2 **Publication and Effectivity**

The publication and effectivity of this *Market Manual* shall be in accordance with the resolution of the *ERC*.

10.3 **Provisions Prior to Interconnection of Mindanao**

For *WESM settlements* to reflect the actual physical transactions in Luzon, Visayas, and Mindanao, calculations and procedures on administered price determination methodology and *net settlement surplus* as identified in Appendix C shall be performed per settlement region until the interconnection of Luzon/Visayas and Mindanao.

SECTION 11 APPENDICES

APPENDIX A – DETAILED MATHEMATICAL FORMULATION

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SECTION 1 OPTIMIZATION OBJECTIVE

The optimization objective fits the least-cost multi-product co-optimization methodology that maximizes economic efficiency and relieves *network congestion* while respecting physical constraints. The mathematical formulation is minimization of market payments which in equivalent form can be expressed as maximization of the economic value of dispatched load.

1.1. Maximization of *Economic Gain*

1.1.1. Maximum economic efficiency of the system operation can be achieved through the least-cost *security constrained dynamic dispatch* (SCDD) with co-optimization of multiple electricity commodities.

1.1.2. *Energy* and *reserve* costs present integrated *bid* and *offer* price curves. The price curves are stepwise functions of procured services, therefore costs are piecewise linear functions of service quantities. With price curves being stepwise, the objective function of *Economic Gain* can be expressed as the objective function in Section 4.4 of the Price Determination Methodology *Market Manual*.

1.1.3. The maximization of the overall system costs can be expressed as an SCDD problem with the following optimization objective function in generalized form:

$\max\limits_{En,AS}\{$ Co-optimization objective as maximization of the *Economic Gain*:

$-\sum_{t\in T}(\rho^t \cdot \sum_{unit\in G} C_{unit}^{En;t}(En_{unit}^t))$	- *Energy offer* costs
$-\sum_{t\in T}(\rho^t \cdot \sum_{unit\in G}(C_{unit}^{RegRaise;t}(Reg_{unit}^{Raise;t}) + C_{unit}^{RegLower;t}(Reg_{unit}^{Lower;t})))$	- Regulation Raise and Regulation Lower *offer* costs
$-\sum_{t\in T}(\rho^t \cdot \sum_{unit\in G} C_{unit}^{FFCS;t}(FFCS_{unit}^t))$	- Contingency *offer* costs
$+\sum_{t\in T}(\rho^t \cdot \sum_{unit\in L} C_{load}^{En;t}(En_{load}^t))$	- *Load bid* income
$-\sum_{t\in T}(\rho^t \cdot \sum_{load\in L} C_{load}^{curt})$	- *Load* curtailment costs
$-\sum_{t\in T}(\rho^t \cdot \sum_{constr\in Constra\,int\,Set} C_{constr}^{vio}(CV_{constr}^t))\quad\}$	- Constraint violation costs

In this formulation, cost terms are related with *Offers* while *Bids* are treated as income – i.e. *Offer* price terms have negative sign in objective.

1.1.4. *Self-scheduled energy* is incorporated into *bid* and *offer* limits during optimization by respective price/quantity pairs (PQ segments), where the quantity is the self-scheduled value, while the price is reflective of the prioritization price for the particular self-schedule type (i.e. schedule priority). Prices are negative for *offer* self-schedules (i.e. projected *generation*) and positive for *bid* self-schedules (i.e. forecasted *load* quantities).

1.2. Minimization of Market Payments

1.2.1. The formulation in Section 1.1 is equivalent to the Objective Function defined as minimization of Market Payments, where the same terms are used but with opposite signs. Equivalent minimization form can be expressed as:

$\min\limits_{En,AS}\{$ Least-cost co-optimization objective as minimization of market payments:

$+\sum_{t\in T}(\rho^t \cdot \sum_{unit\in G} C_{unit}^{En;t}(En_{unit}^t))$	- *Energy offer* costs

$+\sum_{t\in T}(\rho^t \cdot \sum_{unit\in G}(C_{unit}^{RegRaise;t}(Reg_{unit}^{Raise;t}) + C_{unit}^{RegLower;t}(Reg_{unit}^{Lower;t})))$ - Regulation Raise and Regulation Lower *offer* costs

$+\sum_{t\in T}(\rho^t \cdot \sum_{unit\in G} C_{unit}^{FFCS;t}(FFCS_{unit}^t))$ - Contingency *offer* costs

$-\sum_{t\in T}(\rho^t \cdot \sum_{unit\in L} C_{load}^{En;t}(En_{load}^t))$ - *Load bid* income

$+\sum_{t\in T}(\rho^t \cdot \sum_{load\in L} C_{load}^{curt})$ - *Load* curtailment costs

$+\sum_{t\in T}(\rho^t \cdot \sum_{constr\in Constra\,int\,Set} C_{constr}^{vio}(CV_{constr}^t))\quad\}$ - Constraint violation costs

Where:

$\rho^t = \frac{\Delta_t}{60}$ is market time interval length (Δ_t) expressed as fraction of one hour (60 minutes)

C_{constr}^{vio} is constraint violation cost at time interval t

CV_{constr}^t is constraint violation quantity at time interval t

SECTION 2 SYSTEM CONSTRAINTS

The main operational system requirements consist of power balance, contingency reserves requirements and regulation capability requirements. In addition, *transmission network* power flow *constraints* (base case and *contingency* cases) are also considered System *Constraints*.

2.1. System Power Balance

2.1.1. The system power balance is a common requirement for all short-term forward markets forcing the system power balance at each trading time interval. The shadow cost of *load* balance presents *system marginal price* for *energy* and also detects unit that is system marginal.

2.1.2. System power balance can be expressed as an equality equation with difference between variable *supply* and variable *demand* (price sensitive or curtailable) on one side and firm (forecasted) *demand* and losses on the other side.

$$\sum_{unit\in G} En_{unit}^t - \sum_{load\in L} En_{load}^t = En_{req}^t + En_{loss}^t\ ;\ t\in T$$

2.1.3. In its formulation, the power balance is extended for slack variables for under-generation and over-generation condition as:

$$\sum_{unit\in G} En_{unit}^t - \sum_{load\in L} En_{load}^t + Q_{UG} = En_{req}^t + En_{loss}^t + Q_{OG}\ ;\ t\in T$$

Where:

Q_{UG} and Q_{OG} are slack variables for under and over *generation*.

2.1.4. As the *generation* and *load* terms are function of *bid*/*offer* quantities, the power balance equation can be written as:

$$\sum_i \sum_j G_{i,j} + Q_{UG} = \sum_i DB_i + \sum_a P_{Loss,a} + Q_{OG}$$

Where:

$\sum_a P_{Loss.a}$ is the sum of all transmission losses in the system and the *generation offer* quantities and *load bid* quantities (G and DB variables) include projected *generation* and forecasted *load* terms, respectively.

This is somewhat a simplified formulation, where the whole system is connected by electrically contiguous AC *network* and there are no export/imports to the system.

2.1.5. The *network energy* losses are linearized using incremental loss factors around the base operating point in respect to *generators* and *loads*:

$$En_{loss}^{t} = En_{loss}^{base;t} + \Delta En_{loss}^{t};\ t \in T$$

Where:
$\Delta En_{loss}^{t} = \sum_{unit \in G} \alpha_{node}^{t} \cdot (En_{unit}^{t} - En_{unit}^{base;t}) - \sum_{load \in L} \alpha_{node}^{t} \cdot (En_{load}^{t} - En_{load}^{base;t})\ ;\ t \in T.$

2.1.6. The *energy* requirement can present the sum of fixed *loads* and *generations*, system *load forecast* or actual *energy* imbalance. The *market network model* provides for a mix of self-scheduled and offered *generation* on *supply* side and a mix of forecasted nodal *load* and *load bids* on *demand* side.

2.1.7. *Load offers* are considered to represent delivered *load*. The market *energy* balance can be expressed in terms of loss penalty factors and uninterruptible market *energy* requirement as:

$$\sum_{unit \in G} En_{unit}^{t}/pf_{unit}^{t} - \sum_{load \in L} En_{load}^{t}/pf_{load}^{t} = En_{req}^{t} + \Delta En_{req}^{t};\ t \in T$$

Where:

$$\Delta En_{req}^{t} = En_{loss}^{base;t} - \sum_{unit \in G} \alpha_{node}^{t} \cdot En_{unit}^{base;t} + \sum_{load \in L} \alpha_{node}^{t} \cdot En_{load}^{base;t}\ ;\ t \in T$$

and loss penalty factors are calculated as follows:
$pf_{unit}^{t} = 1/(1 - \alpha_{node}^{t})$ and $pf_{load}^{t} = 1/(1 + \alpha_{node}^{t})$
Utilizing the notation given in Appendix A.1, namely, $\alpha_{node}^{t} = \frac{\partial P_{loss}^{t}}{\partial P_{node}}$ the loss penalty factor term can be written in the form: $pf_{unit}^{t} = \frac{1}{(1 - \frac{\partial P_{loss}^{t}}{\partial P_{node}})}$
pf_{unit}^{t} is also referred to as the *transmission loss factor* (TLF).

Islanded Operation

2.1.8. In accordance to the centralized concept of the system operation, only a single system wide power balance is considered. However, in case of electric islanding condition, or when parts of electric grid are connected only by *HVDC* links, a separate *load* balance equation will be applied for each energized electrical island.

2.1.9. There will be mapping of *nodes* (*loads* and *generators*) to islands. Based on that mapping, SCDD will formulate *load* balance equation for each island. Accordingly, *shadow price* on the relevant *energy* balance constraint will be calculated for each electrical island. In case of islanding, there is no system level power balance but each region has its own power balance equation.

2.1.10. For each electrical island *i* the following equation will be written for a given time interval *t:*

$$\sum_{unit \in Gi} En_{unit}^{t} - \sum_{load \in Li} En_{load}^{t} + Q^{i}{}_{UG} = En_{req}^{i,t} + En_{loss}^{i,t} + Q^{i}{}_{OG} \ ; \ t \in T$$

2.1.11. During the islanding condition, congestion in one island does not affect the congestion of other islands. Losses are also calculated per island.

2.1.12. In scenario where *grids* are connected only by *HVDC* link, additional terms presenting DC pole injections for each *HVDC* link *dc* connected to particular grid *i* will show in each grid *i load* balance.

$$\sum_{unit \in Gi} En_{unit}^{t} - \sum_{load \in Li} En_{load}^{t} + \sum_{dc \in HVDCi} En_{dc}^{t} + Q^{i}{}_{UG} = En_{req}^{i,t} + En_{loss}^{i,t} + Q^{i}{}_{OG} \ ; \ t \in T$$

Term En_{dc}^{t} is positive for *HVDC* imports and negative for *HVDC* exports.

2.2. Regional Reserve Requirements

2.2.1. The *reserve requirements* can be specified for each *reserve region*. *Reserve regions* are the same for all *reserves* and for all time intervals. Nevertheless, separate requirements can be specified for each *reserve region*, each *reserve category* and each scheduling time interval. The overall system is treated as a *reserve region.*

Regulation Raise and Regulation Lower Reserve Requirements

2.2.2. The regulation capability is provided through the regulation capacity market segment. Separate minimal requirements for Regulation Raise capacities:

$$\underline{Reg}_{ASreq}^{Raise;t} \leq \sum_{unit \in AS} Reg_{unit}^{Raise;t} \ ; \ t \in T$$

and maximal and minimal requirements for Regulation Lower capacities:

$$\underline{Reg}_{ASreq}^{Lower;t} \leq \sum_{unit \in AS} Reg_{unit}^{Lower;t} \leq \overline{Reg}_{ASreq}^{Lower;t} \ ; \ t \in T$$

2.2.3. Only online generating units can be awarded regulation service to contribute to the regional regulation requirements.

2.2.4. The Regulating reserve requirements equations also include slack variables for insufficient regulating reserve.

Contingency Reserve Requirements

2.2.5. Analogously to Regulating Reserve Raise and Regulating Reserve Lower minimal requirements, regional minimum requirements can be specified for other ancillary services (AS) and for each time interval:

$$\underline{Res}_{ASreq}^{t} \leq \sum_{unit \in AS} Res_{unit}^{t} \;\; ; \; t \in T$$

2.2.6. The Contingency Reserve requirements equations also include slack variables for insufficient contingency reserve.

2.3. Nodal Energy Balance

2.3.1. The power withdrawn for each nodal load's schedule is equivalent to the power transferred to this nodal load from the power grid.

2.4. Reserve provider capacity caps

2.4.1. Reserve Provider capacity caps are group *constraints*, where an aggregated award may be less than or equal to a specified value. Capacity caps are defined per:

a. Ancillary Service provider (Market Participant)
b. Class of Ancillary Service providers

2.4.2. In both cases the equation can be written as:

$$\textstyle\sum_{unit \in AS\ Group} Res_{unit}^{t} \leq \overline{Res}_{AS;\ AS\ Group}^{t} \;\; ; \; t \in T,$$

Where AS Group can be each affected AS provider or AS provider class.

2.5. AC Power Flow Model

2.5.1. Accurate power flow results presenting physical system operation are essential for market operation. The power balance equations for some *network node k* having incident *nodes* m can be specified in the following form:

$$\boldsymbol{P_{node}^{k} = V_{node}^{k} \sum_{m \in I_k} V_{node}^{m} [G_{line}^{km} \cos(\theta_{node}^{k} - \theta_{node}^{m}) + B_{line}^{km} \sin(\theta_{node}^{k} - \theta_{node}^{m})]}$$

$$\boldsymbol{Q_{node}^{k} = V_{node}^{k} \sum_{m \in I_k} V_{node}^{m} [G_{line}^{km} \sin(\theta_{node}^{k} - \theta_{node}^{m}) - B_{line}^{km} \cos(\theta_{node}^{k} - \theta_{node}^{m})]}$$

2.5.2. The AC power flow equations completely determine the *network* operating state and their solution $[V_{node}^{k;base}; \theta_{node}^{k;base}]$ is calculated for all *network nodes*.

2.5.3. This solution is considered as the base *network* state. All nodal power flow injections, line power flows and *network* losses are calculated for the base *network* state. Additionally *network energy* loss sensitivities and *transmission line* shift factors are calculated to provide a linearized AC model for the *network* base state.

2.5.4. The AC power flow respects unit MW limits, MVAR limits, scheduled voltages for local voltage controlled buses and limits on shunt capacitor banks, load tap changer (LTC) taps and phase-shifter taps.

2.5.5. In cases when nodal *loads* include losses the AC power flow uses *load* distribution slack to allocate *network energy* losses. The adjusted *load* schedules present the delivered nodal *loads* corresponding to the *generation* schedules. If *load* schedules present delivered *load* themselves then *network energy* losses are distributed to the *generation* schedules.

Network Loss Model

2.5.6. Summing up all AC power flow nodal balance equations, including *network energy* losses, the system power balance equation in terms of nodal *generation* and *load* schedules is obtained:

$$\sum_{node\in G} P_{node}^{base;t} - \sum_{node\in L} P_{node}^{base;t} = \sum_{node\in G\cup L} P_{node}^{fix;t} + P_{loss}^{base;t}(P_G^{base;t}, P_L^{base;t})\ ;\ t\ \in T$$

2.5.7. Both *generation* and *load* nodal power injections are expressed as positive values. At the same time, the nodal loss sensitivity factors are calculated as derivatives of *network energy* losses in respect to *generation* nodal power injections. Therefore, the *load* sensitivity loss factors are equal to the negative *generation* nodal loss factors.

2.5.8. The loss sensitivity factors are calculated using a reference bus approach. The resulting linearized model for *network* losses can be specified as follows:

$$P_{loss}^t(P_G^t, P_L^t) = P_{loss}^t\left(P_G^{base;t}, P_L^{base;t}\right) + \sum_{node\in G} \alpha_{node}^t \cdot \left(P_{node}^t - P_{node}^{base;t}\right) - \sum_{node\in L} \alpha_{node}^t \cdot \left(P_{node}^t - P_{node}^{base;t}\right)\ ;\ t \in T$$

Line Power Flow Limits

2.5.9. Transmission branches/paths congested due to *energy* schedules are considered for both the base case and *contingency* cases. The branch flow MVA limits are translated into MW limits, making the assumption that MVAR branch flows and voltage magnitudes do not change significantly due to active power rescheduling. The MW line flow limits are calculated as:

$$\boldsymbol{\overline{P}_{line}^{t} = SQRT(\overline{MVA}_{line}^{t} ** 2 - Q_{line}^{b;t} ** 2);\quad t \in T.}$$

2.5.10. The *transmission line* flows are expressed as linearized functions of the nodal power injections around the base operating state using calculated Shift Factors:

$$P_{line}^t = P_{line}^{base;t} + \sum_{node\in N} SF_{line}^{node} \cdot (P_{node}^t - P_{node}^{base;t})\ ;\ line\ \in N;\ t\ \in T$$

2.5.11. The branch power flows of critical *transmission lines* are limited in both directions:

$$\boldsymbol{\underline{P}_{line}^t \le P_{line}^t \le \overline{P}_{line}^t;\quad line \in N;\quad t \in T}$$

2.5.12. When solving the base case the limit used is the Normal limit. When a *contingency* case is being solved, the flows are checked against the *Contingency* limit. It is required that the *Contingency* limit be the same or greater than the Normal limit.

2.5.13. The set of critical transmission lines is selected according to the percentage of line MW loading. The lines loaded above the specified threshold are included.

2.5.14. The branch power flows equations also include segmented slack variables for limit violation.

2.6. Constraints on HVDC operation

2.6.1. The *HVDC* operation in the optimization problem is modeled by introduction of the concept of *HVDC* Resource. *HVDC* Resource is a modeling vehicle to represent the flow MW and flow direction on the *HVDC* line, as well as other *HVDC* operational *constraints*, like the minimum time required to change the flow direction. The *HVDC* Resource MW schedule (injection) is also representing *network* injection or withdrawal for AC *network* at the DC terminal. The model is illustrated below.

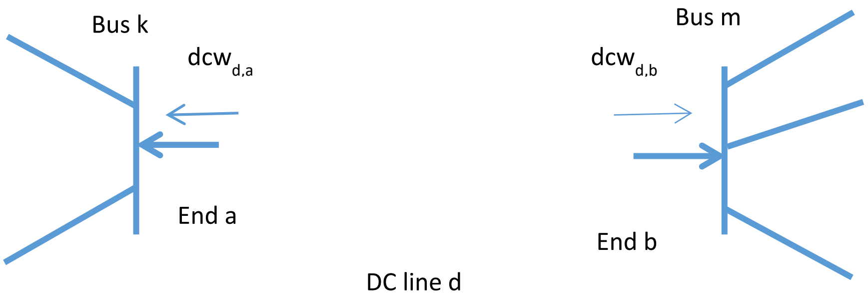

Figure 1: HVDC model

In Figure 1, the DC line *d* goes between the AC buses *k* and *m*. An assignment of ends has been done as End *a* and End *b*. Assume that End *a* is the end where interchange schedules are assumed to flow. This figure shows the model that is implemented in the optimization problem formulation, where the DC line itself has been replaced by a coordinated pair of DC injections.

$dcw_{d,a}^{t}$ This is the MW flow on end *a* of the DC line *d* at time *t*. The sign convention is that flow from the DC line into the AC system is considered negative.

$dcw_{d,b}^{t}$ This is the MW flow on end *b* of the DC line *d* at time *t.* The sign convention is that flow from the DC line into the AC system is considered negative.

2.6.2. In its operation, *HVDC* Resource on both ends of a DC Link can act both as a generator and a *load*, with *HVDC* having three discrete state of operation: no-flow, flow in prevailing direction and flow in direction opposite to the prevailing direction. The MW schedules to the *HVDC* Resources are included in *Load* Balance of each of the electrical islands connected by DC Link. They are also included in *HVDC* flow equation that accounts for losses as described below.

2.6.3. A default DC loss percentage is used to obtain a simplified formulation of DC Link *load* balance.

When the flow is from end *b* to end *a*:

$$\mathrm{dcw}_{\mathrm{d,b}}^{\mathrm{t}} + \mathrm{dcw}_{\mathrm{d,a}}^{\mathrm{t}} - \mathrm{dcwlossp}_{\mathrm{d,b,a}}/100 \cdot \left(\mathrm{dcw}_{\mathrm{d,b}}^{\mathrm{t}}\right) = 0$$

When the flow is from end *a* to end *b*:

$$\mathrm{dcw}_{\mathrm{d,b}}^{\mathrm{t}} + \mathrm{dcw}_{\mathrm{d,a}}^{\mathrm{t}} - \mathrm{dcwlossp}_{\mathrm{d,b,a}}/100 \cdot \left(\mathrm{dcw}_{\mathrm{d,a}}^{\mathrm{t}}\right) = 0$$

Where:

$dcwlossp_{d,b,a}$ is the default loss percentage.

There are no slack variables associated with above equations. Note that $dcw_{d,a}^{t}$ and $dcw_{d,b}^{t}$ variables are unbounded, but subject to DC MW Flow *constraints*. In case of zero losses, above equations essentially state that the DC Link transfer at End *b* is the same as transfer at End *a* by absolute value, but with opposite sign.

If the presence of DC link is the only electrical connection between AC *networks* at End *a* and End *b*, then those *networks* are considered to be separate AC islands, so the network injections at one island do not have shift factors with respect to the AC flow *constraints* in another island.

Directional HVDC Limit

2.6.4. Directional flow *constraints* flow on DC line to be between minimum and maximum flow limit for each direction (if the flow is non zero).

When the flow is from End *a* to End *b*, the constraint is:

$$\underline{HVDC_{d,a}^{t}} \leq dcw_{d,a}^{t} \leq \overline{HVDC_{d,a}^{t}}$$

When the flow is from End *b* to End *a*, the constraint is:

$$\underline{HVDC_{d,b}^{t}} \leq -dcw_{d,a}^{t} \leq \overline{HVDC_{d,b}^{t}}$$

Where:

$\overline{HVDC_{d,a}^{t}}$ and $\underline{HVDC_{d,a}^{t}}$ are maximum and minimum MW flow limit (positive values) when flow is from *a* to *b*

$\overline{HVDC_{d,b}^{t}}$ and $\underline{HVDC_{d,b}^{t}}$ are maximum and minimum MW flow limit (positive values) when flow is from *b* to *a*

2.6.5. Additional binary variables are introduced to enforce directional limits. One binary variable is used to model flow from End *a* to End *b* and another binary variable is introduced to model flow from End *b* to End *a*. When DC transfer variable $dcw_{d,a}^{t}$ is positive, then the binary variable $dcd_{d,a}^{t}$ has to be one and the binary variable $dcd_{d,b}^{t}$ has to be zero. Analogously in case when $dcw_{d,a}^{t}$ is negative. In case that $dcw_{d,a}^{t}$ is itself zero, both binary variables have to be zero as well. The upper and lower directional limit on *HVDC* flow can be formulated as:

$$dcw_{d,a}^{t} \leq \overline{HVDC_{d,a}^{t}} * dcd_{d,a}^{t} - \underline{HVDC_{d,b}^{t}} * dcd_{d,b}^{t}$$

$$dcw_{d,a}^{t} \geq \underline{HVDC_{d,a}^{t}} * dcd_{d,a}^{t} - \overline{HVDC_{d,b}^{t}} * dcd_{d,b}^{t}$$

$$dcd_{d,a}^{t} + dcd_{d,b}^{t} \leq 1$$

Where:

$dcd_{d,a}^{t}$ is a binary variable determining whether the MW flow is from end *a* to end *b* at time interval *t*
$dcd_{d,b}^{t}$ is a binary variable determining whether the MW flow is from end *b* to end *a* at time interval *t*

2.6.6. The *HVDC* Flow limit equations are soft *constraints* and include slack variables for limit violation, both for minimum and maximum flow limit, and in both directions.

Minimum time needed for HVDC change of flow

2.6.7. Additional constraint applicable to *HVDC* line is the "change of flow direction" constraint. It is described by the minimum time that has to lapse before a power flow on DC line can flow in the opposite direction. Constraint is modeled as form of a minimum down time constraint, i.e. the minimum time *HVDC* Line has to spend in zero flow condition.

2.6.8. The constraint is enforced by the following equations:

$$\sum_{t=t1}^{t1+T_d^{MIN}} dct_{d,a}^{t} \geq T_d^{MIN}$$

$$dct_{d,a}^{t} = 1 - (dcd_{d,a}^{t} + dcd_{d,b}^{t})$$

That are effective for every interval *t1* where the flow changed to zero from being non-zero; i.e.

$$dct_{d,a}^{t1} - dct_{d,a}^{t1-1} = 1$$

Where:

$dct_{d,a}^{t}$ is a helper variable showing that the flow on the DC line is zero at time interval *t*
T_d^{MIN} is the minimum time before the DC line flow can be reversed

2.6.9. In addition to above equations there are boundary conditions considering past as follows:

$dct_{d,a}^{t}$ Variable has counter reflecting the initial condition, i.e. if there is a change of flow to zero from non-zero that occurred in the past, that interval is recorded and the counter is incremented each *real time dispatch* run, while in each subsequent *real time dispatch* run the following is enforced:

$$dct_{d,a}^{t} = 1 \; \forall \; t \leq MAX(0, T_d^{MIN} - t_0)$$

Where:

t_0 is the number of intervals since the flow was last changed from non-zero to zero in the past *real time dispatch* runs.

2.6.10. The change of flow *constraints* are hard *constraints* and cannot be violated in the model. In the case when the *HVDC* line flow direction change is pre-scheduled, the minimum switching time is modified to comply with the schedule (i.e. the line flow direction change schedule is always considered to be feasible).

SECTION 3 BID/OFFER RELATED CONSTRAINTS

The electric *energy* related products are provided from physical resources with limited capacities. In addition to limited amount of available products separately, the capacity limits for resources providing multiple products are included into optimization model. Therefore, the model includes the following limitations for each physical resource and for each time interval:

3.1. Energy Dispatch Limits

3.1.1. Resource *energy* award has to be within the economic limits (*Energy offer/bid* limits).

$$\underline{\boldsymbol{En}}_{\boldsymbol{res}}^{\boldsymbol{t}} \leq \boldsymbol{En}_{\boldsymbol{res}}^{\boldsymbol{t}} \leq \overline{\boldsymbol{En}}_{\boldsymbol{res}}^{\boldsymbol{t}} \quad , \quad \boldsymbol{res} \in \boldsymbol{G}, \boldsymbol{L}$$ Resource *offer/bid* limits

3.2. Regulating Reserve Limits

3.2.1. Regulation Reserve awards (allotments) are less than the upper *offer* limit and are less than the *reserve* ramping capability (the regulation reserve ramping time multiplied by the regulation *ramp rate*).

$$Reg_{unit}^{Raise;t} \leq min\{\overline{Reg}_{unit}^{Raise;t} \; ; \; RR_{unit}^{RegUp} \cdot T_{dom}^{Reg}\}$$
$$Reg_{unit}^{Lower;t} \leq min\{\overline{Reg}_{unit}^{Lower;t} \; ; \; RR_{unit}^{RegDn} \cdot T_{dom}^{Reg}\}$$

3.3. Contingency Reserve Limits

3.3.1. Contingency Reserve awards (allotments) are less than the upper *offer* limit and are less than the contingency reserve ramping capability (contingency reserve ramping time multiplied by the *reserve ramp rate*).

$$Res_{unit}^{t} \leq min\{\overline{Res}_{unit}^{t} \; ; \; RR_{unit}^{Res} \cdot T_{dom}^{Res}\}$$

3.3.2. The *reserve ramp rate* is submitted as part of the *offer*, while *reserve* ramping time is the time required by service definition to reach full response.

3.4. Tie-Break Processing

3.4.1. For scenario of tie-breaking among *offers* for the same service or among *bids* for the same service, the soft 'tie breaking' constraint will be introduced that is enforcing pro-rata equality of awarded block MW quantities. Constraint enforces that the difference between awards for two equally priced blocks, pro-rated by their maximum value, should be equal to zero. As this is equality constraint, two single segment slack variables will be introduced per constraint. For a group of *N* identified blocks that are tied at the same price (from N *offers*, where N is expected to be 2 for most practical cases), and have to be subject to tie break processing, a set of N-1 equation will be written as:

$$\frac{BQ_{k,1}^{i}}{\overline{BQ}_{k,1}^{i}} - \frac{BQ_{k,2}^{j}}{\overline{BQ}_{k,2}^{j}} + \overline{Slack}_{TB,k}^{1} - \underline{Slack}_{TB,k}^{1} = 0$$

3.4.2. Where $BQ_{k,1}^{i}$, $BQ_{k,2}^{j}$ are ith and jth block quantities from first and second *offer* within the group, and $\overline{BQ}_{k,1}^{i}$, $\overline{BQ}_{k,2}^{j}$ are respective block sizes.

$$\frac{BQ_{k,2}^{m}}{\overline{BQ}_{k,2}^{m}} - \frac{BQ_{k,3}^{l}}{\overline{BQ}_{k,3}^{l}} + \overline{Slack}_{TB,k}^{2} - \underline{Slack}_{TB,k}^{2} = 0$$

$$\ldots$$

$$\frac{BQ_{k,n-1}^{u}}{\overline{BQ}_{k,n-1}^{u}} - \frac{BQ_{k,n}^{v}}{\overline{BQ}_{k,n}^{v}} + \overline{Slack}_{TB,k}^{n-1} - \underline{Slack}_{TB,k}^{n-1} = 0$$

3.4.3. The slack variables introduced will contribute to the Objective under very low penalty prices (comparing to other penalties), so the constraint can be violated by any other constraint. Analogous equations are written for equally priced *bid* block quantities. These *constraints* can be applied for *energy bid*/*offer* tie-breaking as well as for *reserve bid* tie breaking.

3.4.4. In addition, the tie breaking process will be applied to self-scheduled *generation* (e.g. Tie Breaking of self- scheduled generators in cases of *network* limitation).

3.4.5. To reflect the actual economics of the *market dispatch optimization model*, the "economic" tie breaking will be applied in the model only to resources with the same loss sensitivities (loss penalty factors). Since tie-breaking equations are part of the integral problem formulation, and not post processing, tie breaking solution reflects all the economic characteristics of the model, i.e. congestion costs or AS opportunity costs.

3.4.6. Tie breaking is also applied for *self-scheduled energy* resources in case of curtailment of projected schedule. For this scenario, *constraint violation coefficient* values will be defined for violation of *self-scheduled energy* dispatch in scheduling run. Then in pricing run setup, prices and *self-scheduled energy dispatch schedule* constraint will be set analogously to other soft *constraints*. Pro rata remains the same as for economic *offers*.

3.4.7. There is exception to economic tie breaking rules in curtailment of *self-scheduled energy* dispatch resources, where tie breaking in certain scenarios is performed so that curtailment is performed proportionally to submitted (or forecasted) self-schedules. For additional details please see Appendix A.3.

3.4.8. In case of tie between a *demand bid* and a generator *offer* (with same loss sensitivities), there is no pro-rating, instead the *load* served is maximized by addition of small "incentive term" making the combined *load*-*generation* award net positive to the objective.

SECTION 4 GENERATING/LOAD RESOURCE CONSTRAINTS

4.1. Energy Capacity Limits

4.1.1. When there is no *reserve offer* from the unit, e*nergy dispatch* has to be within unit operating limits:

$$EnL_{unit}^{t} \leq En_{unit}^{t} \leq EnH_{unit}^{t}$$

4.2. Constant Ramping Limits

4.2.1. The ramping capabilities of *generation* and *load* units are expressed as constant values of maximal Up and Down *Ramp Rates* over the full range of the resource power output. The Up and Down *Ramp Rate* Limits are calculated as a product of maximal Up and Down *Ramp rate* values and the *energy* ramping time domain:

$$RRL_{unit}^{Up} = RR_{unit}^{Up} \cdot T_{dom}^{En}; \quad RRL_{unit}^{Dn} = RR_{unit}^{Dn} \cdot T_{dom}^{En}; \quad unit \in G$$
$$RRL_{load}^{Up} = RR_{load}^{Up} \cdot T_{dom}^{En}; \quad RRL_{load}^{Dn} = RR_{load}^{Dn} \cdot T_{dom}^{En}; \quad load \in L.$$

4.2.2. For each *generation* and *load* unit and each time interval the following *energy* Up and Down *Ramp rate* Limits are posted:

$$-RRL_{unit}^{Dn} \leq En_{unit}^{t} - En_{unit}^{t-1} \leq RRL_{unit}^{Up}; \quad unit \in G; t \in T$$
$$-RRL_{load}^{Dn} \leq En_{load}^{t} - En_{load}^{t-1} \leq RRL_{load}^{Up}; \quad load \in L; t \in T.$$

4.2.3. The *energy* ramping time domain is dependent on the length of time interval.

4.3. Reserve Model

4.3.1. Core parts of the *Reserve* model are:

a. *Reserve* capacity limits
b. *Reserve* ramping
c. Combined *Energy* and *reserve* capacity limits
d. Combined *Energy* and *reserve* ramping
e. Independent model for Raise and Lower service in each *reserve* category

Resource Reserve capacity limits

4.3.2. In addition to limits imposed by *reserve offer* limits, there are physical unit limits that affect *reserve* award. One example is for fast and slow *reserves* limitation by Governor response. While Governor response also depends on frequency deviation, it is usually one curve provided for Market purpose, where response is given as function of *energy* output only. Typical Governor response curve is provided below:

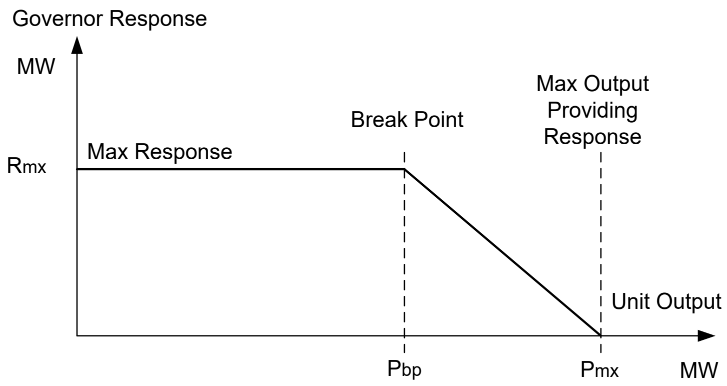

Figure 2: Governor *n* second raise droop characteristic

4.3.3. Each two-piece characteristic comprises:

a. maximum response amount which applies between zero *energy dispatch* and the contracted *energy dispatch* breakpoint and;
b. above the *energy dispatch* breakpoint there is linear decrease in response amount from the contracted maximum response amount down to zero maximum response at the maximum *energy* capacity.

4.3.4. The mathematical formulation using the variable designation from Figure 2 are as follows:

$$Res_{unit}^{t} = R_{mx} * (P_{mx} - P^{t})/(P_{mx} - P_{bp}) \; \forall \; P \geq P_{bp}$$
$$Res_{\mathrm{unit}}^{\mathrm{t}} = \mathrm{P_{mx}} \; \forall \; \mathrm{P} < P_{\mathrm{bp}}$$

4.3.5. In addition to maximum quantity, contracted generators might be subject to mandatory governor response, which is modeled as *reserve* self-schedule and protected with penalty in Scheduling Run (i.e. treated as price taker). Such self-schedule also contributes to regional *reserve requirements*.

Resource AS ramping limits

4.3.6. The individual *reserve* ramping constraint can be posted for each resource and each time interval. These *constraints* are expressed in time domain as follows (equation is provided for Regulation Raise, but analogous equation applies for each *reserve*:

$$\frac{Reg_{unit}^{Raise;t}}{RR_{unit}^{RegUp}} \leq T^{AS}; \quad unit \in G; t \in T$$

meaning that the *Reserve* ramping cannot exceed the specified *reserve* ramping (default 5 minutes).

Resource Combined Energy and Reserve Capacity Limits

4.3.7. Multiple market services can be provided by the same resource at the same time, but the total resource capacity is limited. For example, the capacity range of online *generation* resources can be used for *energy*, regulation raise capacity and contingency *reserve*.

4.3.8. The capacity range binding *energy* and *reserve* depends on the services involved. For example, for combined *Energy* and Regulating reserves, the regulating range is binding.

$$En_{unit}^{t} + RegRaise_{unit}^{t} \leq RH_{unit}^{t}$$
$$En_{unit}^{t} - RegLower_{unit}^{t} \geq RL_{unit}^{t}$$

4.3.9. In a scenario when regulating limits are not separately registered for a resource, the operating limits are used instead of regulating in the above equations.

4.3.10. For combined *Energy* and Contingency (Frequency Response) Service, the sum of the scheduled *energy* and the scheduled FCAS response ($PSRaise_{unit}^{t}$) must be less than or equal to the Governor Droop Raise Capacity $(GDRH_{unit}^{t})$ of that unit for each of the services:

$$En_{unit}^{t} + PSRaise_{unit}^{t} \leq GDRH_{unit}^{t}$$

4.3.11. Analogous capacity limits are posted on *load* entities. For example of Contingency reserve:

$$En_{load}^{t} - SRes_{load}^{t} \geq EL_{load}^{t}$$

Resource *Combined Energy and Reserve Ramping*[37]

4.3.12. If the *reserve* awards were dispatched for *contingency,* they would be converted into *energy* that needs to ramp, thus taking away ramping capability of dispatched *energy* award. The *energy* ramping period is the same as *dispatch interval*, so if it was fully utilized for *energy* ramping, there would be no room for additional *energy* ramping needed if *reserve* was activated. Therefore the *reserve* awards have to be taken into account in *energy* ramping model. *Energy* ramping capacity based on *energy ramp rate* is adjusted to address the impact from *reserve* awards. The upward and downward ramping equations can be expressed as:

$$P_i(t) - P_i(t-1) \leq RLU_i^{En}(t) - ASUp_i(t)$$
$$P_i(t-1) - P_i(t) \leq RLD_i^{En}(t) - ASDn_i(t)$$

where: ASUp and ASDn is upward/downward *reserve* impact to *energy* ramping capacity.

4.4. Other Operational Modes of Generators, Loads or Similar Facilities

4.4.1. Hybrid resources or other operational modes of generators, loads, or similar facilities include hydro pump storage and non-generating resources (NGR)[38] like batteries, flywheel, compressed air facilities, and other forms of primary energy storage.

4.4.2. Potential models for the treatment of these resources may incorporate variability of both supply offers and demand bids for more optimal economic results.

[37] Example is provided in Appendix A.3

[38] NGR is a device that has a continuous operating range from a negative to a positive power injection; i.e., it can operate continuously as either consumes load or provides power, and it can seamlessly switch between generating and consuming electrical energy. NGR functions like a generation resource and can provide energy and AS services.

SECTION 5 MARKET CLEARING PRICES

5.1. The SCDD model calculates constraint shadow costs as a byproduct of the optimization process. Those shadow costs are directly taken from optimization solution constraint dual variables and reflect change in the objective function due to incremental *constraint* relaxation.

5.2. These shadow costs indicate the effect on the objective function of the various *constraints*. The shadow costs related to the system power balance represent the marginal *energy* costs and refer to a location where the market requirement for *energy* is posted, i.e. to the central market place. These shadow costs present an equivalent to System marginal cost in classic unit commitment formulation.

5.3. The Marginal *Energy* Cost for each interval t is determined as shadow cost (λ_{En}^{t}) for *energy* balance *constraints* and it is the uniform price component for all market participants and pricing locations.

5.4. The Marginal Clearing Price is calculated as the As-*Bid* cost of the Marginal Resource.

SECTION 6 NODAL ENERGY DISPATCH PRICES (LOCATIONAL MARGINAL PRICES)

6.1. *Load* and generating unit contributions to the system power balance differ with respect to *network energy* losses and eventual transmission congestion. The *energy* prices are differentiated according to specific conditions of actual power injections and withdrawals at market participant locations. In general, *energy* prices are different at each *network* node, i.e. they present *nodal energy dispatch prices* or Locational Marginal Prices (LMP). In a widely accepted formulation, the *energy* LMP present the marginal cost of serving the incremental *load* at the price location by all available resources of the system.

6.2. The LMP is used to settle the market and is calculated in each run by SCDD. The LMP is calculated for each generator and participating *load*.

6.3. To support the settlement, the *energy* LMP is calculated at all pricing locations. Each pricing location corresponds to a single market *network* node where the generator or *load* resources are connected. Pricing locations can also include buses with no resources.

6.4. The Locational Marginal Prices for *energy* are calculated respecting *network* losses and eventual transmission congestion:

$$LMP_{En;node}^{t} = \lambda_{En}^{t}/pf_{node}^{t} + \sum_{line \in N} SF_{line;node} \cdot TSC_{line}^{t} \;\; ; \; t \in T; node \in G \cup L$$

6.5. Locational Marginal Prices are the same for *generation* and *load* entities at the same *network* node. The Locational Marginal Prices for *energy* consist of several components:

$LMP_{En;node}^{t} = \lambda_{En}^{t}$	- Marginal *Energy* Cost
$+\lambda_{En}^{t} \cdot (1 - pf_{node}^{t})/pf_{node}^{t}$	- Price for marginal *network energy* losses
$+ \sum_{line \in N} SF_{line;node} \cdot TSC_{line}^{t}$	- Price for marginal *network congestion*.

SECTION 7 RESERVE PRICING

7.1. Similar to *energy* pricing, the marginal cost approach is used for ancillary services pricing. The regional *reserve requirements* are posted as minimum and maximum regional limits. The shadow costs ($\lambda_{ASReg}^{AS;t}$) for posted regional *reserve requirements* present the corresponding shadow costs that are calculated as a by-product of the optimization process. These shadow costs present ancillary service Regional Clearing Prices for each ancillary service. These Regional Clearing Prices are used for *reserve* pricing purposes.

7.2. The regional *reserve shadow price* can be expressed the sum of “Reserve Clearing Price” $(ASMP_{ASReg}^{AS;t})$ and the “Opportunity Cost” $\left(LOC_{ASReg}^{AS;t}\right)$ as:

$$\lambda_{ASReg}^{AS;t} = ASMP_{ASReg}^{AS;t} + LOC_{AS\,Re\,g}^{AS;t}$$

7.3. The “Reserve Clearing Price” is calculated as part of SCDD solution post-processing, as the *reserve offer* price associated with the marginal block that was cleared in the market. Once obtained, then the “Opportunity Cost” is calculated as the difference between the regional *reserve requirement* constraint *shadow price* and the “Reserve Clearing Price”.

Resource Reserve Prices

7.4. The Resource Reserve Marginal Prices are calculated as summation of individual regional prices.

7.5. In general, each generating unit and *load* entity can have a different Reserve Marginal Price.

APPENDIX A.1 - MATHEMATICAL NOTATION

- Offer Costs

$C_{unit}^{En;t}(\cdot)$	is unit *energy generation* cost at time interval *t*
$C_{unit}^{RegRaise;t}(\cdot)$	is unit Regulation Raise cost at time interval *t*
$C_{unit}^{RegLower;t}(\cdot)$	is unit Regulation Lower cost at time interval *t*
$C_{unit}^{FFCS;t}(\cdot)$	is unit Fast Frequency Control Services cost at time interval *t*
$C_{load}^{curt}(\cdot)$	is *load* curtailment cost
$C_{load}^{En;t}(\cdot)$	is *load energy* cost at time interval *t*
$C_{constr}^{vio}(\cdot)$	is *constraint* violation cost at time interval *t*

- Energy Requirements

En_{req}^{t}	is market *energy* requirement at time interval *t*. This term refers to total unscheduled (forecasted) *load*
ΔEn_{req}^{t}	is change in market *energy* requirement at time interval *t*

- Reserve Requirements

$\underline{Reg}_{ASreq}^{Raise;t}$	is Regulation Raise minimum requirement for reserve region at time interval t
$\overline{Reg}_{ASreq}^{Lower;t}$	is Regulation Lower maximum requirement for *reserve region* at time interval *t*
$\underline{Reg}_{ASreq}^{Lower;t}$	is Regulation Lower minimum requirement for *reserve region* at time interval *t*
$\underline{Res}_{ASreq}^{t}$	is Frequency Control minimum requirement for *reserve region* at time interval *t*

- Product Quantities

En_{unit}^{t}	is unit *energy generation* at time interval *t*
En_{load}^{t}	is *load energy* consumption at time interval *t*[39]
$Reg_{unit}^{Raise;t}$	is unit Regulation Raise capacity at time interval *t*
$Reg_{unit}^{Lower;t}$	is unit Regulation Lower capacity at time interval *t*
Res_{unit}^{t}	is unit Reserve at time interval *t*

[39] En_{load}^{t} is defined as the load energy consumption of variable demand (price- sensitive or curtailable)
As such, the left- hand side of the system power balance equation refers to the (sum of generation) less (sum of price-sensitive load). If the bid of the price-sensitive load clears the market then En_{load}^{t} will represent the MW consumption of the price-sensitive load and the MDOM will schedule generation to cover both the price-sensitive load and energy requirement. If its bid does not clear then it will be scheduled at 0 MW, essentially curtailing it relative to its projected consumption or MW bid, and the MDOM will only schedule generation to cover the energy requirement. To put in another perspective, En_{load}^{t} = $MW\_Projected_{Load} - MW\_Curtailed_{Load}$.

$FFCS_{unit}^{t}$ is unit Fast Frequency Control Services quantity at time interval *t*
CV_{constr}^{t} is *constraint* violation quantity at time interval *t*

- Offer/Bid Limits

$\overline{En}_{res}^{t}$ is unit/load maximal *energy generation* at time interval *t*
$\underline{En}_{res}^{t}$ is unit/load minimal *energy generation* at time interval *t*
$\overline{Reg}_{unit}^{Raise;t}$ is unit maximal Regulation Raise capacity at time interval *t*
$\overline{Reg}_{unit}^{Lower;t}$ is unit maximal Regulation Lower capacity at time interval *t*
$\overline{Res}_{unit}^{t}$ is unit maximal contingency *reserve* at time interval *t*

- Resource Capacities

EnH_{unit}^{t} is unit *energy generation* high limit at time interval *t*
EnL_{unit}^{t} is unit *energy generation* low limit at time interval *t*
$\overline{En}_{unit}^{T}$ is unit *energy generation* maximum over time horizon *T*
EnH_{load}^{t} is *load energy* consumption high limit at time interval *t*
EnL_{load}^{t} is *load energy* consumption low limit at time interval *t*
$RegH_{unit}^{t}$ is unit regulation high limit at time interval *t*
$RegL_{unit}^{t}$ is unit regulation low limit at time interval *t*
$RRL_{unit/load}^{Up}$ is ramp-limited maximum increase of additional energy schedule for reserve
$RRL_{unit/load}^{Dn}$ is ramp-limited maximum decrease of additional energy schedule for reserve

- Ramping Rates

RR_{unit}^{Up} is unit *energy* Up *ramp rate*
RR_{unit}^{Dn} is unit *energy* Down *ramp rate*
RR_{unit}^{RegUp} is unit Regulation Raise *ramp rate*
RR_{unit}^{RegDn} is unit Regulation Lower *ramp rate*
RR_{unit}^{Res} is unit Reserve *ramp rate*
RR_{load}^{Up} is *load energy* Up *ramp rate*
RR_{load}^{Dn} is *load energy* Down *ramp rate*

- Time Domains

T_{dom}^{En} is *energy* ramping time domain
T_{dom}^{Reg} is regulation ramping time domain
T_{dom}^{Res} is *reserve* ramping Up time
T_{dom}^{En} is *energy* ramping time domain
T^{AS} is Ancillary Service ramping time

- Network Loss Model

En_{loss}^{t}	are *network energy* losses at time interval *t*
$En_{loss}^{base;t}$	are base *network energy* losses at time interval *t*
ΔEn_{loss}^{t}	is change of *network energy* losses at time interval *t*
$En_{unit/load}^{base;t}$	is unit/*load* base operating point at time interval *t*
α_{node}^{t}	is loss sensitivity factor for *node* or loss sensitivity to the change of *generation* in the *node* at time interval *t*
$pf_{unit/load}^{t}$	is loss penalty factor for *unit/load* at time interval *t*

- Transmission System Model

P_{line}^{t}	is line actual power flow at time interval *t*
SF_{line}^{node}	is shift factor for transmission *line* and *network node*
$P_{line}^{base;t}$	is line base power flow at time interval *t*
P_{node}^{t}	is actual *generation*/consumption at time interval *t*
$P_{node}^{base,t}$	is *unit*/*load* base *generation*/consumption at time interval *t*
$\underline{P}_{line}^{t}$	is line minimal power flow limit at time interval *t*
$\overline{P}_{line}^{t}$	is line maximal power flow limit at time interval *t*
TSC_{line}^{t}	is the transmission shadow cost for *line* constraint at time interval *t*
$line \in N$	is the set of *transmission lines*
$node \in NN$	is the set of *network nodes*

- Commodity Prices

$LMP_{node}^{En;t}$	is Locational Marginal Price for *energy* at *network node* at time interval *t*
$LMP_{Pnode}^{En;t}$	is Locational Marginal Price for *energy* at Pricing Location at time interval *t*
CV_{constr}^{t}	is Constraint Violation for constraint *constr* at time interval *t*

- Market Constituents

$unit \in G$	is the set of online generating units
$load \in L$	is the set of dispatchable *loads*

- Market Timeline

$t \in T$	is scheduling time horizon *T* divided into time intervals *t*
Δ_t	is the duration of the time interval *t*
ρ_t	is the duration of the time interval *t* as a fraction of an hour.

APPENDIX A.2 - COMBINED ENERGY AND RESERVE RAMPING EXAMPLE

To put a numerical example for equations for Resource Combined *Energy* and Reserve Ramping under Section 4.3, let us say that a unit has maximum ramp up rate of 6 MW per minute; that would mean the unit can ramp its power output at maximum 30 MW up from its initial condition (5 minutes times 6 MW per minute equals 30 MW, that is the maximum amount for $RLU_i^{En}(t)$ value).

Let us say that initial condition P(t-1) is 50 MW. In case when there are no *reserve* awards, unit can reach 80 MW at the end of *dispatch interval.*

Now let us assume that the unit for the same interval is awarded 10 MW of Regulation Raise.

In case the unit is called to provide Regulation Raise service (*reserve* award is activated into *energy*), then the unit has to ramp up those ten MWs during the interval, and that ramping comes in addition to ramping of unit's *energy* award.

Model will ensure that *energy* schedule P(t) is no more than the 50 MW (initial condition) + 30 MW (*energy* ramping) – 10 MW (regulation award) for the end of the interval.

So in case where this unit is called for delivery of 10 MW of Regulation Raise award, unit would be able to reach new set point set by *AGC.*

In an example, if a unit is awarded by Market at 65 MW of *energy* for particular interval, and then 10 MW of Regulation Raise, then if the Regulation Raise is activated by the *System Operator*, it would be possible for unit to ramp from its initial condition to the new set point of 65 MW +10 MW = 75 MW, as ramping requirement for the interval of 75 MW – 50 MW (initial condition) = 25 MW, that the unit can ramp in less than five minutes (with max ramping capability of 30 MW over the length of *Dispatch Interval*).

APPENDIX A.3 - SELF-SCHEDULED ENERGY DISPATCH CURTAILMENT

In accordance with current *System Operator* operational practice, in a scenario where a group of *self-scheduled energy generating units* is self-scheduled at multiple points of a multi-leg radial connection, and the curtailment has to be performed for the group, there is specific rule for curtailing the individual units. In such a case, the units are curtailed proportionally to their self-scheduled MW, regardless of economics. To illustrate that practice, example for *self-scheduled energy* is provided below.

In the example shown in Figure 3 below, units D and E have the lowest priority and will be cut first. In this example the Shift Factors for Generators D and E, with respect to the flow on line 2 are assumed to be 1, so the total curtailed MW amount (5 MW) is equal to the MW flow relief (5 MW) of the line 2. This curtailment of 5 MW is distributed among units D and E proportionally to their self-scheduled MWs,, i.e. unit D is getting 40% of the total curtailment, while unit E is getting 60% of the relief.

It is important to note the assumptions for this processing:

- Processing only applies to units that are self-scheduled.
- Units subject to this processing are having the same priority.
- Units are not subject to ramping *constraints* (being self-scheduled, no ramping *constraints* are applicable per convention).
- Economic impact is to be disregarded (i.e. economical impact of incremental losses or shift factors).
- Minimum operating limit (Pmin) of the units subject to this processing is considered to be zero unless registration data is non-zero. If the *minimum stable load* (Pmin) is greater than zero, then the pro-rata adjustments only applies to Nominated quantities above the Pmin. For example, if the Nomination is 100 MW and the unit Registered Pmin is 40 MW, the amount subject to pro-rata curtailment is 60 MW and that is the coefficient used in the curtailment pro-rata processing (not the Nominated 100 MW).

The examples shown in this Appendix are for illustration only and does not include all categories of generating units. The actual implementation shall be in accordance with the values as set out in the WESM Constraints Violation Coefficients and Pricing Re-runs (CVC-PR) Manual and related provisions of the WESM Rules and other relevant Market Manuals.

Generator	Gen Type	Priority #	Segment 1		Segment 2		Segment 3		Segment 4	
			P1	Q1	P2	Q2	P3	Q3	P4	Q4
GEN_A	Scheduled	–	NA	10	-100	20	150	35		
GEN_B	Self-Scheduled	1	NA	15						
GEN_C	Scheduled	–	NA	150	0	265				
GEN_D	Self-Scheduled	2	NA	20						
GEN_E	Self-Scheduled	2	NA	30						

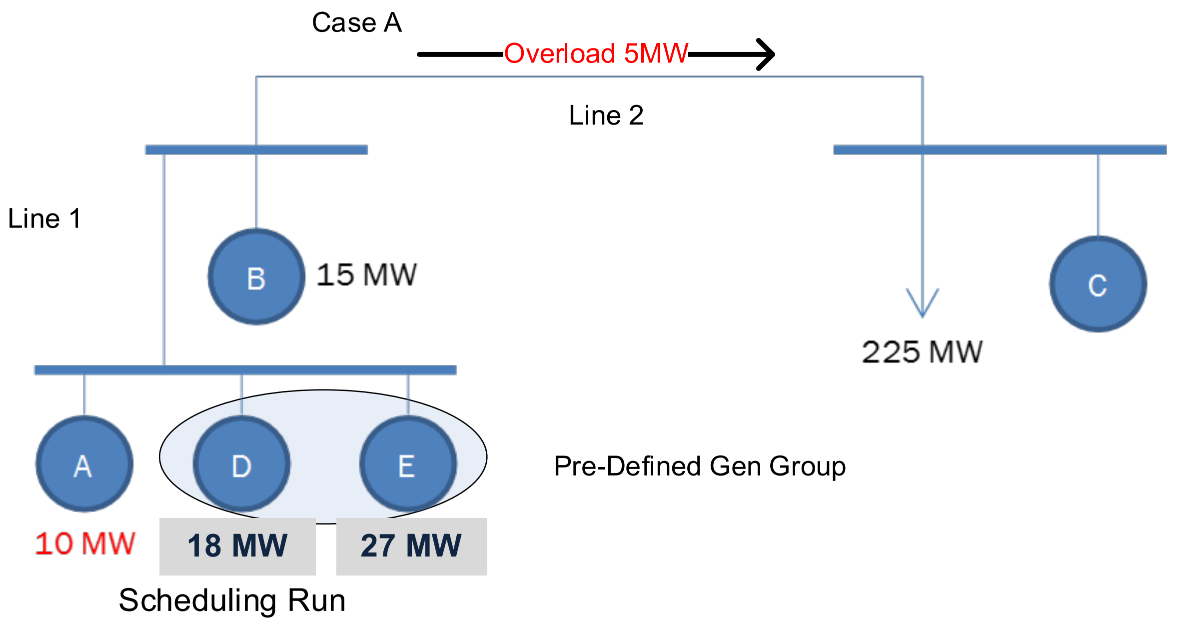

Figure 3: Example of pro-rata curtailment of electrically identical units

In order to provide such functionality, and disregard the economics of the case, the following constraint can be added to the model:

- (En(E,t)-Pmin(E,t)/(Pnom(E,t)- Pmin(E,t)) = (En(D,t)- Pmin(D,t))/(Pnom(D,t)- Pmin(D,t));

Where *En(D,t),Pmin(D,t), Pnom(D,t)* are awarded MW, Pmin and Nominated (self scheduled) MW respectively, for unit *D* in time interval *t*.

While the constraint seems trivial, it will be written only for units that are satisfying the above assumptions, plus the additional assumptions as follows:

- Units have to be defined to belong to a special “pro-rata group”; each unit within the group is subject to prorata processing that links units within the group with the equations above.
- “Pro rata” Groups are defined ahead of time. There can be many groups, and many units within each group, but one unit can belong to only one “pro-rata group”.

Such approach would also satisfy scenario as listed in Figure 4 below:

Generator	Gen Type	Priority #	Segment 1		Segment 2		Segment 3		Segment 4	
			P1	Q1	P2	Q2	P3	Q3	P4	Q4
GEN_A	Scheduled	—	NA	10	-100	20	150	35		
GEN_B	Self-Scheduled	2	NA	15						
GEN_C	Scheduled	—	NA	150	0	265				
GEN_D	Self-Scheduled	1	NA	20						
GEN_E	Self-Scheduled	2	NA	30						

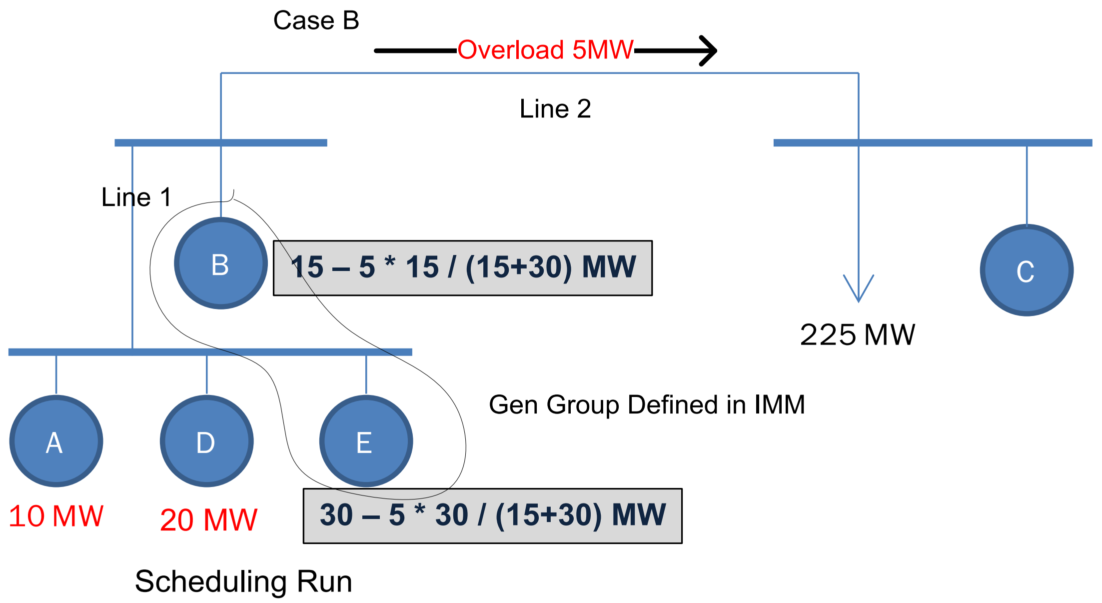

Figure 4: Example of pro-rata curtailment of electrically different units

However, the approach described so far might not be suitable for scenario as listed in Figure 5. For this scenario the pro-rate processing should not be applied (i.e. if the shift factors of the units within the group do not have the same sign).

Generator	Gen Type	Priority #	Segment 1		Segment 2		Segment 3		Segment 4	
			P1	Q1	P2	Q2	P3	Q3	P4	Q4
GEN_A	Scheduled	—	NA	10	-100	20	150	35		
GEN_B	Self-Scheduled	2	NA	15						
GEN_C	Scheduled	—	NA	150	0	265				
GEN_D	Self-Scheduled	1	NA	20						
GEN_E	Self-Scheduled	2	NA	30						

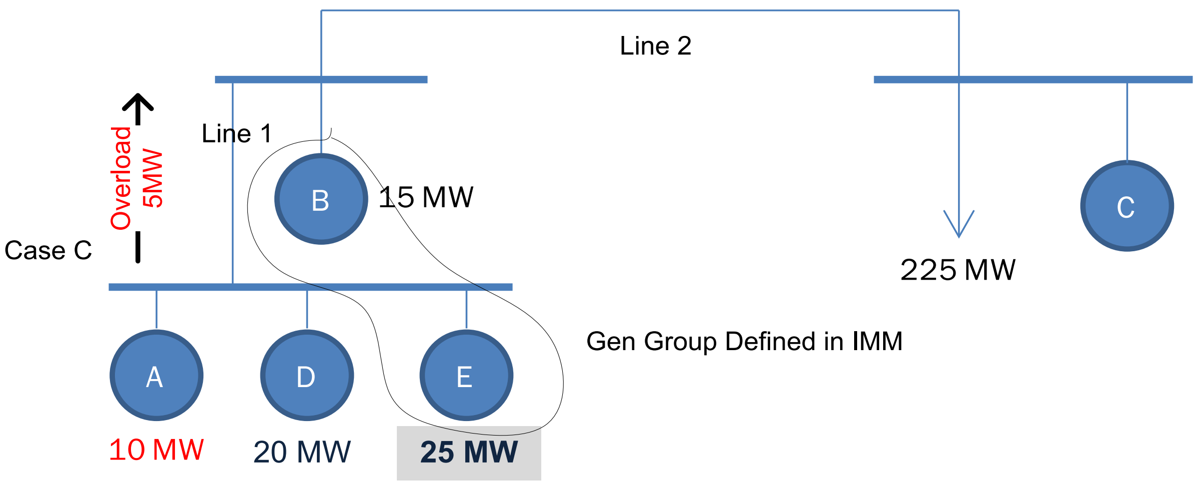

Figure 5: Example of pro-rata curtailment of electrically different units with shift factors of different sign

The approach would also not be suitable for scenario that would involve congestion both on lines 1 and 2 at the same time.

Under such scenarios, where the shift factors of the units within the group are of different sign with respect to a *network constraint,* only the units with same sign shift factors (those providing counter-flow to the congestion) will be subject to pro-rata curtailment.

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.

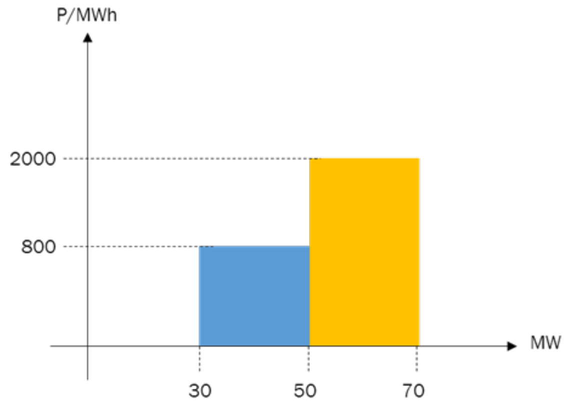

Figure 6. Generator A Price Curve

The price curve of Gen B is shown below.

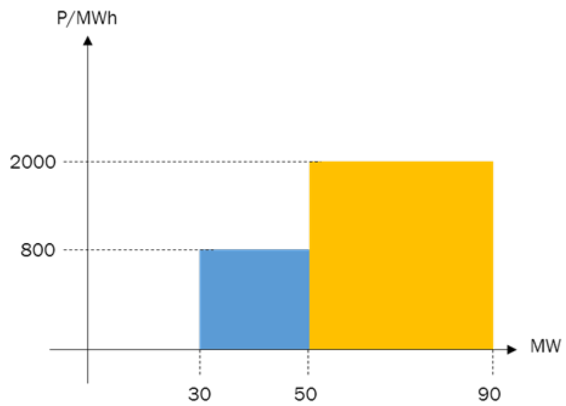

Figure 7. Generator B Price Curve

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

$$\text{Additional Schedule for Gen A} = 40 * \left[\frac{20}{40+20}\right] = 13.33 \text{ MW}$$

$$\text{Additional Schedule for Gen B} = 40 * \left[\frac{40}{40+20}\right] = 26.67 \text{ MW}$$

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 – Provisions Prior to Interconnection of Mindanao

SECTION 1 SCOPE

1.1 For this Appendix, the Luzon-Visayas settlement region shall refer to the combined Luzon and Visayas *grids* while the Mindanao settlement region shall refer to the Mindanao *grid.*

1.2 This Appendix specifies the relevant calculations under the administered price determination methodology under Section 7 that will be performed per settlement region prior to the interconnection of the Mindanao *grid* to the Luzon and Visayas *grids*[40].

1.3 This appendix specifies the relevant calculations used to determine and allocate the *net settlement surplus* under Section 9 that will be performed per settlement region prior to the interconnection of the Mindanao *grid* to the Luzon and Visayas *grids*[41].

1.4 Other calculations provided in Section 7 and Section 9 that do not appear in this appendix will be as provided in those Sections even prior to the interconnection of the Mindanao *grid* to the Luzon and Visayas *grids.*

SECTION 2 GENERATOR ENERGY ADMINISTERED PRICE

2.1 During the first four (4) weeks from the effective date of implementation of WESM in Mindanao and when there are valid prices in the region, the average effective monthly rate per fuel or technology type will be used for the calculation of *Generator Energy Administered Price* in Section 7.2. Thereafter, and when sufficient historical data is available, the application of the methodology herein shall cease, and the methodology indicated in Section 7 shall apply.

2.2 *Generator Trading Participants* must submit their monthly effective rate, based on their Power Supply Agreement contracts, as approved by the ERC approved, to the *Market Operator*. If the *Market Operator* does not receive the effective monthly rate for a particular fuel type, then the *Market Operator* shall set the *Generator Energy Administered Price* of the particular fuel type to be zero (0).

2.3 The *Generator Energy Administered Price* per fuel type shall be determined as follows:

$$EAP_f = \frac{\sum_{k=1}^{Nf} Rate_{k,f}}{N_f}$$

Where:

EAP_f	refers to the *energy administered price* for fuel type *f*
$Rate_{k,f}$	refers to the monthly effective rate for *generator resource k* with fuel type *f*
N_f	refers to the number of generator resource in the region applied with *market intervention* or *market suspension* with fuel type *f*

[40] WESM Rules Clause 10.5.4
[41] WESM Rules Claus 10.5.2.

SECTION 3 CUSTOMER ENERGY ADMINISTERED PRICE

3.1. In reference to Section 7.3.1, the *energy administered price* for all *customer* resources for a *dispatch interval* shall be calculated considering the positive *snapshot quantities* of all *generator* resources and *snapshot quantities* of all *customer* resources from the same settlement region (Luzon/Visayas or Mindanao).

SECTION 4 CALCULATION OF NET SETTLEMENT SURPLUS

4.1 In reference to Section 9.2.1 and 9.2.2, the *net settlement surplus or net settlement deficit* amount shall be calculated per *dispatch interval* and settlement region (Luzon/Visayas or Mindanao) using the total amounts to be collected and paid from the same settlement region.

4.2 In reference to Section 9.4.2, the amount to be returned to a *Trading Participant* for a *settlement interval* shall be equal to the ratio of the *Trading Participant's* line loss or congestion charge payment to the total line loss or congestion charge payment of all *Trading Participants* in the same settlement region where the subject *Trading Participant* is located, multiplied by the total *net settlement surplus* or net settlement deficit amount due to loss or congestion for the same settlement region.

4.3 In reference to Section 9.4.2 (h) and 9.5.3, the generation-weighted average marginal loss cost and generation-weighted average marginal congestion cost for a *dispatch interval* shall consider the marginal loss cost and marginal congestion cost of resources within the same settlement region.

4.4 In reference to Section 9.4.3 and 9.5.3, when the *nodal energy dispatch prices* of all resources in a settlement region 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 or net settlement deficit* for that settlement region for that *dispatch interval* shall be allocated to *customer* resources within the same settlement region on a pro-rata basis depending on each *customer* resource's share in the total *energy settlement quantity,* as determined under WESM Rules clause 3.13.6, of all customer resources from that settlement region.

Appendix D – Slack Variables for Under-generation and Over-generation (Illustrative Example)

Under-generation Example

With reference to Appendix A section 2.1.3, the following power system balance equation is shown.

$$\sum_{unit \in G} En_{unit}^{t} - \sum_{load \in L} En_{load}^{t} + Q_{UG} = En_{req}^{t} + En_{loss}^{t} + Q_{OG} \;;\; t \in T$$

Where:

are slack variables for under and over *generation*.

Q_{UG} and Q_{OG}	are slack variables for under and over generation
En_{unit}^{t}	is unit energy generation at time t
En_{load}^{t}	is energy consumption of price-sensitive load at time interval t
En_{req}^{t}	is market energy requirement at time interval t. This term refers to total unscheduled (forecasted) load
En_{loss}^{t}	are network energy losses at time interval t

Let us assume that the variables represented above have the following values.

Variable	Description	Assumed Value
En_{unit}^{t}	Total generation available that can be scheduled	10,000 MW
En_{load}^{t}	Price sensitive load	0 MW (no demand bid)
En_{req}^{t}	Total load requirement	10,050 MW
En_{loss}^{t}	Total MW losses	250 MW

Replacing the variables in the equation with the assumed values, we get the following.

$$10{,}000 - 0 + Q_{UG} = 10{,}050 + 250 + Q_{OG}$$

First, it should be noted that slack variables are non-negative values, such as in the case of Q_{UG} and Q_{OG}.

With this said, Q_{UG} should be equal to 300 MW, while Q_{OG} shall be zero to maintain the equality constraint in this equation. Having a 300 MW value for Q_{UG} means that there is an under-generation of 300 MW.

It should also be noted that having no slack variables would result to the *MDOM* having no solution at all since it shall be unable to resolve this equality constraint.

Over-generation Example

Using the same formula for the power system balance equation in Appendix A section 2.1.3, let us assume that its variables have the following values.

Variable	Description	Assumed Value
En_{unit}^{t}	Total generation scheduled at minimum limit (e.g. limited based on ramping)	4,500 MW
En_{load}^{t}	Price sensitive load	0 MW (no demand bid)
En_{req}^{t}	Total load requirement	4,000 MW
En_{loss}^{t}	Total MW losses	80 MW

Replacing the variables in the equation with the assumed values, we get the following.

$$4{,}500 - 0 + Q_{UG} = 4{,}000 + 80 + Q_{OG}$$

As previously mentioned, slack variables are non-negative values, such as in the case of Q_{UG} and Q_{OG}.

With this said, Q_{OG} should be equal to 420 MW, while Q_{UG} shall be zero to maintain the equality constraint in this equation. Having a 420 MW value for Q_{OG} means that there is an over-generation of 420 MW.

Appendix E – Interim Generator Energy Administered Price

A. Initial Period for Luzon and Visayas[42]

During the first four (4) weeks from the effective date of implementation of this *Market Manual* and when there are valid prices, the historical locational marginal prices will be used for the calculation of *Generator Energy Administered Price* in Section 7.2. Thereafter, and when sufficient historical data is available, the application of the methodology herein shall cease, and the methodology indicated in Section 7 shall apply.

The *Generator Energy Administered Price* for the initial period, that is, the interim Generator Energy Administered Price, shall be determined using the historical ex-post price of the similar trading day as equivalent to the historical five-minute final nodal energy dispatch price (FEDP). To generate historical five-minute FEDPs, the succeeding hour ex-post price of the similar day shall be replicated for the affected five-minute intervals.

To illustrate, if *market intervention* was declared for 8:05:00-9:30:00 on 26 June 2021, Saturday, then the ex-post price of trading interval 9:00 shall be utilized as the FEDP of *dispatch intervals* 8:05:00 until 9:00:00 while the ex-post price of trading interval 10:00 shall be utilized as the FEDP of *dispatch intervals* 9:05:00 until 9:30:00. This process shall be replicated to arrive at the affected intervals of the four (4) most recent similar trading days, such that the historical FEDPs to be used in Section 7.2.4 are the historical ex-post prices from the following trading intervals and trading days:

Affected Dispatch Intervals	Four (4) most recent similar trading days of 26 June 2021, Saturday			
	1 29 May 2021	2 05 June 2021	3 12 June 2021	4 19 June 2021
8:05:00 – 9:00:00	Ex-post prices of trading interval 9:00			
9:05:00 – 9:30:00	Ex-post prices of trading interval 10:00			

B. Initial Period with Visayas-Mindanao Interconnection[43]

During the first four (4) weeks from the effective date of implementation of this *Market Manual* and when there are valid prices with the Visayas-Mindanao interconnection already completed and fully functional, the *Generator Energy Administered Price* in Mindanao shall be computed in accordance with the formula below. Thereafter, and when sufficient historical data is available, the application of the methodology herein shall cease, and the methodology indicated in Section 7 shall apply.

$$EAP_{k,D,i} = \frac{\sum_{k' \in K_i, k' \neq k} \left(EAP_{k',D,i} * SQ_{k',D,i} \right)}{\sum_{k' \in K_i, k' \neq k} SQ_{k',D,i}}$$

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*

[42] Pages 187-190 & 261 of ERC Decision on ERC Case 2017-042 RC dated 29 December 2020
[43] ibid

$SQ_{k',D,i}$	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*