FORECAST

PHILIPPINE ELECTRICITY MARKET CORPORATION JOURNAL



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VOLUME 1 ISSUE NO. 1

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Forecast, the PEMC Journal is a semi-annual publication of the Philippine Electricity Market Corporation (PEMC) envisioned to be a compilation of policy papers, studies and discussion pieces relating to the governance and operation of the Wholesale Electricity Spot Market (WESM) with contributions originating from the PEMC employees.

This is the first and only electricity journal in the Philippines that aims to examine topics relating to the country's electricity bourse.

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1

FINANCIAL IMPACT OF THE INTEGRATION OF FIT QUALIFIED RESOURCES *in the* WESM

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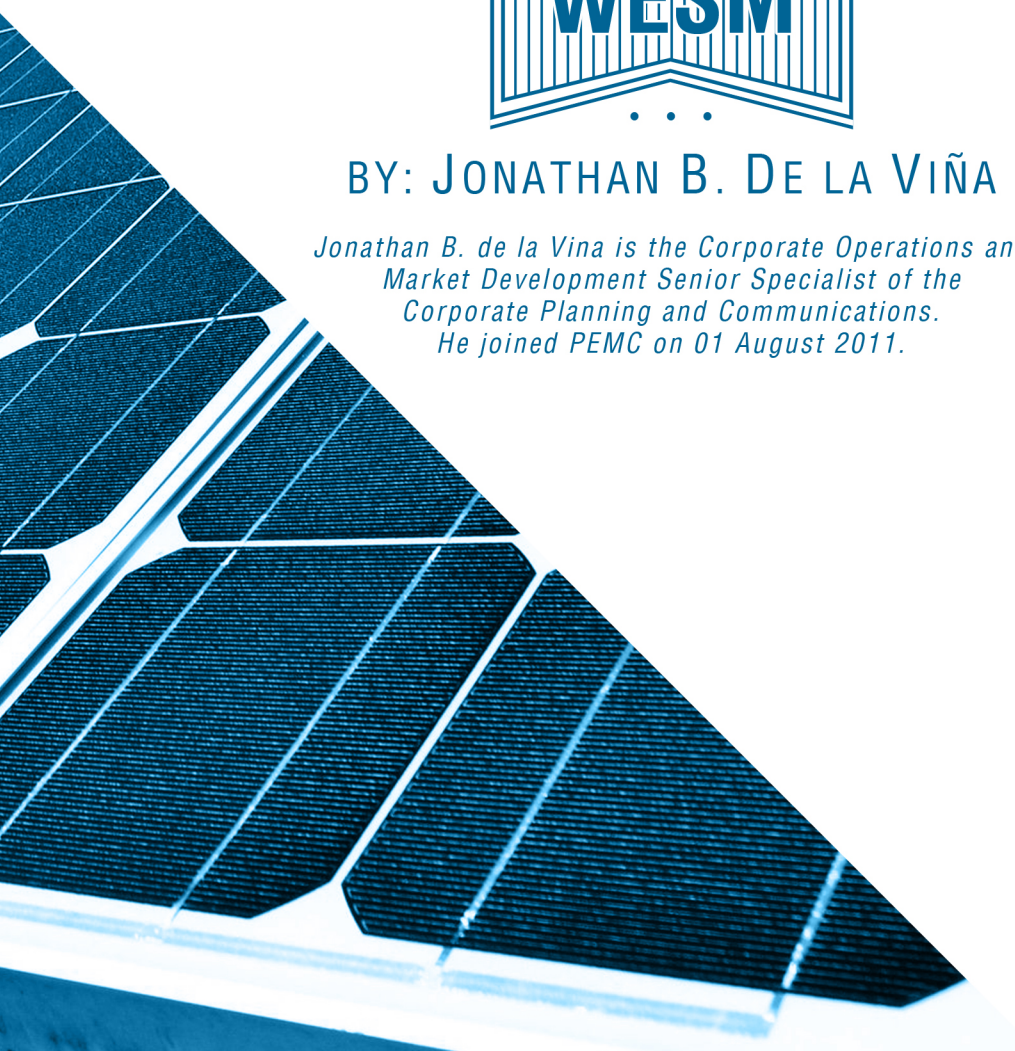

ABSTRACT

The accelerated development and integration of intermittent renewable energy RE resources to the Philippine grid is expected to have a financial impact to the grid end-users considering the incentives provided under the law and the intermittent nature of the said resources. This study estimates the financial impact to the end-users based on the estimated changes in energy and reserve costs of those end-users. The impact on energy costs are estimated by simulating the spot prices with and without the intermittent resources; on the other hand, the impact on reserve costs are estimated by analyzing the historical variability of the system and the intermittent resources. Given the cost, expected installed capacity, and intermittency of wind and solar power plants, this study focuses on the financial impact of the integration of those technologies in the grid. Furthermore, this study translates the financial impact to specific groups of end-users, namely, a large private distribution utility in Luzon, rest of Luzon and Visayas, and Mindanao.The results of the study indicate that the integration of the assumed wind capacity is a net benefit to the system. If the assumed solar capacity is added, however, the financial impact becomes an additional cost to the system. When the results are translated to each of the end-user groups, it was observed that the impact on the end-users depend on their exposure to the spot market, that is, although the integration of intermittent resources may be a net benefit to the system, the financial impact to an end-user may still be an additional cost depending on its spot exposure and vice versa.

Key Terms – feed-in tariff, intermittent renewable energy resources, must dispatch, priority dispatch, renewable energy, reserve, solar, wind

INTRODUCTION

BACKGROUND

Section 7 of the Renewable Energy Act (RA 9513) provided for the implementation of a feed-in tariff (FIT) system for electricity produced from wind, solar, ocean, run-of-river hydropower and biomass. Under the feed-in tariff system, eligible generating units are guaranteed payment for its generation at a fixed rate, called the "FIT Rate", for twenty (20) years. By instituting a guaranteed rate, the economic feasibility of projects for the development of the targeted technologies is assured to potential investors. As approved by the Energy Regulatory Commission (ERC)[1], the FIT rates for the different technologies are as follows:

Technology	FIT Rate (PHP / kWh)
Run-of-River Hydro	5.90
Wind	8.53
Solar	9.68
Biomass	6.64

Table 1 ERC-approved FIT Rates for different technologies.

In addition to a guaranteed rate, FIT-eligible generating units are also provided priority purchase and transmission on their production. Since dispatch scheduling is centralized in the grids where the Wholesale Electricity Spot Market (WESM) is implemented (i.e., Luzon and Visayas), the dispatch of FIT-eligible generating units should be considered in the scheduling and pricing processes of the WESM.

OBJECTIVE OF THE STUDY

From the previous section, it was discussed that FIT-eligible generating plants are provided two (2) primary incentives: a guaranteed FIT rate and priority scheduling and dispatch. Contextualizing these incentives under the current pricing and scheduling processes of the grid, these incentives may be observed to be departure from the current market-based pricing and scheduling regime. Given this, it is expected that the integration of FIT-eligible generating plants would have financial implications to end-users.

This study aims to estimate the financial impact of these incentives to the end-users.

1 ERC Resolution No. 10, Series of 2012

METHODOLOGY

This section describes the methodology employed in the estimation of the financial impact of the integration of intermittent renewable energy resources to end-users.

APPROACH

This study will estimate the financial impact of the integration of renewable energy resources to end-users through the application of a scenario-based approach. Under this approach, costs under scenarios with and without intermittent renewable energy resource in the grid will be simulated and compared. The difference between the overall costs of each scenario with intermittent RE resources to the scenario without intermittent RE resources in the grid would correspond to the estimate of the financial impact of each scenario to the end-users. Figure 1 provides an illustration of the approach used for this study.

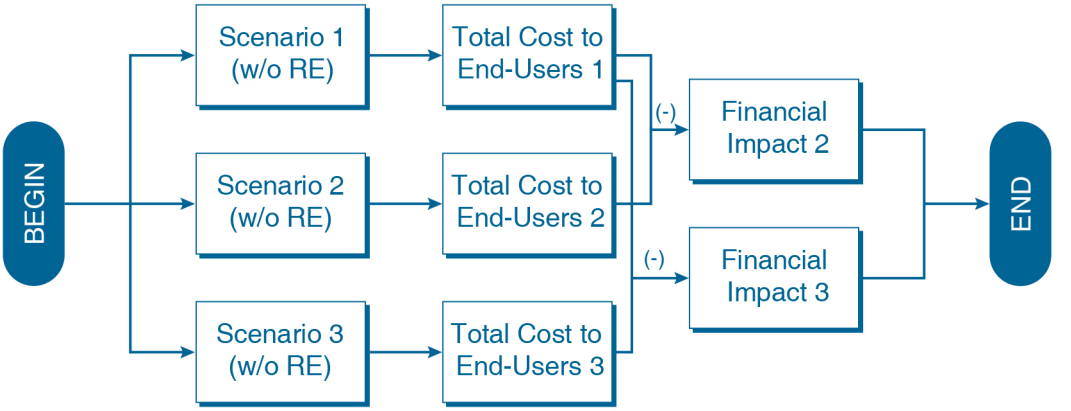

Figure 1 Illustration of the Study Approach

SIMULATION PERIOD

In order to consider seasonal variations, the financial impact of the integration of intermittent RE resources will be assessed on a one-year basis. That is, the overall financial impact will be calculated as the total impact for one (1) year. For this study, the year considered is the period starting 26 December 2013 and ending 25 December 2014.

SCENARIOS

For the estimation of the financial impact of the integration of intermittent RE resources, this study will be making use of scenarios. The scenarios are differentiated by the intermittent RE capacity assumptions used in the determination of the different costs. Excluding the base scenario where there are no intermittent RE resources in the grid, the following scenarios are considered:

No.	Wind Capacity (MW)	Solar Capacity (MW)	Total Intermittent RE Capacity (MW)
1	337	0	337
2	337	500	837

Table 2 Capacity assumptions of each scenario excluding the base scenario.

The wind capacity assumption of 337 MW is based on the total capacity registered in the WESM as of 2014. The breakdown of the 337 MW is as follows:

Plant Name	Capacity
Burgos	150
Caparispisan	81
North Wind Phases I & II	33
North Wind Phase III	19
San Lorenzo	54
TOTAL	**337**

On the other hand, the solar capacity assumption of 500 MW-DC is based on the new FIT installation target set by the Department of Energy (DOE) for solar[2]. The 500 MW-DC capacity is assumed to be located within the Luzon and Visayas grids.

The financial impact of the integration of the other FIT-eligible technologies (i.e., run of river hydro, biomass) is not expected to be as significant as the impact of the integration of wind and solar plants considering the expected capacities and level of their corresponding FIT rates. In order to simplify the simulations and the presentation of results, special considerations for those technologies in the simulations will not be performed.

ENERGY COST IMPACT CALCULATION

As one of the incentives under the FIT system, FIT-eligible generating plants are provided priority scheduling and dispatch. With this incentive, FIT-eligible generating plants do not have to compete with other generators in the WESM but only has to nominate their forecasted generation, which would result to their immediate scheduling as price-takers. This is expected to affect the energy costs of end-users in two (2) ways: the benefit from the Merit Order Effect and the payment of the FIT Differential. Figure 2 provides the flow chart of the methodology for the calculation of the impact to the energy costs of end-users. This is discussed in detail in a latter sub-section.

2 "In the matter of the adoption of amendments to Resolution No. 10, Series of 2012, a resolution approving the feed-in tariff (FIT) rates, as necessitated by the new installation target for solar energy generation set by the Department of Energy". www.erc.gov.ph:8099/Notice/NoticeDownload/977

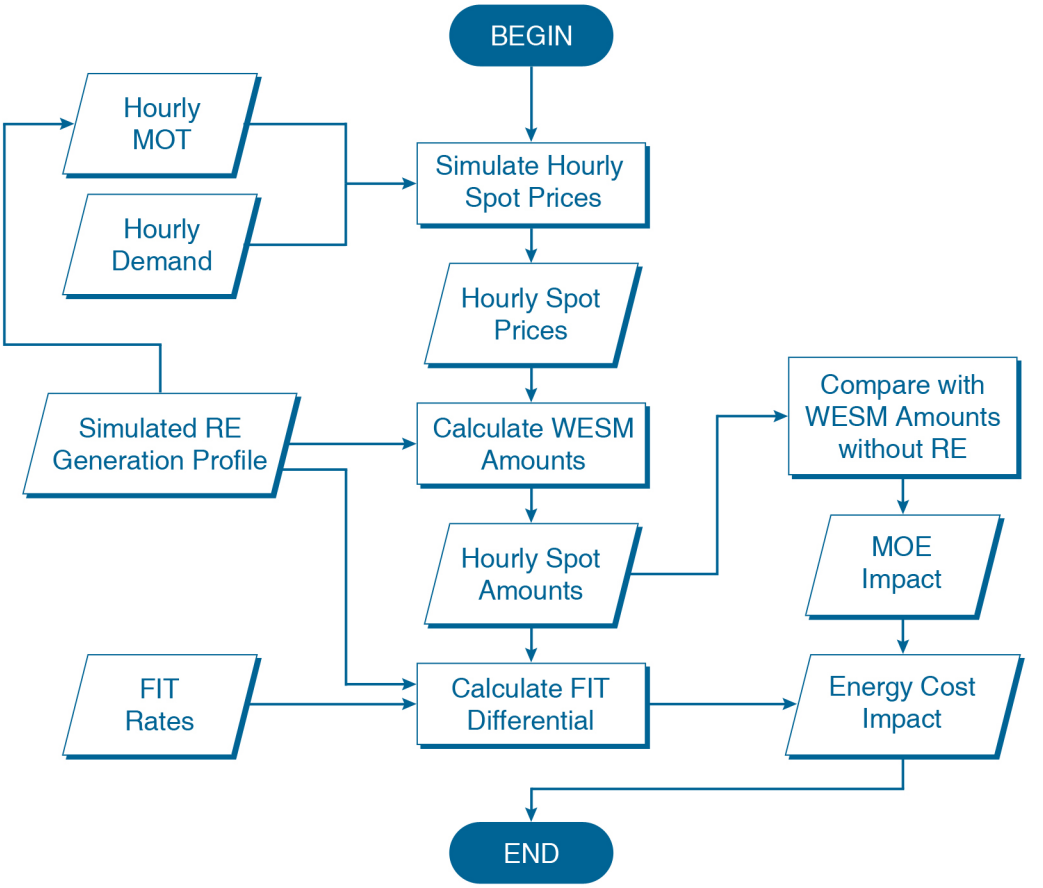

Figure 2 Flow Chart of the Methodology of the Energy Cost Impact Calculation

Merit Order Effect

Since FIT-eligible generating plants are considered price-takers in the WESM, they reduce the demand which are to be competed for by market-based generating plants. Assuming there are no changes in the behavior of trading participants, this could result to lower prices in the WESM. This phenomenon is called the "merit order effect" and has been observed in other jurisdictions such as Germany[3]. Figure 3 provides an illustration of this effect.

3 Sensfuß, F., Ragwitz, M., & Genoese, M. (2007). The Merit-order effect: A detailed analysis of the price effect of renewable electricity generation on spot market prices in Germany

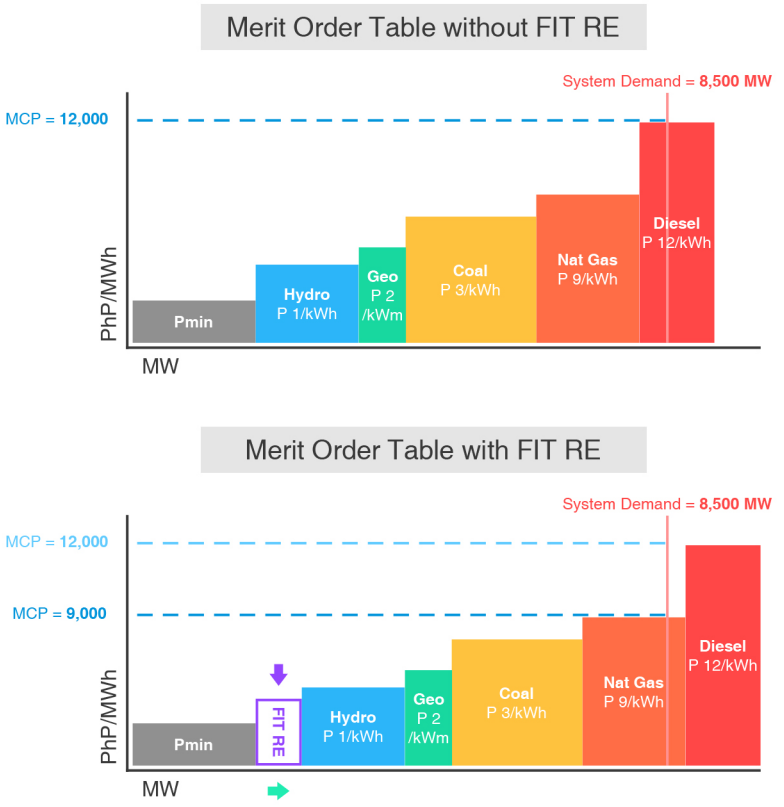

Figure 3 Illustration of the Merit Order Effect

In the above illustration, the demand was assumed at 8,500 MW. In the top illustration, the resulting market clearing price (MCP) in the WESM is PHP 12,000 / MWh, which was set by a diesel plant. With the priority dispatch of FIT-eligible generating plants ("FIT RE"), the MCP in the WESM decreased to PHP 9,000 / MWh as shown in the bottom figure. Since the WESM employs uniform pricing in settlement, the decrease in the MCP affects the total spot quantity and not just specific generators.

In order to estimate the impact of the Merit Order Effect to end-users, the cost of energy purchased from the WESM with and without the FIT-eligible generating plants will be compared. If the cost of energy from the WESM is lower with the FIT-eligible generating plants then the difference in amount would be considered as the benefit of the integration of the intermittent RE resources to the grid and vice versa. The Merit Order Effect (MOE) Impact will be calculated as follows:

$$MOE\ Impact = Spot\ Cost_{w/\ FIT\ RE} - Spot\ Cost_{w/o\ FIT\ RE}$$

Eq. 1

In this study, all financial implications will be presented from the perspective of end-users. That is, negative amounts presented will be considered as costs, while positive amounts are benefits to the end-users. As such, if the calculated MOE Impact is a positive amount then the impact is a benefit to the end-users. On the other hand, if the calculated amount has a negative value then the impact is an additional cost to the end-users.

To simplify the calculation of the spot cost, a single-part settlement will be implemented in this study in lieu of the two-part settlement implemented in the WESM. The hourly spot cost will be calculated using the following equation:

$$Spot\ Cost = Spot\ Price \times Spot\ Quantity$$

Eq. 2

The two (2) components required to calculate for the hourly spot cost will then be determined as follows:

a. Spot Price – refers to the simulated hourly market clearing price (in PHP/MWh) determined using actual ex-ante merit order tables and demand from 2014. Conditions with and without the implementation of the Secondary Cap will be simulated.
b. Spot Quantity – refers to the actual hourly settlement data (in MWh) from 2014.

FIT Differential

Based on the ERC FIT Rules[4], FIT-eligible generating plants should not be bound under any contract to supply energy to any customer. In effect, all generation by FIT-eligible generating plants are to be sold to the WESM. As such, FIT-eligible generating plants will have revenues from the WESM based on their actual production and applicable spot price. In order to be settled at their guaranteed FIT rate, FIT-eligible generating plants will have to be paid an additional amount equivalent to the difference of its guaranteed FIT revenue and its WESM revenues. This amount is called the "FIT Differential" and will be calculated on an hourly basis, as follows:

$$FIT\ Differential = Guaranteed\ FIT\ Revenue - WESM\ Revenue$$

Eq. 3

The FIT Differential will be on top of the WESM payment if the WESM rate is lower than the FIT rate. Otherwise, the WESM proceeds will cover the entire FIT payment, while the excess will be kept in the FIT-All Fund.

The hourly Guaranteed FIT Revenue will be calculated as follows:

$$Guaranteed\ FIT\ Revenue = FIT\ Rate \times Metered\ Quantity$$

Eq. 4

Where,
FIT Rate – guaranteed fixed rate (in PHP/MWh) for the technology as provided in Table 1
Metered Quantity – actual production (in MWh) of the generating plant

4 Section 1.4

The hourly WESM Revenue will be calculated as follows:

$$WESM\ Revenue = Spot\ Price \times Metered\ Quantity$$

Eq. 5

Where,
Spot Price – refers to the simulated hourly market clearing price (in PHP/MWh) determined using actual ex-ante merit order tables and demand from 2014. Conditions with and without the implementation of the Secondary Cap will be simulated.
Metered Quantity – actual production (in MWh) of the generating plant

Similar to the Merit Order Effect Impact, if the calculated FIT differential is a positive amount, then the impact of the integration of intermittent RE resources with regard to the FIT differential is a benefit to the end-users and vice versa. This could occur if the generating plants that the FIT-eligible generating plants displaced have higher rates than the FIT rates (e.g., diesel plants).

RESERVE COST IMPACT CALCULATION

One of the operational issues commonly associated with wind and solar plants is their intermittency. Since wind and solar power plants derive their electricity from intermittent sources, their production of electricity is also generally erratic. Although there are reserves in place to address fluctuations in the system (i.e., regulating reserve), the additional variability introduced by the integration of considerable intermittent generating capacities in the grid may require augmentation of these reserves.

In this study, two (2) factors are expected to affect the variability of the system with the integration of intermittent RE resources to the grid:

a. Forecasting error of the production of the intermittent RE resources, and
b. Intra-hour variability of the intermittent RE resources.

By taking the maximum total variability introduced by the two (2) factors and doubling it, the required amount of regulating reserve to address the overall variability introduced by intermittent generation may be determined. In mathematical terms,

$$Reqd.\ \ Regulating\ Reserve = 2 \times (Forecasting\ Error_{Max} + Intra\text{ - }Hour\ \ ariability_{Max})$$

Eq. 6

The total of the forecasting error and intra-hour variation is doubled to determine the additional regulating reserve since the previous two (2) figures are presented as one-directional (i.e., either upward or downward). Using a 15% forecasting error as an example, the regulating reserve should be able to cover an upward variation of 15% and a downward variation of 15%, hence, the regulating reserve required is twice the 15% of the forecasted intermittent RE generation.

In order to determine if additional regulating reserve is required, the current variability of the system demand should also be analyzed. Similar to the factors considered in the determination of the variability of intermittent RE resources, system demand was also analyzed for its forecasting error and intra-hour variability. Using the same formula for intermittent generation (Eq. 6), the minimum regulating reserve to address system demand fluctuations may also be determined. Any additional regulating reserve may then be determined by comparing the total variability from intermittent generation and system demand to the current regulating reserve determination as per the Ancillary Services Procurement Plan (ASPP)[5], which is 4% of the forecasted system demand. Figure 4 provides an illustration of the methodology for determining if additional regulating reserve would be required with the integration of intermittent RE resources in the grid.

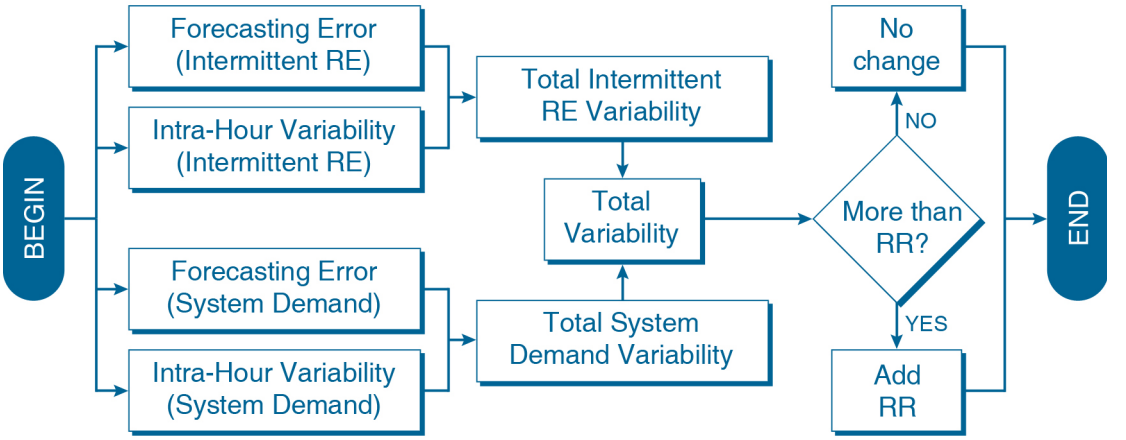

Figure 4 Illustration of the Determination of Additional Regulating Reserve

To exclude any outliers, this study will consider the 95th percentile (P95) of the forecasting error and intra-hour variability in the determination of the required regulating reserve. That is, (Eq. 6) will be adjusted as follows:

$$Reqd.\ Regulating\ Reserve = 2 \times (Forecasting\ Error_{p95} + Intra\text{-}Hour\ Variability_{p95})$$

Eq. 7

By using the 95th percentile, the additional required regulating reserve calculated will only be able to cover 95% of the variability of intermittent RE resources. Subsequently, variability of intermittent RE resources is expected to not be fully addressed by the regulating reserve 5% of the time.

If it is determined that the integration of the intermittent RE resource would require additional regulative reserve capacities, the additional cost will be estimated. Figure 5 provides the flow chart of the methodology for the calculation of the impact to the reserve costs of end-users. This will be discussed in detail in a latter sub-section.

5 Section 3.3.1

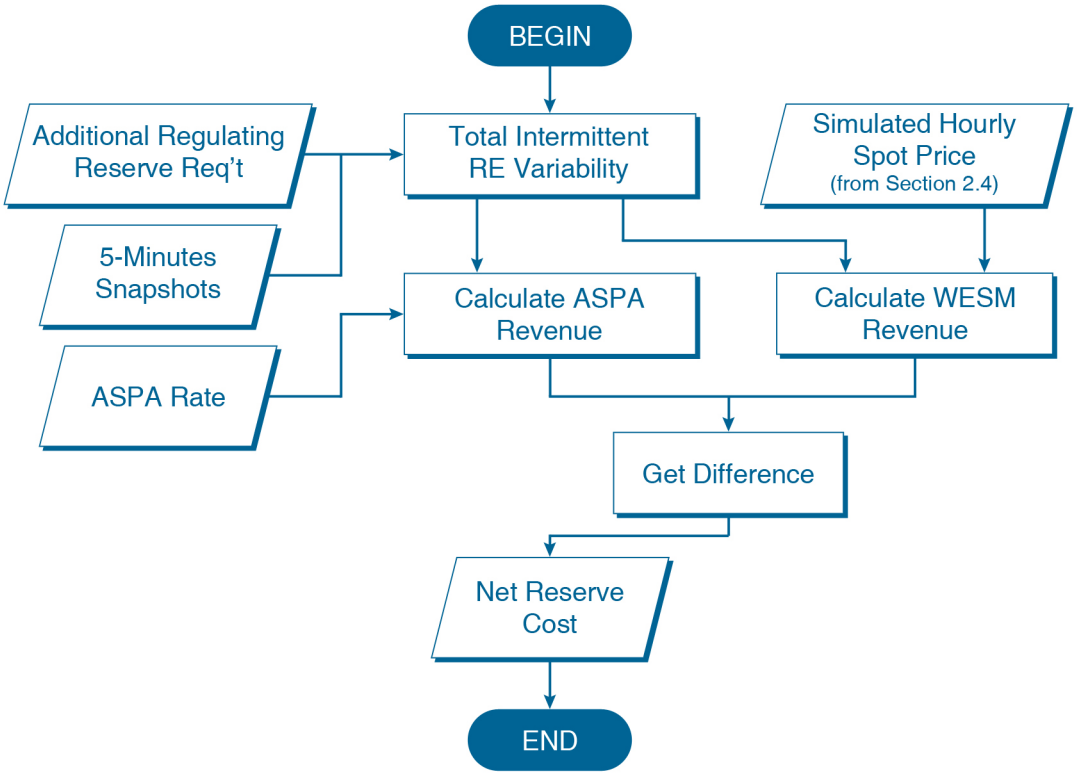

Figure 5 Flow Chart of the Methodology of the Reserve Cost Impact Calculation

Forecasting Error

Since FIT-eligible generating plants are provided priority dispatch and scheduling, all nominations, which are assumed to be based on their forecasts, provided by those plants are immediately included in the dispatch schedule published by the WESM. Considering that forecasts are rarely 100% accurate, system balancing due to forecasting errors is inevitable with the integration of intermittent RE resources to the grid. The system balancing is performed through the utilization of the regulating reserves. As mentioned in this section, the 95th percentile of the forecasting error will be determined for intermittent RE resources and the system demand. Generally, forecasting error is calculated as follows:

$$Forecasting\ Error\ (\%) = \frac{|Actual\ MW - Forecast\ MW|}{Actual\ MW} \times 100\%$$

Eq. 8

Based on (Eq. 8), actual and forecasted MW production of the intermittent RE resources are required to calculate their forecasting errors. Due to unavailability of forecast information by intermittent RE resources, however, their forecasting errors may not be readily calculated. In this regard, this study will be using the 95th percentile error standard provided in the Philippine Grid Code (PGC)[6] for total intermittent generation forecasting, which is set at 15%.

6 Draft Amendment No. 2, SDS 7.2.2.2

For the forecasting error of system demand, actual ex-ante and ex-post data from 2014 were used to derive the 95th percentile value. Using (Eq. 8), the resulting equation for the calculation of forecasting errors for system demand is as follows:

$$Forecasting\ Error\ (\%) = \frac{|MW_{RTX} - MW_{RTD}|}{MW_{RTX}} \times 100\%$$

Eq. 9

Where,
MW_{RTX} – total ex-post schedule (in MW) of all generating capacities
MW_{RTD} – total ex-ante schedule (in MW) of all generating capacities

Intra-Hour Variation

In the WESM, generating plants are to provide their dispatch on an hourly basis and are expected to ramp to their target schedule at the top of the hour on a linear basis. When generating plants deviate from this behavior ("Intra-Hour Variation"), the regulating reserve is used to balance the system. The same concept applies to the system demand. To estimate the amount of regulating reserve required to address intra-hour variation, a line will be fitted to the 5-minute snapshots of each interval and will be considered as the ideal curve of the intermittent RE resources without intra-hour deviation. The curve that will be used is the best-fit line for the 5-minute snapshots within each interval and corresponds to the line that would result to the minimum sum of squares of the distance of each snapshot to the line (Refer to Appendix A for the algorithm used in determining the best-fit lines). Figure 6 provides a sample of a best-fit line superimposed on the graph of 5-minute snapshots.

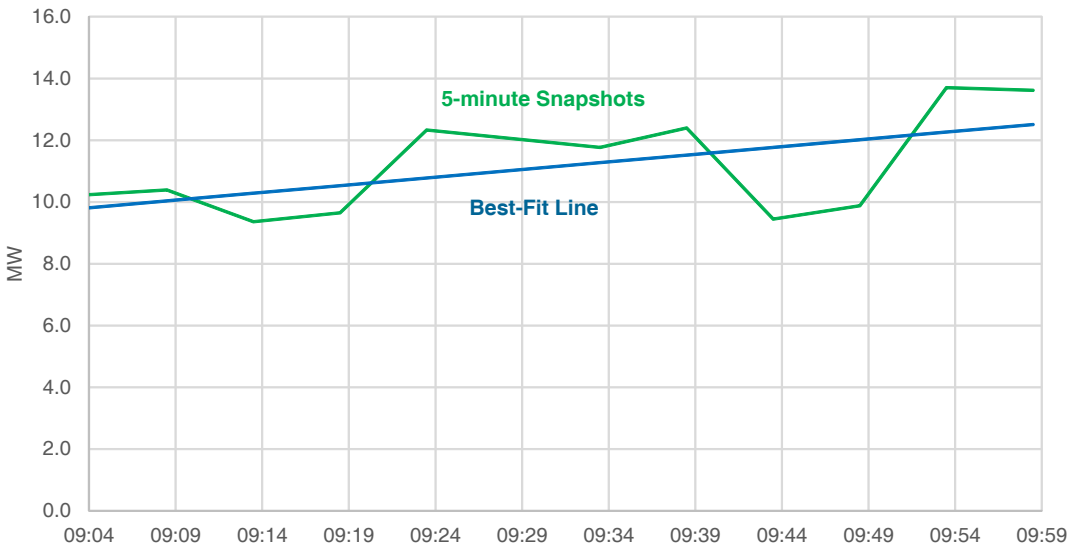

Figure 6 Sample Best-Fit Line on 5-Minutes Snapshots

After the best-fit lines are determined, intra-hour variations are calculated based on the vertical distance of each snapshot to their best-fit line. This process will be performed for intermittent RE resources and system demand. In this study, representative nodes were used in determining the intra-hour variability of wind power plants, solar power plants, and system demand. Table 3 provides the representative nodes for each item.

Item	Node
Wind	1NWIND_G01
Solar	6SACASL_G01
System Demand	2BALNT_T1L1

Table 3 Representative nodes for the analysis on intra-hour variability

The representative nodes for the wind and solar plants were selected because of the presence of those types of generating plants in those nodes. For the system demand, the representative node was selected based on its status as having the highest demand in 2014.

Cost Assumptions

In the event that additional regulating reserve capacity is found to be necessary to ensure system stability with the additional variability from intermittent RE resources, additional costs will also be incurred by the end-users. According to an Ancillary Services Procurement Agreement (ASPA) approved by the ERC[7], "the ASPA rate shall be recovered through settlement on the Wholesale Electricity Spot Market (WESM)" provided that the ancillary services provider "shall be entitled to a Monthly Minimum Incidental Energy Cost". Based on these provisions, this study assumes that ancillary services providers would be guaranteed a revenue equivalent to its ASPA rate applied to the capacity scheduled as regulating reserve. In mathematical terms,

$$ASPA\ Revenue = Capacity\ Scheduled \times ASPA\ Rate$$

Eq. 10

Where,
ASPA Revenue – guaranteed revenue (in PHP) of the ancillary service provider for having its capacity scheduled to provide regulating reserve
Capacity Scheduled – additional capacity scheduled (in MW) for regulating reserve to address variability of intermittent RE resources
ASPA Rate – fixed rate (in PHP/MW/h) paid to the generating plant for providing ancillary services. For this study, the assumed ASPA rate is set to PHP 3.00 / kW / h.

7 ERC Case No. 2013-054RC. "In the matter of the application for approval of the Ancillary Services Procurement Agreement between the National Grid Corporation of the Philippines (NGCP) and SN Aboitiz Power-Benguet Incorporate (SNAP-Benguet), with prayer for the issuance of provisional authority".

In addition to the guaranteed ASPA revenue of the ancillary services provider, the ERC-approved ASPA also provides for the recovery of costs through the WESM. This will be calculated as follows:

$$WESM\ Revenue = Dispatched\ Energy \times Spot\ Price \quad \text{Eq. 11}$$

Where,
WESM Revenue –revenue (in PHP) of the ancillary service provider from the WESM for dispatched energy in the provision of reserve
Dispatched Energy – energy (in MWh) produced by the ancillary services provider for the provision of regulating reserve to address variability of intermittent RE resources
Spot Price – simulated hourly market clearing price (in PHP/MWh) determined using actual ex-ante merit order tables and demand from 2014

Based on the formula, the hourly dispatched energy of the ancillary services provider is required. The following assumptions will be made in determining this quantity based on actual operations:

a. The ancillary services provider is constantly dispatched at half of its regulating reserve schedule; and
b. Additional energy is dispatched when the production of the intermittent RE resources varies downwards.

Figure 7 provides an illustration of the estimation of the hourly energy dispatched.

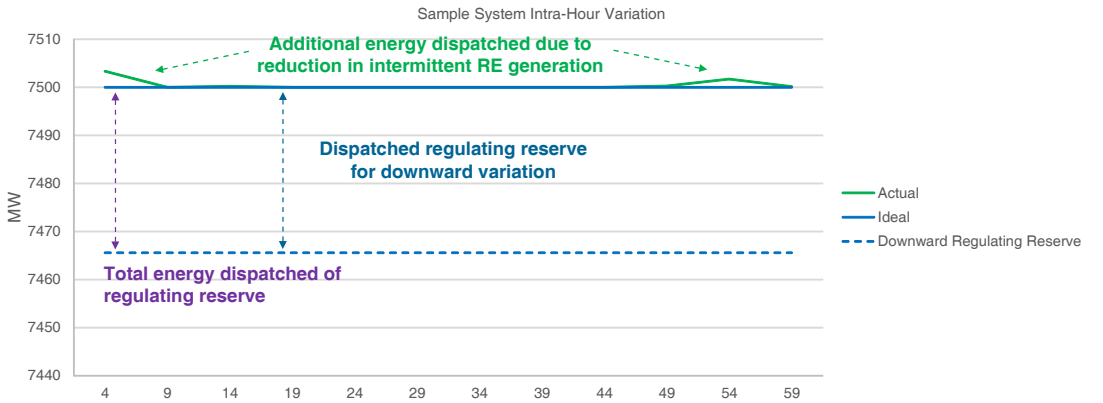

Figure 7 Illustration of the Estimation of Dispatched Energy

Since the WESM revenue may offset the guaranteed ASPA revenue of the ancillary services provider, the net reserve cost that would be paid for by the end-users is the difference of the two (2) revenues. That is,

$$Net\ Reserve\ Cost = ASPA\ Revenue - WESM\ Revenue \quad \text{Eq. 12}$$

The ASPA, however, only indicates that ancillary services providers are entitled to a minimum revenue. As such, if the WESM revenue of the ancillary services provider is greater than its ASPA revenue then the ancillary services provider is not required to remit any excess WESM

revenue. Assuming a negative value for both the ASPA revenue and WESM revenue since those amounts are costs from the perspective of the end-user, a negative value for the net reserve cost would correspond to an additional cost for end-users. In this study, the cost of regulating reserves would only be recovered from Luzon and Visayas end-users since it was assumed that the additional intermittent RE resources are located within the Luzon and Visayas grids.

RESOURCE PRODUCTION PROFILE

This section provides the methodology for the determination of the wind and solar generation profiles.

Wind Profile

The hourly wind generation profile utilized in this study was sourced from the Wind Energy Development Association of the Philippines (WEDAP). The same hourly wind generation profile was used by The Lantau Group in its paper entitled, "A brief assessment of additional wind capacity in the WESM," published last 15 October 2014. The data from WEDAP provides an hourly profile for each month (e.g., same generation for all interval 1 in January). This data would be scaled-up to the installed capacity of 337 MW for the simulations. Table 4 provides the general characteristics of the profile from WEDAP after scaling up.

Characteristic	Value
Installed Capacity	337 MW
Capacity Factor	27%
Peak Generation	195.2 MW

Table 4 General characteristics of the wind generation profile.

Moreover, Figure 8 provides the monthly profile of the data from WEDAP after scaling up.

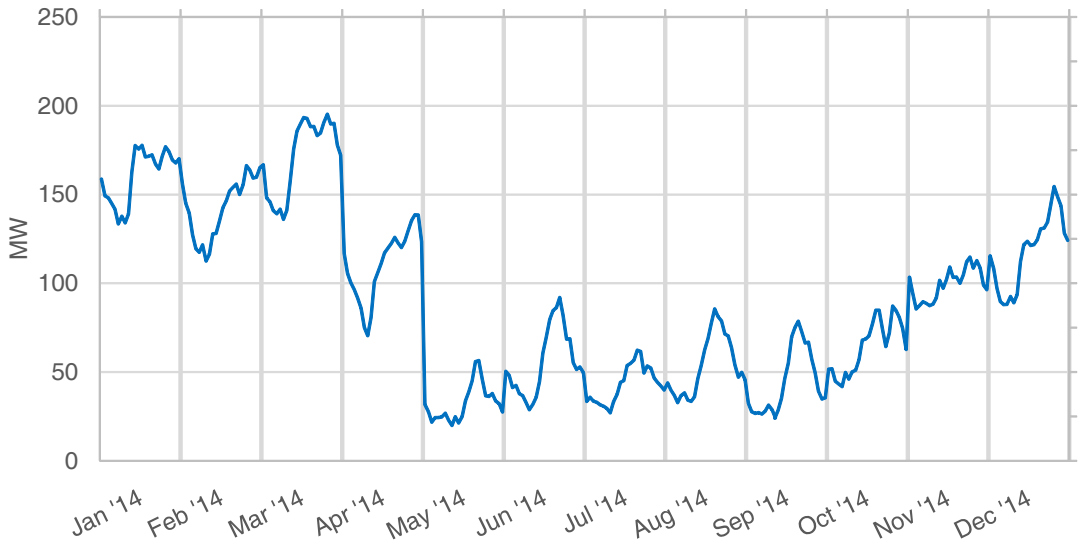

Figure 8 Monthly Profile of Wind Generation

Based on the monthly profile of the wind generation, the generation of wind power plants are relatively high during the months of January to April and November to December ("peak months"). The generation is then relatively low during the period starting May up to October ("off-peak months"). In terms of the hourly profile, Figure 9 provides the illustration of the daily load profiles for the peak months, while Figure 10 provides the illustration for the off-peak months.

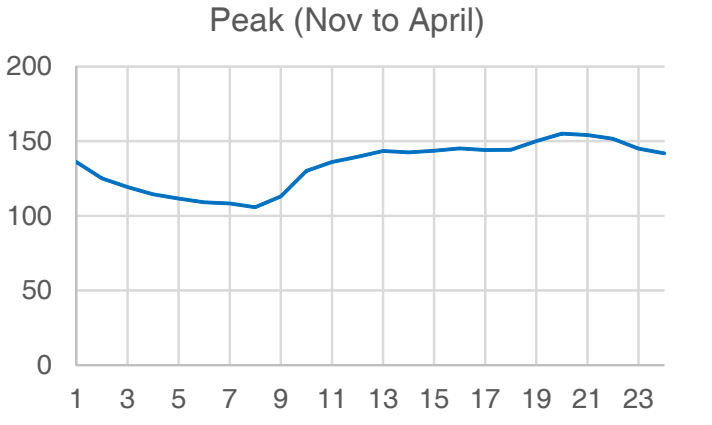

Figure 9 Hourly Profile of Wind Generation during Peak Months

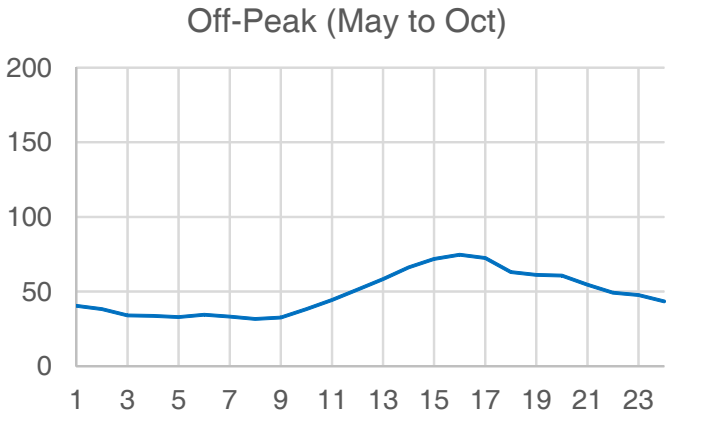

Figure 10 Hourly Profile of Wind Generation during Off-Peak Months

Solar Profile

For the solar profile, a profiling tool by the National Renewable Energy Laboratory (NREL) of the United States of America called "PVWatts© Calculator[8]" was used (refer to Appendix B for the configuration used). The data from the PVWatts© Calculator provides an hourly profile for each day (i.e., different generation for each hour from 01 January to 31 December). Table 5 provides the general characteristics of the profile from the PVWatts© Calculator for a 500 MW-DC solar power plant.

8 http://pvwatts.nrel.gov/

Characteristic	Value
Installed Capacity	500 MW-DC
Capacity Factor	16.4%
Peak Generation	395.7 MW

Table 5 General characteristics of the solar generation profile.

Figure 11 provides the monthly profile of the solar generation data.

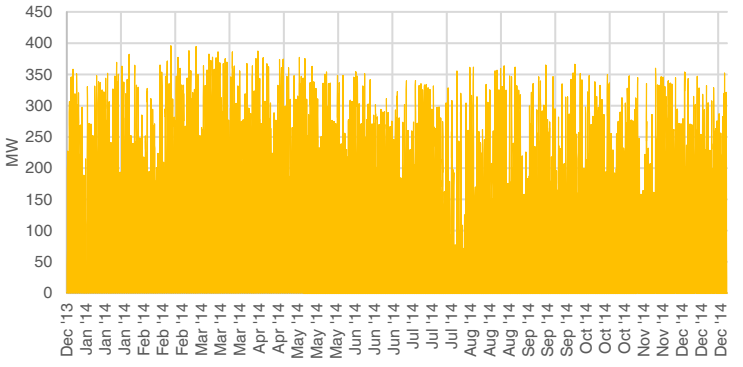

Figure 11 Monthly Profile of Solar Generation

Based on the monthly profile, no distinct peak or off-peak months can be identified similar to the wind generation profile. Figure 12 provides the hourly profile of the data from the PV-Watts© Calculator.

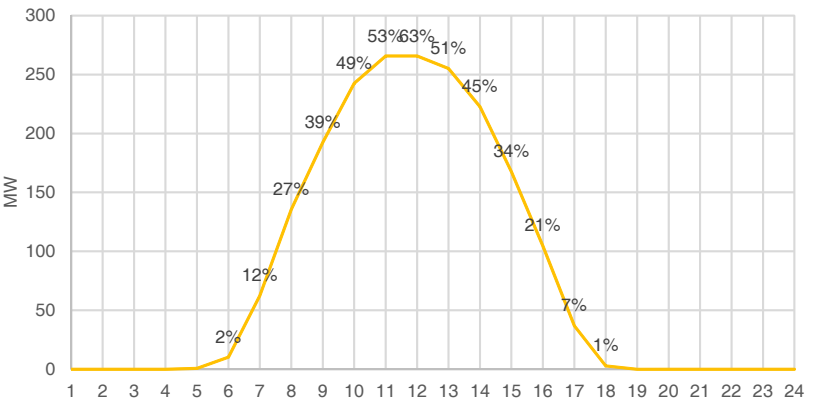

Figure 12 Hourly Profile of Solar Generation

END-USER FINANCIAL IMPACT CALCULATION

The output of the calculations discussed in Section 2.4 and Section 2.5 is the financial impact of the integration of intermittent RE resources to the grid when considered as a whole. This section discusses the methodology for estimating the financial impact of the integration of intermittent RE resources to specific end-users. For this study, the end-users are divided into three (3) groups: a large private distribution utility in Luzon, Rest of Luzon and Visayas, and Mindanao.

Energy Cost Impact

In Section 2.4, it was discussed that the integration of intermittent RE resources to the grid would impact the energy costs of end-users through two (2) ways: Merit Order Effect and FIT Differential.

To estimate the impact of the merit order effect to each group of end-users, the total Merit Order Effect will be pro-rated to each group of end-user based on their spot quantity. This is because, the Merit Order Effect only affects the pricing in the spot market and an end-user will only realize an impact corresponding to its quantity purchased from the WESM.
The following equation will be used:

$$MOE\ Impact_{EndUser} = MOE\ Impact_{System} \times \frac{SQ_{EndUser}}{SQ_{System}}$$

Eq. 13

Where,
MOE Impact – impact (in PHP) of the Merit Order Effect on the end-user or system
SQ – quantity (in MWh) purchased from the spot market or "Spot Quantity"

On the other hand, according to the ERC FIT Rules[9], additional costs related to the implementation of the FIT system will be recovered from the end-users based on their gross consumption. In this regard, the impact of the FIT Differential to each end-user will be estimated by pro-rating the total FIT Differential to each group of end-user based on their metered quantity. In mathematical terms,

$$FIT\ Differential_{EndUser} = FIT\ Differential_{System} \times \frac{MQ_{EndUser}}{MQ_{System}}$$

Eq. 14

Where,
FIT Differential – amount (in PHP) corresponding to the difference in the guaranteed FIT revenue and WESM revenue of FIT-eligible generating plants that would be charged to the system or end-user
MQ – actual consumption (in MWh) of the system or end-user, or "Metered Quantity"

The total of the two (2) components would correspond to the energy cost impact to each group of end-user. The rate impact may be determined by dividing the energy cost impact of each end-user group by their respective metered quantities.

Reserve Cost Impact

Since reserve costs are currently being charged to customers based on their gross consumption, the impact of the net reserve cost to each end-user will be estimated by pro-rating the total net reserve cost to each group of end-user based on their metered quantity. In mathematical terms,

$$Net\ Reserve\ Cost_{EndUser} = Net\ Reserve\ Cost_{System} \times \frac{MQ_{EndUser}}{MQ_{System}}$$

Eq. 15

9 Section 2.5

Where,
Net Reserve Cost – additional payment (in PHP) to ancillary services providers required to cover the variability of intermittent RE resources
MQ – actual consumption (in MWh) of the system or end-user, or "Metered Quantity"

The rate impact would be determined by dividing the reserve cost impact of each end-user group by their respective metered quantities. In this study, the cost of regulating reserves would only be recovered from Luzon and Visayas end-users since it was assumed that the additional intermittent RE resources are located within the Luzon and Visayas grids.

RESULTS

This section provides the results of the simulations using the methodology discussed in the previous section. This section is divided into three (3) parts: energy cost impact, reserve cost, and overall financial impact.

ENERGY COST IMPACT

To illustrate the effect of the consideration of bilateral contract quantities and the secondary cap to the energy cost impact of the integration of intermittent RE resources to the grid, simulations were performed under the following spot conditions:

No.	Spot Quantity	Spot Price
1	No contracts	No Secondary Cap
2	Actual (2014)	No Secondary Cap
3	Actual (2014)	With Secondary Cap

Table 6 Different spot conditions used in the simulations

Scenario 1: 337 Wind

This section provides the results of the simulation when 337 MW of installed wind capacity is integrated to the grid under the different spot conditions presented in Table 6. Table 7, Table 8, and Table 9 provide the results of the simulation for each price condition.

Billing Period	Wind Gen, MWh [A]	Spot Cost w/o Wind, M PHP [B]	Spot Cost w/ Wind, M PHP [C]	MOE Impact, M PHP [D=B-C]	FIT Diff., M PHP [E]	Overall Impact, M PHP [F=D+E]
1	113,356	6,836	3,855	2,982	(892)	**2,090**
2	108,509	8,560	7,461	1,099	(761)	**337**
3	113,063	27,587	18,621	8,966	(513)	**8,453**
4	91,079	48,820	36,403	12,417	(179)	**12,238**
5	32,559	44,449	36,495	7,954	(97)	**7,857**
6	37,828	46,750	38,396	8,353	(55)	**8,299**
7	32,345	56,194	42,874	13,320	7	**13,327**
8	38,300	28,536	25,345	3,191	(143)	**3,049**

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9	34,273	22,662	20,398	2,264	(161)	**2,103**
10	43,869	15,761	13,963	1,798	(261)	**1,537**
11	69,016	19,732	16,574	3,158	(384)	**2,774**
12	82,640	14,138	10,846	3,292	(538)	**2,754**
Total	**796,836**	**340,025**	**271,231**	**68,793**	(3,977)	**64,816**

Table 7 Simulation results with 337 Wind, no contracts, and no secondary cap.

Billing Period	Wind Gen, MWh [A]	Spot w/o Wind, M PHP [B]	Spot w/ Wind, M PHP [C]	MOE Impact, M PHP [D=B-C]	FIT Diff., M PHP [E]	Overall Impact, M PHP [F=D+E]
1	113,356	710	501	208	(892)	**(684)**
2	108,509	1,116	964	152	(761)	**(610)**
3	113,063	4,082	2,700	1,382	(513)	**869**
4	91,079	5,961	4,321	1,640	(179)	**1,460**
5	32,559	4,802	3,883	919	(97)	**822**
6	37,828	5,684	4,623	1,061	(55)	**1,006**
7	32,345	7,721	5,705	2,016	7	**2,023**
8	38,300	2,506	2,239	267	(143)	**124**
9	34,273	2,662	2,352	310	(161)	**149**
10	43,869	1,958	1,734	224	(261)	**(37)**
11	69,016	2,044	1,719	325	(384)	**(59)**
12	82,640	1,522	1,221	301	(538)	**(237)**
Total	**796,836**	**40,767**	**31,962**	**8,805**	**(3,977)**	**4,828**

Table 8 Simulation results with 337 Wind, actual contracts, and no secondary cap.

Billing Period	Wind Gen, MWh [A]	Spot w/o Wind, M PHP [B]	Spot w/ Wind, M PHP [C]	MOE Impact, M PHP [D=B-C]	FIT Diff., M PHP [E]	Overall Impact, M PHP [F=D+E]
1	113,356	710	501	208	(892)	**(684)**
2	108,509	1,116	964	152	(761)	**(610)**
3	113,063	3,757	2,700	1,057	(513)	**544**
4	91,079	5,120	4,213	907	(195)	**712**
5	32,559	4,133	3,744	389	(101)	**288**
6	37,828	4,366	3,743	623	(98)	**525**
7	32,345	5,372	4,922	450	(27)	**422**
8	38,300	2,506	2,239	267	(143)	**124**
9	34,273	2,662	2,352	310	(161)	**149**
10	43,869	1,958	1,734	224	(261)	**(37)**
11	69,016	2,044	1,719	325	(384)	**(59)**
12	82,640	1,522	1,221	301	(538)	**(237)**
Total	**796,836**	**35,266**	**30,053**	**5,213**	**(4,075)**	**1,138**

Table 9 Simulation results with 337 Wind, actual contracts, and with secondary cap.

Based on the simulations, using 2014 as the reference year, the annual energy cost impact of integrating 337 MW wind into the grid is a benefit of PHP 64.8 B if there were no bilateral contract and the secondary cap was not applied. When contracts were considered, the annual energy cost benefit reduces to PHP 4.8 B only. Moreover, when the secondary cap is applied on the condition with contracts, the annual energy cost benefit further reduces to PHP 1.1 B, Which is equivalent to a 76% decrease.

Scenario 2: 337 Wind and 500 MW Solar

This section provides the results of the simulation when 337 MW of installed wind capacity and 500 MW solar capacityare integrated to the grid under the different spot conditions presented in Table 6. Table 10, Table 11, and Table 12 provide the results of the simulation for each price condition.

Billing Period	W&S Gen, MWh [A]	Spot w/o W&S, M PHP [B]	Spot w/ W&S, M PHP [C]	MOE Impact, M PHP [D=B-C]	FIT Diff., M PHP [E]	Overall Impact, M PHP [F=D+E]
1	173,666	6,836	2,109	4,727	(1,584)	**3,143**
2	168,371	8,560	6,687	1,872	(1,280)	**592**
3	176,130	27,587	13,960	13,627	(1,057)	**12,570**
4	160,602	48,820	26,791	22,029	(677)	**21,352**
5	96,479	44,449	29,502	14,947	(463)	**14,484**
6	99,812	46,750	31,360	15,389	(408)	**14,981**
7	89,769	56,194	35,647	20,546	(199)	**20,347**
8	92,013	28,536	21,209	7,327	(480)	**6,846**
9	92,688	22,662	17,351	5,311	(562)	**4,749**
10	100,482	15,761	11,749	4,012	(713)	**3,299**
11	126,505	19,732	13,977	5,755	(841)	**4,914**
12	137,684	14,138	8,979	5,159	(1,028)	**4,131**
Total	**1,514,201**	**340,025**	**219,323**	**120,701**	**(9,294)**	**111,407**

Table 10 Simulation results with 337 Wind and 500 MW Solar, no contracts, and no secondary cap.

Billing Period	Wind Gen, MWh [A]	Spot w/o Wind, M PHP [B]	Spot w/ Wind, M PHP [C]	MOE Impact, M PHP [D=B-C]	FIT Diff., M PHP [E]	Overall Impact, M PHP [F=D+E]
1	173,666	710	352	357	(1,584)	**(1,227)**
2	168,371	1,116	868	248	(1,280)	**(1,033)**
3	176,130	4,082	1,953	2,129	(1,057)	**1,072**
4	160,602	5,961	3,004	2,957	(677)	**2,279**
5	96,479	4,802	3,099	1,703	(463)	**1,240**
6	99,812	5,684	3,662	2,022	(408)	**1,614**
7	89,769	7,721	4,722	2,999	(199)	**2,800**
8	92,013	2,506	1,895	611	(480)	**130**
9	92,688	2,662	1,986	677	(562)	**115**

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10	100,482	1,958	1,438	520	(713)	**(194)**
11	126,505	2,044	1,436	608	(841)	**(233)**
12	137,684	1,522	1,049	473	(1,028)	**(555)**
Total	**1,514,201**	**40,767**	**25,465**	**15,303**	**(9,294)**	**6,009**

Table 11 Simulation results with 337 Wind and 500 MW Solar, actual contracts, and no secondary cap.

Billing Period	Wind Gen, MWh [A]	Spot w/o Wind, M PHP [B]	Spot w/ Wind, M PHP [C]	MOE Impact, M PHP [D=B-C]	FIT Diff., M PHP [E]	Overall Impact, M PHP [F=D+E]
1	173,666	710	352	357	(1,584)	**(1,227)**
2	168,371	1,116	868	248	(1,280)	**(1,033)**
3	176,130	3,757	1,953	1,804	(1,057)	**747**
4	160,602	5,120	3,004	2,116	(677)	**1,439**
5	96,479	4,133	3,099	1,034	(463)	**571**
6	99,812	4,366	3,435	930	(429)	**501**
7	89,769	5,372	4,472	900	(230)	**670**
8	92,013	2,506	1,895	611	(480)	**130**
9	92,688	2,662	1,986	677	(562)	**115**
10	100,482	1,958	1,438	520	(713)	**(194)**
11	126,505	2,044	1,436	608	(841)	**(233)**
12	137,684	1,522	1,049	473	(1,028)	**(555)**
Total	**1,514,201**	**35,266**	**24,988**	**10,278**	**(9,346)**	**932**

Table 12 Simulation results with 337 Wind and 500 MW Solar, actual contracts, and with secondary cap.

Based on the simulations, using 2014 as the reference year, the annual energy cost impact of integrating 337 MW wind and 500 MW-DC solar into the grid is a benefit of PHP 111.4 B if there were no bilateral contracts and the secondary cap was not applied. When contracts were considered, the annual energy cost benefit reduces to PHP 6.0 B. Moreover, when the secondary cap mechanism was applied on the condition with contracts, the annual energy cost benefit further reduces to PHP 0.9 B, Which is equivalent to an 84% decrease. Comparing the results with the results of the simulation with only 337 MW of wind capacity from Section 3.1.1, it may be observed that the annual benefits with an additional 500 MW of solar capacity are higher in the first (1st) two conditions. However, it may observed that the benefit under the condition that is most reflective of current operations (i.e., with contracts and secondary) is lower when an additional 500 MW of solar capacity is integrated. This may be associated with the higher FIT Rate of solar (PHP 9.68 / kWh) compared to wind (PHP 8.53 / kWh).

RESERVE COST IMPACT

This section determines if additional regulating reserves is required with the integration of intermittent RE resources to the grid and the additional cost incurred in increasing the regulating reserve requirement.

Additional Regulating Reserve Assessment

As discussed in Section 2.5, the first step in determining if the integration of intermittent RE resources to the Grid would affect the costs of end-users is to determine if additional regulating reserve is necessary. This will be performed by analyzing the forecasting error and intra-hour deviation of intermittent RE resources as well as the system demand.
For the forecasting error of intermittent RE resources, the PGC standard of 15% for the 95th percentile error will be utilized given the lack of forecast information from the existing wind and solar power plants. For the intra-hour deviation, best-fit lines were determined in accordance with the procedure described in Section 2.5. Figure 13 provides sample best-fit lines for the representative wind generating plant, while Figure 14 provides sample best-fit lines for the representative solar generating plant.

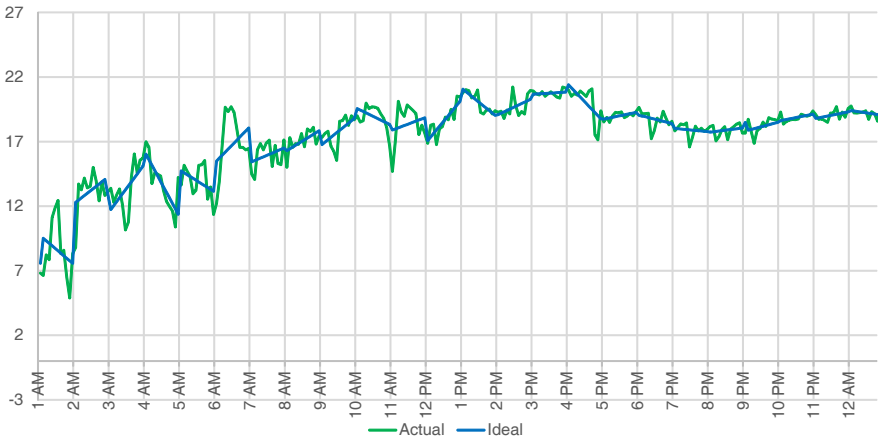

Figure 13 Sample Best-Fit Lines for 1NWIND_G01

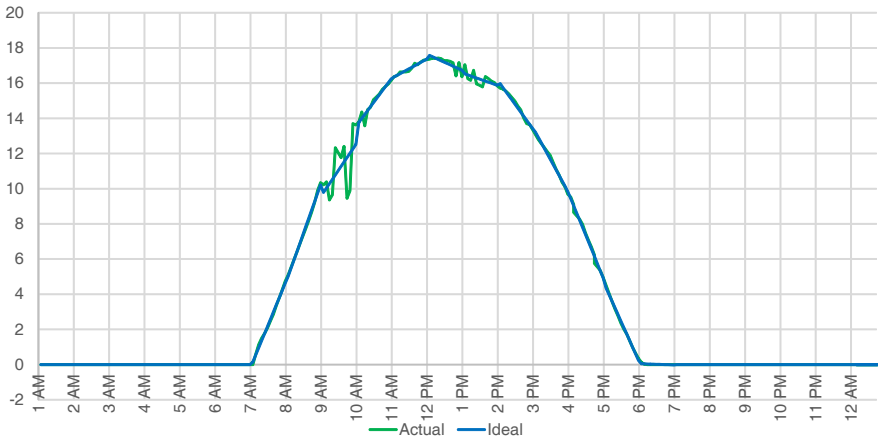

Figure 14 Sample Best-Fit Lines for 6SACASL_G01

Using the ideal curves to determine the intra-hour variations of the representative wind and solar generating plants, the value (in MW) of the 95th percentile was determined. The value of the 95th percentile was then scaled up to the assumed total installed capacities of each of the technology from the installed capacity of the representative generating plants. The results of the simulation are as follows:

Tech.	Representative Plant			Assumed Capacity	
	Capacity (MW) [A]	P95 (MW) [B]	P95 (% of Cap) [C=B/A]	Capacity (MW) [D]	P95 (MW) [E=D×C]
Wind	33.0	2.48	7.5%	337	25.3
Solar	19.8	2.59	13.1%	500	65.4

Table 13 Intra-hour deviation simulation results.

Using the methodology described above on determining the 95th percentile error, the representative wind generating plant varied by less than or equal to 2.48 MW at 95% of the time. When scaled up to the assumed capacity of 337 MW, the value of the 95th percentile becomes 25.3 MW. For solar, the 95th percentile at the assumed capacity is 65.4 MW.

For the variability of the system demand, the forecasting error may be calculated from the available data. Based on the calculations, the 95th percentile of forecasting error for system demand is 2.5% when the representative node is considered. That is, the forecasting error is equal or less than 2.5% at 95% of the time. Using the same methodology as that performed for the intermittent RE resource with regard to the determination of intra-hour variation, the value of the 95th percentile of the intra-hour variation of system demand is 1.8%. Based on these results, the total variability of system demand is ±4.3%[10]. Comparing with the current regulating reserve provision of ±2%, it may be observed that the current regulating reserve capacity is less than the estimated variability of system demand. Since the rationale for analyzing the system demand variability in relation to the current regulating reserves is only to determine if there is excess capacity that may be utilized, this study will not perform further analysis on system demand variability. A separate study may be performed with regard to the sufficiency of the current regulating reserves to address the variability of system demand.

Given that there is no excess capacity from the current regulating reserves, there is a need to augment the current regulating reserves with the integration of intermittent RE resources to the grid. Applying (Eq. 7) to determine the maximum additional regulating reserve requirement will yield the following results:

Scenario	Peak Intermittent Gen (MW) [A]	Max Forecasting Error (MW) [B=15%×A]	Max Intra-Hour Variation (MW) [C]	Max Total RE Variation (MW) [D=B+C]	Max Add'l Regulating Reserve (MW) [E=D×2]
337 MW Wind	195.2	±29.3	±25.3	±54.6	**109.2**
337 MW Wind + 500 MW Solar	580.3	±87.0	±90.7	±177.7	**355.4**

Table 14 Maximum additional regulating reserve requirement for each capacity assumption.

Cost Simulation

The results of the previous section showed that additional regulating reserve would be required with the integration of intermittent RE resources to the grid. This means that additional reserve costs will have to be estimated.

First, the capacity scheduled for each hour was determined by applying (Eq. 10). Figure 15 provides a sample of the resulting hourly schedules to address variability of wind generation.

10 2.5% Forecasting Error plus 1.8% Intra-Hour Variation

For the solar generating plants, special considerations were provided for off-peak generation since these plants will not be generating during nighttime. Figure 16 provides a sample of the resulting hourly schedules to address the variability of solar generation.

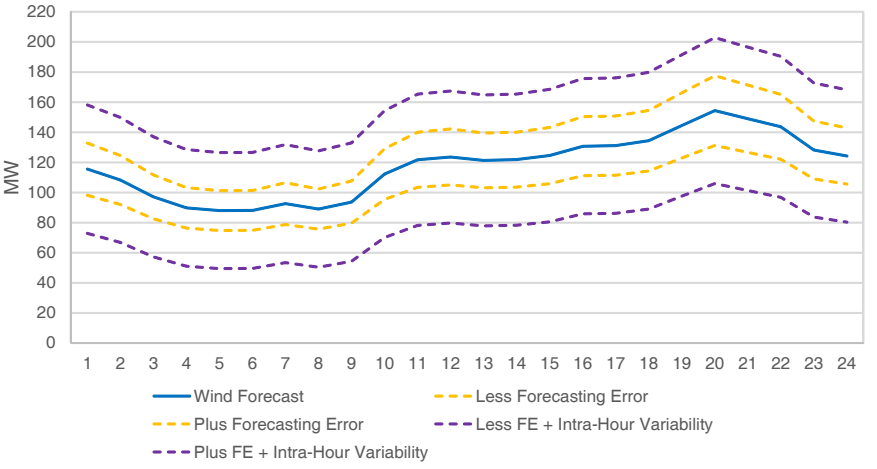

Figure 15 Sample Reserve Capacity Scheduled for Wind Generation

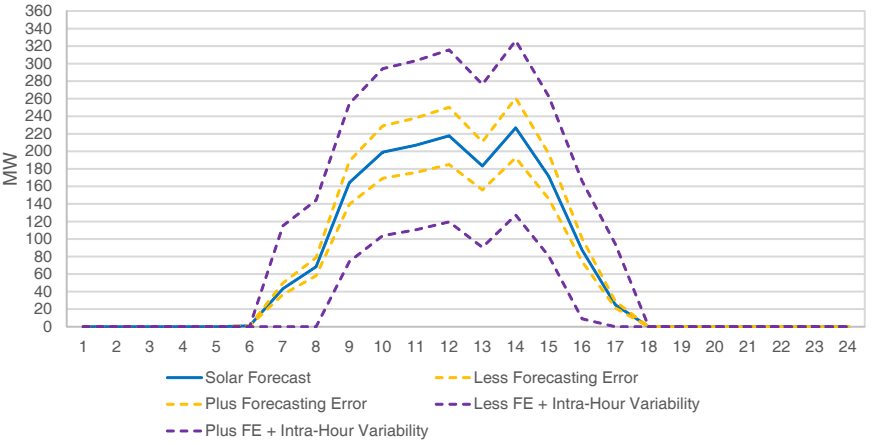

Figure 16 Sample Reserve Capacity Scheduled for Solar Generation

After determining the hourly scheduled regulating reserve capacity, the energy dispatched was determined. In this study, it was assumed that the regulating reserve will be dispatched at half its regulating reserve schedule at all times to have available capacity to address downward variation of system demand or upward variation of intermittent generation. In addition, it is assumed that the regulating reserve is required to dispatch additional energy during instances when the generation from intermittent RE resources fluctuates downward. To simplify the simulation, the average additional production per hour to address downward generation variability was calculated and spread across all hours. The following table provides the results of this calculation:

Technology	Capacity (MW)	Ave. Hourly Additional Production (MWh)
Wind	337	3.5
Solar	500	5.5

Table 15 Average hourly additional production for each technology.

Using the above results together with the assumed ASPA rate and simulated spot prices, the net reserve cost for each scenario under conditions with and without the application of the secondary cap were simulated [11]. Table 16 provides the results without secondary cap.

Billing Period	Scenario 1: Wind Only			Scenario 2: Wind and Solar		
	ASPA Cost [A]	WESM Revenue [B]	Net Reserve Cost [C=A+B]	ASPA Cost [D]	WESM Revenue [E]	Net Reserve Cost [F=D+E]
1	(164)	18	**(146)**	**(332)**	(19)	**(351)**
2	(162)	45	**(117)**	**(342)**	83	**(259)**
3	(153)	107	**(46)**	**(319)**	164	**(155)**
4	(154)	180	0	**(342)**	282	**(60)**
5	(124)	138	0	**(303)**	254	**(49)**
6	(130)	156	0	**(316)**	290	**(26)**
7	(124)	193	0	**(303)**	379	**0**
8	(130)	108	**(22)**	**(311)**	211	**(99)**
9	(128)	88	**(41)**	**(311)**	177	**(134)**
10	(129)	61	**(68)**	**(297)**	113	**(184)**
11	(144)	77	**(67)**	**(316)**	135	**(181)**
12	(146)	53	**(94)**	**(313)**	76	**(236)**
Total	**(1,688)**	**1,223**	**(600)**	**(3,803)**	**2,145**	**(1,735)**

Table 16 Net reserve cost (in M PHP) of each scenario without secondary cap.

Based on the simulation, using 2014 as the reference year, the annual additional cost for reserves when 337 MW of wind is integrated to the grid and the secondary cap is not applied is PHP 0.6 B. For the scenario with 337 MW wind and 500 MW solar, the annual additional cost for reserves is PHP 1.74 B. Table 17 then provides the results with secondary cap.

Billing Period	Scenario 1: Wind Only			Scenario 2: Wind and Solar		
	ASPA Cost [A]	WESM Revenue [B]	Net Reserve Cost [C=A+B]	ASPA Cost [D]	WESM Revenue [E]	Net Reserve Cost [F=D+E]
1	(164)	18	**(146)**	**(332)**	(19)	**(351)**
2	(162)	45	**(117)**	**(342)**	83	**(259)**
3	(153)	107	**(46)**	**(319)**	164	**(155)**
4	(154)	174	0	**(342)**	282	**(60)**
5	(124)	134	0	**(303)**	254	**(49)**
6	(130)	132	0	**(316)**	277	**(39)**
7	(124)	170	0	**(303)**	361	**0**
8	(130)	108	**(22)**	**(311)**	211	**(99)**
9	(128)	88	**(41)**	**(311)**	177	**(134)**
10	(129)	61	**(68)**	**(297)**	113	**(184)**

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11 Spot quantity conditions do not affect the calculation of the net reserve cost

11	(144)	77	**(67)**	**(316)**	135	**(181)**
12	(146)	53	**(94)**	**(313)**	76	**(236)**
Total	**(1,688)**	**1,169**	**(600)**	**(3,803)**	**2,114**	**(1,748)**

Table 17 Net reserve cost (in M PHP) of each scenario with secondary cap.

Based on the simulation, using 2014 as the reference year, the annual additional cost for reserves when 337 MW of wind is integrated to the grid and the secondary cap is applied is still PHP 0.6 B. For the scenario with 337 MW wind and 500 MW solar, the annual additional cost for reserves is marginally higher at PHP 1.75 B.

TOTAL FINANCIAL IMPACT

To determine the total financial impact of the integration of intermittent RE resources for a year, using 2014 as the reference, the energy cost impact calculated in Section 3.1 and the reserve cost impact calculated in Section 3.2 are aggregated. For this summary, only the conditions with consideration of bilateral contracts are considered since they reflect current operations. Table 18 provides the total financial impact without secondary cap, while Table 19 provides the total financial impact with secondary cap.

Scenario	Energy Cost Impact (M PHP)	Reserve Cost Impact (M PHP)	Total Financial Impact (M PHP)
337 MW Wind	4,828	(600)	4,228
337 MW Wind + 500 MW Solar	6,009	(1,735)	4,274

Table 18 Total financial impact of each scenario, with contracts, and without secondary cap.

Scenario	Energy Cost Impact (M PHP)	Reserve Cost Impact (M PHP)	Total Financial Impact (M PHP)
337 MW Wind	1,138	(600)	538
337 MW Wind + 500 MW Solar	932	(1,748)	**(816)**

Table 19 Total financial impact of each scenario, with contracts, and with secondary cap.

Based on the calculations using 2014 as the reference year, the total annual financial impact to end-users when 337 MW of wind capacity is integrated to the grid is a benefit of PHP 4.2 B if the secondary cap is not applied. On the other hand, If the secondary cap is applied, the annual benefit decreases to PHP 0.5 B. For the scenario where an additional 500 MW of solar capacity is integrated on top of the 337 wind capacity, the annual financial impact to end-users is a benefit of PHP 4.3 B without the secondary cap. If the secondary cap is applied, the annual financial impact becomes an additional cost to the end-users amounting to PHP 0.8 B.

END-USER FINANCIAL IMPACT

This section provides the results of the calculation of the financial impact to the end-users based on the following groups: a large private distribution utility in Luzon, Rest of Luzon and Visayas, and Mindanao. For this study, the condition considered in determining the financial impact is that with bilateral contracts and with secondary applied. This was selected since it reflects the current conditions in the WESM.

Energy Cost Impact

As mentioned in Section 2.7.1, the cost impact to specific groups of end-users is affected by their respective spot exposures since the Merit Order Effect impact only applies to spot quantities. On the other hand, the FIT differential is recovered from the gross consumption of the end-users. Table 20 provides the results of the calculations with 337 MW wind, contracts, and secondary cap.

Scenario	Quantity Share (%)		End-User Energy Cost Impact (M PHP)		
	Spot	MQ	MOE	FIT Diff.	Total
LPDU	26.6%	42.9%	1,417	(1,752)	**(335)**
Rest of L& V	73.6%	44.9%	3,796	(1,813)	**1,983**
Mindanao	0.0%	12.2%	0	(510)	**(510)**
TOTAL	100.0%	100.0%	5,213	(4,075)	**1,137**

Table 20 Energy cost impact to end-users with 337 MW wind, contracts, and secondary cap.

The above table indicates that the total annual energy cost impact to the large private distribution utility in Luzon is an additional cost of PHP 335 M with Mindanao also incurring an additional cost of PHP 510 M. On the other hand, the rest of Luzon and Visayas is estimated to have an annual benefit amounting to PHP 1,983 M.

Table 21 then provides the results of the calculations with 337 MW wind and 500 MW solar, with contracts and secondary cap.

Scenario	Quantity Share (%)		End-User Energy Cost Impact (M PHP)		
	Spot	MQ	MOE[12]	FIT Diff.[13]	Total
LPDU	26.6%	42.9%	2,772	(4,016)	**(1,245)**
Rest of L& V	73.6%	44.9%	7,507	(4,171)	**3,335**
Mindanao	0.0%	12.2%	0	(1,158)	**(1,158)**
TOTAL	100.0%	100.0%	10,278	(9,346)	**932**

Table 21 Energy cost impact to end-users with 337 MW wind and 500 MW solar, with contracts and secondary cap.

Based on the calculations for the scenario with 337 MW wind and 500 MW solar, the same trend may be observed. The above table indicates that the total annual energy cost impact to the large private distribution utility in Luzon is an additional cost of PHP 1,245 M with Mindanao also incurring an annual additional cost of PHP 1,158 M with no benefit from the MOE. On the other hand, the rest of Luzon and Visayas is estimated to have an annual benefit amounting to PHP 3,335 M.

Using the above figures, the rate impact to each end-user may be calculated (Table 22).

12 Pro-rated PHP 10,278 M based on spot share
13 Pro-rated (PHP 9,346 M) based on MQ share

Scenario	Total Energy Cost Impact (M PHP)		Rate Impact (PHP / kWh)	
	Wind Only	Wind and Solar	Wind Only	Wind and Solar
LPDU	(335)	(1,245)	**(0.012)**	**(0.043)**
Rest of L& V	1,983	3,335	**0.065**	**0.110**
Mindanao	(510)	(1,158)	**(0.062)**	**(0.140)**
TOTAL	1,137	932	**0.017**	**0.014**

Table 22 Energy cost rate impact to end-users for each scenario with contracts and secondary cap.

From the above table, the rate impact due to changes in energy costs to the large private distribution utility in Luzon is an additional cost of 1.2 centavos per kWh on average for the year if 337 MW of wind is integrated to the grid. The additional cost increases to 4.3 centavos per kWh on average if an additional 500 MW of solar capacity is integrated. For the rest of Luzon and Visayas, the integration of 337 MW of wind results to a benefit of 6.5 centavos per kWh on average for the year, which increases to 11 centavos per kWh on average if an additional 500 MW of solar capacity is further integrated. For Mindanao, the additional cost is 6.2 centavos per kWh on average with 337 MW of wind capacity and 14 centavos per kWh on average with an additional 500 MW of solar capacity.

Reserve Cost Impact

Since the assumed intermittent RE resources were located within the Luzon and Visayas grids, the reserve cost impact will only affect Luzon and Visayas end-users. Table 23 provides the calculation of the total reserve cost and rate impact to the different end-users with secondary cap.

Scenario	Total Reserve Cost Impact (M PHP)		Rate Impact (PHP / kWh)	
	Wind Only[14]	Wind and Solar[15]	Wind Only	Wind and Solar
LPDU	(293)	(854)	(0.010)	(0.029)
Rest of L& V	(306)	(893)	(0.010)	(0.029)
Mindanao	0	0	0	0
TOTAL	**(600)**	**(1,735)**	**(0.010)**	**(0.029)**

Table 23 Reserve cost and rate impact to end-users for each scenario with secondary cap.

According to the calculations, the rate impact to the large private distribution utility in Luzon and the rest of Luzon and Visayas is the same at 1 centavo per kWh on average for the year, if 337 MW wind capacity is integrated to those grids. If an additional 500 MW solar capacity is integrated, the impact on the large private distribution utility in Luzonand the rest of Luzon and Visayas is 2.9 centavos per kWh on average.

14 Pro-rated (PHP 600 M) based on MQ
15 Pro-rated (PHP 1,735 M) based on MQ

Total Financial Impact

The total financial impact may be determined by adding the energy cost impact and reserve cost impact for each end-user. Table 24 provides the total financial impact of the integration of 337 MW wind for each end-user with contracts and secondary cap.

	Energy Cost Impact (M PHP)	Reserve Cost Impact (M PHP)	Total Financial Impact (M PHP)	Rate Impact (PHP/kWh)
LPDU	(335)	(293)	(628)	**(0.021)**
Rest of L& V	1,983	(306)	1,677	**0.055**
Mindanao	(510)	0	(510)	**(0.062)**
TOTAL	1,137	(600)	538	**0.008**

Table 24 Total financial impact to end-users with 337 MW wind, contracts, and secondary cap.

Based on the calculations, the total rate impact of integrating 337 MW of wind capacity to the grid to the large private distribution utility in Luzon is an additional cost of 2.1 centavos per kWh on average for the year. Similarly, the integration of the wind capacity would result to an additional cost of 6.2 centavos per kWh on average for Mindanao. On the other hand, the rest of Luzon and Visayas will be receiving a benefit of 5.5 centavos per kWh on average with the integration of the wind capacity.

Table 25 then provides the total financial impact of the integration of 337 MW wind and 500 MW solar for each end-user with contracts and secondary cap.

	Energy Cost Impact (M PHP)	Reserve Cost Impact (M PHP)	Total Financial Impact (M PHP)	Rate Impact (PHP/kWh)
LPDU	(1,245)	(854)	(2,098)	**(0.072)**
Rest of L& V	3,335	(893)	2,442	**0.081**
Mindanao	(1,158)	0	(1,158)	**(0.140)**
TOTAL	932	(1,735)	(816)	**(0.012)**

Table 25 Total financial impact to end-users with 337 MW wind and 500 MW solar, contracts, and secondary cap.

With the additional 500 MW solar capacity, the additional cost to the large private distribution utility in Luzon increases to 7.2 centavos per kWh on average for the year. Correspondingly, the benefit to the rest of Luzon and Visayas increases to 8.1 centavos per kWh on average. Lastly, the additional cost of Mindanao also increases to 14 centavos per kWh on average.

ANALYSIS

This section provides some analysis on the results of the simulations conducted.

EFFECT OF SECONDARY CAP

One of the items analyzed in the simulations is the effect of the secondary cap to the financial impact of the integration of intermittent RE resources to the grid. Table 26 provides the summary of the total financial impacts with and without the application of the secondary cap.

Scenario	Total Financial Impact (M PHP)		Effect of Secondary Cap (M PHP)
	Without SC	With SC	
337 MW Wind	4,228	538	(3,690)
337 MW Wind + 500 MW Solar	4,274	(816)	(5,090)

Table 26 Effect of the secondary cap to the financial impact of each scenario.

From the above table, it may be observed that the secondary cap significantly reduces the benefits from the integration of intermittent RE resources to the grid. In fact, the application of the secondary cap results to an additional cost when 337 MW of wind and 500 MW of solar capacities are integrated.

Further analysis of the simulated data showed that the secondary cap affects the financial impact of the integration of intermittent RE resources due to the following:

a. Application of the secondary cap decreases the price reduction resulting from the merit order effect; and
b. Reduction of WESM revenues resulting to higher FIT differential payments.

Figure 17 provides an illustration of the above effects. In the illustration, the solid lines represent the 7-day rolling average of the prices without the secondary cap, while the dashed lines represent the 7-day rolling average of the prices with the secondary cap. Due to the secondary cap, it may be observed that the dashed lines never go beyond the threshold (red solid line).

As indicated by the first group of arrows (left side), one of the effects of the secondary cap to the financial impact of the integration of intermittent RE resources to the grid is the smaller benefit from the merit order effect, which is proportional to the price decrease from the dashed blue line to the solid green line. This is relative to having a benefit proportional to the price decrease from the solid blue line to the solid green line without the secondary cap. The second group of arrows then indicates the increase in FIT differential due to the secondary cap. In an example where there is solar generation, there would be no additional FIT differential payment by the end-users since the price (solid blue line) is higher than the solar FIT rate (solid yellow line). However, when the secondary cap is applied, additional FIT differential payment is required since the capped prices (dashed blue line in the figure below) is now lower than the solar FIT rate (solid yellow line in the figure below). Furthermore, the FIT-All Fund will be depleted on a faster rate since the financial model assumes higher WESM average rate and this was not met in the simulated WESM prices.

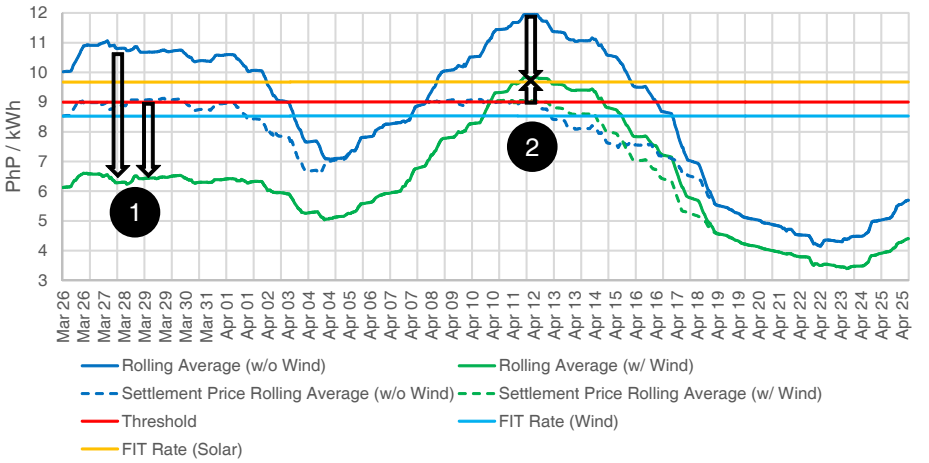

Figure 17 Illustration of the Effect of Secondary Cap to the Financial Impact

EFFECT OF ADDITIONAL 500 MW SOLAR

From Table 18 and Table 19, the total annual financial impact of the integration of intermittent RE resources with and without secondary cap is as follows:

Scenario	Total Financial Impact (M PHP)	
	No Secondary Cap	With Secondary Cap
337 MW Wind	4,228	538
337 MW Wind + 500 MW Solar	4,274	**(816)**
Difference	**46**	**(1,354)**

Table 27 Total financial impact of each scenario, with contracts.

Based on the figures, the addition of 500 MW solar affects the total annual financial impact differently depending on the application of the secondary cap. Without the secondary cap, the addition of 500 MW solar capacity is an additional benefit of PHP 46 M (1.09%). On the other hand, application of the secondary cap would result to an additional cost of PHP 1.35 B with the additional 500 MW solar capacity. To determine the reason behind the change in the financial impact of the additional 500 MW of solar capacity, each cost component affected is analyzed. Table 28 provides the change in each cost component with the additional 500 MW solar capacity without secondary cap.

	337 MW Wind	337 MW Wind + 500 MW Solar	Difference
Energy Cost	4,828	6,009	**1,181**
FIT Differential	(3,977)	(9,294)	**(5,317)**
Merit Order Effect	8,805	15,303	**6,498**
Reserve Cost	(600)	(1,735)	**(1,135)**
Total Impact	**4,228**	**4,274**	**46**

Table 28 Per-Cost Component Impact of each scenario, with contracts, and without secondary cap.

Without the secondary cap, analysis of the cost components indicates that the addition of 500 MW solar capacity results to a benefit of PHP 1.18 B in terms of energy costs. Although the FIT rate for solar is higher at PHP 9.68 / kWh, the additional benefit derived from the merit order effect was able to offset the additional costs from the FIT differential. Due to higher reserve costs with the 500 MW solar capacity, however, the additional benefit expected to be derived with the addition of 500 MW solar decreases to only PHP 46 M. Table 29 then provides the change in each cost component with the additional 500 MW solar capacity without secondary cap.

	337 MW Wind	337 MW Wind + 500 MW Solar	Difference
Energy Cost	1,138	932	**(206)**
FIT Differential	(4,075)	(9,346)	**(5,271)**
Merit Order Effect	5,213	10,278	**5,065**
Reserve Cost	(600)	(1,748)	**(1,148)**
Total Impact	**538**	**(816)**	**(1,354)**

Table 29 Per-Cost Component Impact of each scenario, with contracts, and with secondary cap.

With the secondary cap, analysis of the cost components indicates that the addition of 500 MW solar capacity results to an additional cost of PHP 206 M in terms of energy cost. This may be attributed to the lower spot prices due to the secondary cap resulting to higher FIT differential (PHP 9,294 M to PHP 9,346 M) compounded with the decrease in spot price reductions (PHP 15,303 M to PHP 10,278 M). On the other hand, the additional reserve costs with the 500 MW solar capacity remains approximately the same at PHP 1,748 M. Given the additional cost now associated with the energy cost and the expected additional cost for reserves, the total impact with the addition of 500 MW solar is an additional cost.

EFFECT OF END-USER SPOT EXPOSURE

During the simulation of the financial impact to each group of end-users in Section 3.4, it was observed that, although the total energy cost impact is an annual benefit of PHP 1.1 B, it is not across the board benefit for all of the end-users. In Table 20, it is shown that the integration of 337 MW wind is an additional cost for the large private distribution utility in Luzon and Mindanao. For the large private distribution utility in Luzon, the additional cost is due to its low exposure to the WESM (3.83% last 2014), which results to a low impact of the merit order effect, and its high gross consumption (42.9% of the whole system), which results to a high share of the FIT differential. In contrast, the higher spot exposure of the rest of Luzon and Visayas (10.58%) was found to fully offset its FIT differential payment and even provide a benefit to that group of end-users.

For Mindanao, it does not experience the merit order effect since there is no WESM in the region. Thus, the integration of intermittent RE resources would always result to an additional cost to the region equivalent to its FIT differential payment.

CONCLUSIONS

Using the data from 2014, the annual financial impact of integrating 337 MW wind capacity and an additional 500 MW solar capacity under conditions that best reflect actual operations (i.e., actual contracts and with secondary cap) was estimated to be a benefit of PHP 538 M if 337 MW wind capacity is integrated into the grid, but an additional cost of PHP 816 M if 337 MW of wind capacity and 500 MW of solar capacity were integrated into the grid. Table 30 provides the breakdown of the annual financial impact of each scenario.

Scenario	Energy Cost Impact (M PHP)	Reserve Cost Impact (M PHP)	Total Financial Impact (M PHP)
337 MW Wind	1,138	(600)	**538**
337 MW Wind + 500 MW Solar	932	(1,748)	**(816)**

Table 30 Total financial impact of each scenario, with contracts, and with secondary cap.

The total financial impact, however, was found to vary when distributed to each group of end-users. Table 31 provides the results of the calculation of the financial impact to groups of end-users. From the table, the annual rate impact to the large private distribution utility from Luzon is an additional cost of 2.1 centavos per kWh if 337 MW of wind capacity were integrated. For the rest of Luzon and Visayas end-users, the impact is a benefit of 5.5 centavos per kWh under the same scenario, while it is also an additional cost of 6.2 centavos per kWh for the Mindanao end-users. When 500 MW of solar capacity was considered, together with 337 MW of wind capacity, the rate impact to the large private distribution utility in Luzon increases to 7.2 centavos per kWh. The additional cost of Mindanao end-users also increases to 14 centavos per kWh, while the benefit to the rest of Luzon and Visayas also increases to 8.1 centavos per kWh.

End-Users	Scenario 1: Wind Only		Scenario 2: Wind and Solar	
	Total Financial Impact (M PHP)	Rate Impact (PHP/kWh)	Total Financial Impact (M PHP)	Rate Impact (PHP/kWh)
LPDU	(628)	(0.021)	(2,098)	(0.072)
Rest of L& V	1,677	0.055	2,442	0.081
Mindanao	(510)	(0.062)	(1,158)	(0.140)
TOTAL	538	0.008	(816)	(0.012)

Table 31 Total financial impact to end-users for each scenario with contracts and secondary cap.

The variation in the financial impact to each end-user group was found to be a result of the differences in the spot exposure of each group. With a lower exposure to the WESM, the benefit from the merit order effect is also lower, which is the case for the large private distribution utility in Luzon. Given the size of the large private distribution utility in Luzon's gross consumption, however, its benefit derived from the merit order effect is not enough to offset its additional FIT differential payments. The converse may be observed for the rest of Luzon and Visayas where exposure to spot market is higher. Lastly, the merit order effect has no impact on Mindanao since the region has no WESM.

Based on additional analysis on the impact of the secondary cap, it was observed that the application of the secondary cap would result to lower benefits derived from the integration of intermittent RE resources to the grid. The reduction was found to be a result of the following:

a. Application of the secondary cap decreases the price reduction resulting from the merit order effect; and
b. Reduction of WESM revenues resulting to higher FIT differential payments.

In terms of the actual monetary transactions related to the costs of the integration of intermittent RE resources, the FIT differential and reserve cost payments would be charged to the end-users uniformly. Assuming the current 3.2 centavos per kWh[16] FIT differential rate uniformly charged to all end-users, all end-users would be charged an additional 2.8 centavos per kWh, if 337 MW wind capacity is integrated, and an additional 10.6 centavos per kWh, if an additional 500 MW solar capacity were integrated, under the FIT-All line item. In addition, the end-users from the Luzon and Visayas grids would also be charged an additional 1 centavo per kWh, if 337 MW wind capacity is integrated, and 2.9 centavos per kWh, if an additional 500 MW solar capacity were integrated, under transmission charges for the additional regulating reserve costs.

In contrast, the impact of the merit order effect may only be identified with further analysis of the WESM payments of each end-user. For the large private distribution utility in Luzon, further analysis of its WESM payments would indicate that it would be paying 4.9 centavos per kWh less than what it would have paid if the 337 MW wind capacity were not available. In the scenario with 337 MW wind capacity and 500 MW solar capacity, further analysis of its WESM payments would indicate that it would be paying 9.5 centavos per kWh less than what it would have paid if those intermittent RE resources were not available. For the rest of Luzon and Visayas, further analysis of its WESM payments would indicate that it would be paying 12.5 centavos per kWh less than what it would have paid if the 337 MW wind capacity were not available. In the scenario with 337 MW wind capacity and 500 MW solar capacity, further analysis of its WESM payments would indicate that it would be paying 24.7 centavos per kWh less than what it would have paid if those intermittent RE resources were not available. For end-users from Mindanao, no impact from the merit order effect will be identified since the WESM is not implemented in the region.

16 Out of the total 4 centavos per kWh FIT-All rate

APENDIX A

ALGORITHM FOR FINDING THE BEST-FIT LINE

This appendix provides the algorithm used in the determination of the best-fit line for the 5-minute snapshots for each interval. The explanation provided below is an excerpt from the following source:

Algorithm for Finding the Best-Fit Line (faculty.cs.niu.edu/~hutchins/csci230/best-fit.htm)

Suppose we have a set of points (more than one) in the X-Y plane. Usually there will not be a line that actually does go through all of them. We want to find the line that comes closest to passing through all the points. Each point has coordinates (X, Y). We read through all the points in the set and calculate the following:

Count = the number of points
SumX = sum of all the X values
SumY = sum of all the Y values
SumX2 = sum of the squares of the X values
SumXY = sum of the products X*Y for all the points
Now we can find the slope M and Y-intercept YInt of the line we want:
XMean = SumX / Count
YMean = SumY / Count
Slope = (SumXY - SumX * YMean) / (SumX2 - SumX * XMean)
YInt = YMean - Slope * XMean
The equation for the line is:
Y = Slope * X + YInt

APPENDIX B

CONFIGURATION OF THE PVWATTS© CALCULATOR

This appendix provides the configuration used in the PVWatts© Calculator for the determination of the hourly solar generation profile.

Parameter	Value	Remarks
Location:	GUAM, HI	No weather data available for the Philippines. Guam was selected since it has the same latitude as the Philippines (Batangas City)
Lat (deg N):	13.55	
Long (deg E):	144.83	
Elev (m):	110	
Module Type:	Standard	
Array Type:	Fixed (open rack)	
Array Tilt (deg):	11	
Array Azimuth (deg):	180	
System Losses:	14	
Inverter Efficiency:	96	


ABB
ABB

2

THE COMPETITION BILLS *- and the -* WHOLESALE ELECTRICITY SPOT MARKET

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ABSTRACT

The paper provides an overview of the competition related provisions in the EPIRA and the competition bills pending in both Houses of Senate and Representatives. The implied and express repeals provided in the bills in relation to the EPIRA show that the bills affect the ability of the state to prohibit excessive pricing in the electric power industry, as both bills deal with market power abuse focused on exclusionary conduct.

Key Terms: competition, excessive pricing, exclusionary conduct, market power abuse

INTRODUCTION: DEREGULATION AND COMPETITION

The economic theory behind free markets is to achieve a competitive equilibrium, that would maximize overall efficiency. As stated by Stoft:

> *"The plan of deregulation is to achieve efficiency through competition. Economics guarantees this result provided that market reaches a classic competitive equilibrium. This requires at least three conditions to be met: price taking suppliers, public knowledge of the market price, and well-behaved production costs."*[1]

Efficiency in this context can be defined as meaning,"(1) the output is produced by the cheapest suppliers, (2) it is consumed by those most willing to pay for it, and (3) the right amount is produced".[2]

This is not to say however, that deregulated markets are perfectly competitive, or that regulated markets do not work. The problem with regulation however, lies with the fact that suppliers know the market better, forcing regulators to make trade-offs. Unlike truly competitive markets, regulation can either provide incentives to (i) hold price down to marginal cost or (ii) minimize cost, but not both.[3] For example, one can choose a return-on-rate base regime where suppliers are assured they will recover all costs, but no more, which provides no incentive for them to minimize cost. On the other hand, one can choose to use price caps where there is an incentive to minimize actual costs through higher efficiency. However, setting a proper price cap assumes that the regulator is perfectly aware of all information to make optimal decisions. In the absence of enough information, the regulator may be forced to choose caps higher than long run costs to avoid bankrupting suppliers.[4]

Competition laws generally focus on preventing collusion among suppliers (anti-competitive agreements effectively creating cartels) as well as exclusionary behavior (abuse of dominant position by attempting to monopolize the market).[5] Mergers and acquisitions are also regulated because of the risk of concentrating market power in too few dominant suppliers effectively eliminating competition. In the absence of exclusionary behavior, laws do not prohibit firms from setting very high prices or charging what the market can bear since market

1 S. Stoft, Power System Econimics: Designing Markets for Electricity 50 (2002)
2 Id., at 53
3 Id., at 11
4 Id.
5 See the Sherman Act for the United States and the OECD Policy Round Tables: Excessive Pricing 2011 (7 February 2012) which provides submissions on the discussion of excessive pricing

forces are expected to automatically "correct" imbalances in supply-demand. When profits in an industry exceed normal expectations, it will attract more players boosting supply and ultimately drive prices down.

Such laws generally do not provide for intervention when prices become excessive as long as exclusionary behavior and collusion are absent. There may however be adequate reasons for price intervention, for example, when critical to society. Entry barriers and natural market conditions may make it easier to gain and preserve monopoly power because of the small number of firms, previous state owned monopolies preserved through political patronage or corruption. The industry structure may not be able to evolve, the market may not be able to remedy itself and dominant positions cannot be eroded.[6]

THE EPIRA

RESTRUCTURING THE ELECTRIC POWER INDUSTRY

On 8 June 2001, then President Gloria Macapagal-Arroyo signed into law Republic Act No. 9136 otherwise known as the Electric Power Industry Reform Act of 2001 (EPIRA), restructuring the entire electric power industry for the purpose of introducing *"higher efficiency, greater innovation and end-user choice"* .[7] Restructuring, as defined in the EPIRA, would be *"understood as covering a range of alternatives enhancing exposure of the industry to competitive market forces".*[8]

As with other restructured electricity markets in other countries, EPIRA was concerned with long-term benefits for the consumer[9] by making changes in the electric power industry's regulatory framework. Joskow clearly articulates the goals for restructuring as follows:

> *"The overriding reform goal has been to create new governance arrangements for the electricity sector that provide long-term benefits to consumers. These benefits are to be realized by relying on competitive wholesale markets for power to provide better incentives for controlling construction and operating costs of new and existing generating capacity, to encourage innovation in power supply technologies, and to shift the risks of technology choice, construction cost and operating "mistakes" to suppliers and away from consumers."*[10]

To put into context the decision making for construction of power plants and their associated risks, one needs to examine the factual circumstances prior to the EPIRA's enactment. Reacting to an earlier energy crisis and spurred by strong economic growth, by 1997 the Philippine government had made arrangements for thirty seven (37) Independent Power Producer (IPP) contracts accounting for forty percent (40%) of its generation capacity.[11] When the bust occurred at the onset of the Asian Financial Crisis, state-owned National Power Corporation (NPC) found itself financially burdened by onerous take-or-pay clauses

6 OECD Policy Round Tables: Excessive Pricing 2011, 36 (7 February 2012)
7 EPIRA, Section 4, (rr)
8 EPIRA, Section 4, (rr)
9 EPIRA, Section 2(a) and 2(b)
10 P. Joskow, Introduction to Electricity Sector Liberalization: Lessons Learned from Cross-Country Studies, in ELECTRICITY MARKET REFORM: AN INTERNATIONAL PERSPECTIVE 3 (2006)
11 X. Wu, P. Sulistiyanto, Independent Power Producer (IPP) Debacle in Indonesia and the Philippines: Path Dependence and Spillover Effects at http://lkyspp.nus.edu.sg/wp-content/uploads/2013/03/IPP_debacle1.pdf last accessed on 4 February 2015

requiring payment for energy demand that was no longer required.[12] In 1998, NPC debts were reported to be at USD Five Billion.[13] The debt burden is still felt today through the imposition of the Universal Charge on consumers which NPC reports to be at PHP0.19 per kWh.[14]

It became clear to policy makers at that time that reform was necessary to push the risk away from the government/consumers to those who would be in the best position to manage the same, while ensuring security of supply. Taking its cue from reforms made in other countries such as the United Kingdom, New Zealand, Australia and Argentina, the Philippines would rely on a competitive market to produce the most efficient result. It would do so by restructuring the industry through the EPIRA as summarized in Table 1 below.

Features[15]	EPIRA Provisions
"Vertical separation of competitive and regulated monopoly sectors to facilitate competition and regulation."	• Division of the electric power industry into generation, supply, transmission and distribution sectors.[16]
"Designation of an independent system operator to maintain network stability and facilitate competition."	• Creation of the National Transmission Corporation (TRANSCO) to assume the transmission functions of NPC.[17]
"Application of regulatory rules to promote access to the transmission network and incentivize efficient location and interconnection of new generation facilities."	• TRANSCO is mandated to provide open and non-discriminatory access to transmission.[18]
"Privatization to enhance performance and reduce the ability of the state to use these enterprises to pursue costly political agendas."	• Creation of the Power Sector Assets and Liabilities Management Corporation (PSALM)[19] to privatize the assets of NPC.[20]
"Horizontal restructuring to create an adequate number of competing generators and suppliers."	• Removal of 60% Filipino nationality requirement in the ownership of generating companies.[21]
"Creation of ...energy and ancillary services markets and trading arrangements, including contract markets and real-time balancing of the system."	• Establishment of the wholesale electricity spot market (WESM).[22]
"Unbundling of retail tariffs and rules to enable access to the distribution networks in order to promote competition at the retail level."	• Functional and structural unbundling of business activities and rates in accordance with the four sectors (generation, supply, transmission and distribution).[23] Creation of retail competition and open access on the distribution side.[24]

(continues to next page)

12 Id.
13 As reported by then President Puno, of the National Power Corporation in a meeting of the Committee on Energy on 3 December 1998 (transcripts, p. 0230)
14 http://www.napocor.gov.ph/index.PHP/infographics/universal-charge last accessed on 4 February 2015
15 S. Littlechild, Foreword: The Market versus Regulation, in Electricity Market Reform: An International Perspective xviii (2006)
16 EPIRA, Section 5
17 EPIRA, Sections 8-21
18 EPIRA, Section 9
19 EPIRA, Section 49
20 EPIRA, Sections 47, 50
21 EPIRA, Section 6
22 EPIRA, Section 30
23 EPIRA, Section 36
24 EPIRA, Section 31

Features	EPIRA Provisions
"Specification of arrangements for supplying customers until retail competition is in place."	• Rates charged by distribution utilities for supply of electricity to the captive market are subject to regulation by the Energy Regulatory Commission (ERC).[25]
"Creation of independent regulatory agencies with adequate information, staff and powers, and duties to implement incentive regulation and promote competition."	• Creation of the ERC.[26] • While not mentioned in the EPIRA itself, it created structural changes within the Department of Energy which included the creation of the Electric Power Industry Management Bureau.[27]

SAFEGUARDING THE MARKET: EPIRA, SECTION 45

Unlike other markets, electricity markets are more susceptible to the exercise of market power.[28] To illustrate, if a monopolist supplier was able to profit from charging prices significantly higher than the costs of an apple, for example, this would send a signal for other investors to start their own apple businesses, which in the long run, would drive prices down to marginal costs. The example is of course, an oversimplification and merely serves to provide a point of comparison. Unlike apples, demand for electricity is largely inelastic in the short run and investments require longer planning horizons and significant capital.[29]

25 EPIRA, Section 25
26 EPIRA, Sections 38-44
27 Adm. Order No. 38 (2002)
28 See J. García, J. Reitzes, International Perspectives on Electricity Market Monitoring and Market Power Mitigation, 6, Issue 3 REVIEW OF NETWORK ECONOMICS 375-376 (2007), quoted for reference below:
"(1) Suppliers in electricity markets face high sunk costs with lumpy, irreversible and long-lived investments. These characteristics limit quite substantially the entry of new players in the market in reaction to relatively short-term price increases.
(2) Network limitations of transmission systems impede the movement of electric power across geographic areas when transmission lines are congested. Transmission constraints can temporarily isolate geographic regions, allowing local generators to exercise market power by withholding capacity and artificially boosting prices.
(3) Short-term demand for electricity is very inelastic, largely because of the currently limited exposure of consumers to real-time prices under the prevalent fixed-priced service offerings, as well as the limited use of technology to monitor the real-time energy use of residential electricity customers.
(4) Electricity typically cannot be stored. Since system reliability requires that supply and demand has to be balanced instantaneously at every instant in time and at every location in the transmission network, and since intertemporal demand substitutability by consumers is limited, the inability to store electricity (except in hydro electricity systems and through deferred maintenance) implies that intertemporal supply substitutability cannot constrain attempts to exercise market power over relatively short time periods (for example, a few hours of a given day).
(5) The supply of electricity is fairly inelastic in the short-run, and the supply curve often increases substantially when output is close to full capacity. Moreover, electricity "supply curves" (based on the marginal cost of production) are often like "step" functions, where each step change represents a movement to a different fuel source (for example, from nuclear, to coal, to natural gas and to fuel oil) or a change in technology. This implies that, under certain demand conditions, the withholding of small amounts of electricity output may produce a large impact on energy prices since the market-clearing price moves to a higher step in the supply curve.
(6) In wholesale electricity markets (mainly those organized as auctions), sellers and buyers meet regularly, typically every hour. Repeated multimarket contact in electricity markets may enhance firms' abilities to tacitly collude and consequently achieve higher prices and lower quantities.
(7) Some argue that electricity markets are characterized by "boom-bust" investment cycles due to the high sunk costs involved in building generation plants. According this view, boom periods in power generation con struction are followed by periods of insufficient generation investment. When generation demand grows suf ficiently, this leads to episodes of high prices induced by the presence of limited excess generation capacity. "(citations omitted)
29 Id.

Therefore, having laid down the framework for a competitive electricity market, the EPIRA would go further and create structural safeguards against anti-competitive behavior and abuse of market power:

i. it prohibited any generation company or distribution utility from having any interest in the independent system operator,[30] thus removing any incentive for discriminatory treatment in the access and operation of the transmission backbone;
ii. it limited the market share of a generating company to thirty percent (30%) of the installed capacity of any single grid and twenty-five percent (25%) of the installed capacity in the national grid;[31] and
iii. it prohibited distribution utilities from sourcing more than fifty percent (50%) of its demand from supply contracts with related firms[32] to foster competition.In addition to these structural safeguards, the EPIRA likewise created a prohibition on market power abuse and anti-competitive behavior[33] and created an independent regulator, the ERC, tasked to *"monitor and penalize any market power abuse or anti-competitive behavior by any participant" .*[34]

The EPIRA Implementing Rules and Regulations (IRR) further specified that anti-competitive behavior and market power abuse would include the following:

i. fixing prices of products or services;
ii. fixing output of products or services;
iii. customer, product, service or territorial divisions;
iv. tying arrangements;
v. physical or economic withholding;
vi. discriminatory provision of regulated distribution or transmission services;
vii. misrepresentation or false advertising of a distribution utility; and
viii. use of cross subsidy of a distribution utility in relation to its competitive services.[35]

The list shows that the examples of anti-competitive behavior may include (i) collusive behavior, such as price fixing, tying arrangements or territorial divisions, (ii) unilateral actions such as discriminatory treatment, physical and economic withholding, and cross subsidy, and (ii) fraud based behavior such as misrepresentation or false advertising.

Under the EPIRA, anti-competitive behavior and abuse of market power is an administrative as well as a criminal offense,[36] hence it is enforceable by both the criminal justice system and administrative process. The quasi-judicial agency tasked with enforcing the administrative process is the ERC[37] and administrative sanctions imposed by the ERC are without prejudice to the filing of criminal action, if warranted.[38] Aside from the imposition of fines and penalties, enforcement actions which can be imposed by the ERC include imposition of price controls, issuance of injunctions, divestiture or disgorgement of excess profits.[39]

30 EPIRA, Section 45(2)
31 EPIRA, Section 45(4)(a)
32 EPIRA, Section 45(4)(b)
33 EPIRA, Section 45(1)
34 EPIRA, Section 45(8)
35 EPIRA IRR, Rule 11, Section 8
36 EPIRA, Section 45
37 EPIRA, Sections 43(k) and 45
38 EPIRA, Section 46
39 EPIRA, Section 45(8)

HIGH PRICES AND PHYSICAL AND ECONOMIC WITHHOLDING

High prices per se are not an indication of lack of competition, or that there is abuse of market power or anti-competitive behavior. In fact, high prices can be consistent with highly competitive markets in scarce supply conditions[40] and enable generators to recover fixed costs.

That being said however, the EPIRA IRR guards against exploitative or excessive pricing with respect to trading in the WESM, by prohibiting physical and economic withholding- methods which are common for exercising horizontal market power:

> *"Withholding of production is the most common method of exercising market power in a wholesale electricity market. Production may be withheld economically, which is referred to as economic withholding, by pricing it significantly in excess of marginal cost. Or it can be physically withheld, which is referred to as physical withholding, by not offering it at all. All else being equal, however, and assuming no collusion, withholding is profitable only if the supplier has market power, and only then does it become a concern."*[41]

Otherwise stated, the exercise of market power through physical or economic withholding is the ability of the monopolist to affect price outcomes through either reducing its output or increasing the prices of the output.[42] In the WESM, the reduction of output may be manifested through non-submission of offers, false declaration of outages or under-declaring the technical capability of a plant.

The EPIRA IRR states the prohibition on physical and economic withholding as follows:

> *"Physical or Economic Withholding: Electric Power Industry Participants shall not use physical operating practices or bidding strategies that limit the market participation of a generation unit under conditions that will result in significant increases in market prices".*[43]

Based on the foregoing, the EPIRA IRR clearly prohibits unilateral actions by suppliers that would have an impact on significantly increasing the market prices, and classifies such as market power abuse. This prohibition shields the consumers from excessive or exploitative pricing that may result from thin supply margins due to inadequate supply.

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40 P. Twomey, R. Green, K. Neuhoff, D. Newberry, A Review of the Monitoring of Market Power: The Possible Roles of Transmission System Operators in Monitoring Market Power Issues in Congested Transmission Systems, XI. No. 2, 8 THE JOURNAL OF ENERGY LITERATURE (2005)

41 P. Adib, D. Hurlbut, Power and Market Monitoring Market in COMPETITIVE ELECTRICITY MARKETS, DESIGN IMPLEMENTATION AND PERFORMANCE, 275 (2008)

42 S. Stoft, op. cit. note 1 at 322

43 EPIRA IRR, Rule 11, Section 8(e)

THE COMPETITION BILLS

BACKGROUND

At current there are two pending bills seeking to create a general competition policy for the Philippines. On 15 December 2014, the Senate approved on the third reading Senate Bill No. 2282 captioned, "An Act Promoting Fair Competition to Protect Consumer welfare, Advance Domestic and International Trade and Sustained Economic Development by, among others, Regulating Monopolies, Anti-Competitive Agreements, Abuse of Dominant Position, and Anti-Competitive Mergers, Establishing the Fair Competition Commission and Appropriating Funds Therefor, and for other Purposes", otherwise known as the "Fair Competition Act of 2015"[44]. The bill was transmitted to the House of Representatives on 17 December 2014.[45]

On the other hand, the House of Representatives have their own version, House Bill No. 05286 captioned, "An Act Promoting a National Competition Policy for the Philippines, Prohibiting Anti-Competitive Agreement or Conduct, Abuse of Dominant Position, Anti-Competitive Mergers and Acquisitions, and other Unfair Trade or Business Practices, Establishing the Philippine Competition Commission and Appropriating Funds".[46]

Both bills were filed in substitution of numerous earlier versions. The Philippine Institute for Developmental Studies (PIDS) reports that there were various attempts to pass competition laws as far back as the 1980s.[47] It appears however, that one of the drivers for pushing the bill of late, is the Association of Southeast Asian Nations (ASEAN) Economic Community Blueprint for 2015 where the Philippines undertook to establish a competition policy by 2015.[48]

While both bills may vary in specific details, they generally seek to prohibit anti-competitive agreements or conduct, abuse of dominant position and other unfair trade or business practices across all industries, including the electricity sector. Both bills likewise seek to regulate mergers and acquisitions and create a single commission to enforce the law. In many aspects, both bills are similar in formulation with the Sherman Act and Clayton Act of the United States, especially in defining the offense abuse of dominance, as limited to exclusionary behavior, and not including excessive pricing.

FEATURES

The main features of the bills are summarized, as follows:

Creation of a Competition Commission

Both the House and Senate version create an independent body to enforce the law in relation to mergers and acquisitions, anti-competitive agreements, abuse or market dominance and other unfair trade or business practices. They vary however, as regards the treatment of sectoral regulators. In the Senate version, the bill provides that the powers shall be cumulative with the sectoral regulator.[49] The House version however, states that the

44 S. No. 2282 16th Congress 2nd Session (2014) hereinafter referred to as "S.B. 2282"
45 www.Senate.gov.ph/lis/bill_res.aspx?congress=16&q=SBN-2282 ,last accessed on 9 February 2015
46 H. No. 5286, H. Rpt. 518 (2014) hereinafter referred to as H.B. 5286
47 R. Aldaba, The Impact of Market Reforms on Competition, Structure and Performance of the Philippine Economy , Discussion Paper Series No. 2005-24, Philippine Institute for Developmental Studies 25 (October 2005)
48 ASEAN Economic Community Blueprint, p. 18; See also the Sponsorship speech of Senator Aquino Senate Journal, 16th Congress, 2nd Regular Session (30 July 2014) p. 44-47,
49 Section 2, Chapter VII, S. B . No. 2282

authority of the commission shall be original and primary over all competition related issues to the exclusion of the sectoral regulator.[50]

Mergers and Acquisitions

Both bills state that the Competition Commission shall define when entities are required to notify the said commission of any merger or acquisition. Entities who are covered by the compulsory notification may not implement the merger or acquisition except after the lapse of thirty (30) days from notification. If the Commission requests for additional information however, the period shall be extended for another thirty (30) days. The Commission may disallow any such merger or acquisition if it deems that the agreements will prevent or substantially lessen competition.

Anti-Competitive Agreements

The draft bills prohibit any agreement which have the effect of substantially preventing or lessening competition that:

i. directly or indirectly fix, control or maintain prices;
ii. set, limit or control production, relevant markets, technical development or investment to the prejudice of consumers;
iii. divide or share the relevant market, whether by volume of sales or purchases, territory, type of goods or services, buyers or sellers or any other means;
iv. apply dissimilar conditions to equivalent transactions with other parties, thereby placing them at a competitive disadvantage;
v. fixing prices at an auction or in any form of bidding; and
vi. other similar conduct to the foregoing.[51]

As the bill defines the offense as an agreement, this will not cover unilateral acts by one entity. These acts are covered under abuse of dominant position.

Abuse of Dominant Position

The draft Senate bill defines the offense abuse of dominant position, as entities with a dominant position engaging in conduct “that would unreasonably and substantially prevent or restrict competition”, listing the following as examples:

i. selling goods or services below cost with the intent of driving competition out;
ii. imposing barriers to entry;
iii. subjecting a transaction subject to acceptance by the other parties of other obligations which have no connection with the transaction;
iv. setting pries or other terms or conditions that discriminate unreasonably between customers or sellers of the same goods or services, where the effect may be to lessen competition substantially (with exemptions);
v. restrictions or conditions of contracts with an object of limiting competition;
vi. making the supply of a particular goods or services dependent upon the purchase of other goods or services from the supplier which have no direct connection with the main goods or services to be supplied; and
vii. analogous agreements.[52]

50 Section 28 Chapter VI, H.B. 5286
51 Section 1, Chapter III, S.B. No. 2282
52 Section 2, Chapter III, S.B. No. 2282

The House version defines the offense similarly, but does not include (iii) and (vii).

Based on the text, it is clear that the law does not seek to penalize those who hold market power, but those with market power who engage in exclusionary conduct against its competitors, following the principle of *ejusdem generis*. This is further supported by the legislative deliberations, as explained by Senator Angara:

> *"He said that a large company with a large market share brought about by good business practice, such as offering a good price and quality products, would not be adversely affected by the proposed law.* ***He said that it is only when companies use their largeness and dominant position to edge out other players and make it difficult for new ones to enter the market that they are penalized****."*[53] *(emphasis supplied)*

Otherwise stated, under abuse of dominant position, a dominant corporation shall be allowed to set prices and maximize profits, provided it does not engage in exclusionary behavior. As explained by Justice Scalia, in explaining section 2 of the Sherman Act:

> *"The complaint alleges that Verizon denied interconnection services to rivals in order to limit entry. If that allegation states an antitrust claim at all, it does so under §2 of the Sherman Act, 15.U.S.C. §2, which declares that a firm shall not "monopolize" or "attempt to monopolize". Ibid. It is settled law that this offense requires, in addition to the possession of monopoly power in the relevant market, "the willful acquisition or maintenance of that power as distinguished from growth or development as a consequence of a superior product, business acumen, or historic accident." United States v. Grinnell Corp., 384 U.S. 563, 570-571 (1966). The mere possession of monopoly power, and the concomitant charging of monopoly prices, is not only not unlawful; it is an important element of the free-market system.*
>
> ***The opportunity to charge monopoly prices-at least for a short period- is what attracts "business acumen" in the first place; it induces risk taking that produces innovation and economic growth****. To safeguard this incentive to innovate, the possession of monopoly power will not be found unlawful unless it is accompanied by an element of anticompetitive conduct."*[54] *(emphasis supplied)*

Clearly, section 2 of the Sherman Act does not cover exploitative prices, as it "does not prohibit dominant firms from charging whatever price the market can bear.[55] Companies with monopoly power do not violate the Sherman Act unless that power is maintained or extended through some exclusionary Act."[56]

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53 Senate Journal, 16th Cong. 2nd Regular Session (20 August 2014) p. 172.
54 Verizon Communications Inc. v. Law Offices of Curtis V. Trinko LLP 540 U.S. 398 (2004)
55 S. Vaheesan, Market Power in Power Markets: The Filed-Rate Doctrine and Competition in Electricity, 46 Issue 3 UNIVERSITY OF MICHIGAN JOURNAL OF LAW REFORM (2013) citing IIIA Phillip E. Areeda & Herbert Hvenkamp, ANTITRUST LAW § 720a (3d ed. 2008)
56 Id.

Other Unfair Trade or Business Practices

The House version also includes a prohibition on fraud based activities which could lessen competition, as follows:

i. distribution of false or misleading information;
ii. unauthorized use or dissemination of confidential scientific or technical production,
business or trade information;
iii. making false or unsubstantiated representations about the characteristics of the product or service;
iv. making false claims relating to the price of the product or service;
v. failure to disclose the nature and extent of product or service guarantees;
vi. failure to disclose matters relevant to franchises and other business opportunities offered to consumers;
vii. misrepresentations as to a company's size, age and governmental or professional affiliation.[57]

DISCUSSION

As shown above, the Competition bills and the EPIRA overlap as regards anti-competitive behavior and abuse of dominant position as well as market share control. While the Senate version does not have an express repeal of section 45 of the EPIRA, it provides for a general statement that in case of conflict with provisions of existing competition laws and regulations, the provisions of the draft bill shall prevail. On the other hand, the House version provides an express repeal of section 45.

While an express repeal has an obvious impact on the WESM, a general repeal nonetheless, has a substantial effect on the EPIRA among others, on physical and economic withholding, in the absence of a saving clause.

REPEAL OF SECTION 45 OF THE EPIRA

The House version of the Competition bill contains an express repeal of section 45 of the EPIRA, which to recap, provides the following:

i. prohibition of any generation company or distribution utility from having any interest in the independent system operator;[58]
ii. limit of the market share of a generating company to thirty percent (30%) of the installed capacity of any single grid and twenty-five percent (25%) of the installed capacity in the national grid;[59] and
iii. prohibition on distribution utilities from sourcing more than fifty percent (50%) of its demand from supply contracts with related firms;[60] and
iv. prohibition on market power abuse or anti-competitive behavior.[61]

57 Section 7, Chapter II, H.B. 5286
58 EPIRA, Section 45(2)
59 EPIRA, Section 45(4)(a)
60 EPIRA, Section 45(4)(b)
61 EPIRA, Section 45(1)

The obvious effect of the repeal is the removal of the structural safeguards in the EPIRA and supplant them with market share control and general policy on market abuse and anti-competitive behavior. This begs the question whether a general competition policy alone when applied to electricity markets, is sufficient to protect the consuming public. It is respectfully submitted that it is not enough.

For one, the creation of an independent system operator is a key feature of successful electricity markets,[62] and for good reason. It removes the incentive for discriminatory or abusive behavior by removing conflict of interest. In places where an independent transmission operator was not mandated, the trend is towards creating policy to achieve independence, as underscored in the 2007 DG Competition Report on Energy Sector Inquiry of the European Commission, to wit:

> *"(475) A company active in electricity generation and/or supply that owns at the same time transmission or distribution network assets has, however, an incentive to use its monopoly position as network owner to prevent or limit competition in other areas of the value chain. This can happen in many ways such as: raising rivals' costs, price squeezes, withholding essential information and by providing the information only to affiliated companies. All of these practices distort a level playing field and render market entry more difficult. This in turn can reinforce the market power of incumbent generators/ suppliers. With the same token the market power of incumbent operators can be prolonged through the failure to invest in network expansion.*
> *(476) It is to limit the risk of such behaviour from occurring that the Second Electricity Directive contains unbundling rules for transmission and distribution networks. The transmission system operator ('TSO') must be independent at least in terms of its legal form, organisation, and decision making from other activities not relating to transmission. For distribution system operators ('DSO') the rules are similar. However, Member States are not obliged to implement fully the unbundling rules until 1 July 2007. They can also decide not to impose certain unbundling obligations on distribution companies that have less than 100.000 customers."*

Second, lifting the market share limitations in the EPIRA, albeit subject to regulation with respect to mergers and acquisitions, can only be detrimental to the electricity market, unless such provision were interpreted as decreasing the 25% and 30% requirement. It should be pointed out that on the basis of registered capacity alone, the market computed Herfindahl-Hirschman index was found to be moderately concentrated as of December 2014.[63]

Moreover, where supply is tight, such as during the November and December 2013 billing months in the WESM due to the scheduled Malampaya maintenance, nearly all participants were pivotal suppliers,[64] i.e., suppliers which were necessary to serve demand, therefore providing opportunity for nearly everyone to exercise market power.

Third, the limit of distribution utilities from acquiring supply from affiliates attempts to limit opportunities for sweetheart deals and promotes competition as regards supply, without need for ex post inquiry on reasonableness of contracts.

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62 See Table 1

63 Monthly Monitoring Indices- December 2014, www.wesm.ph/inner.PHP/downloads/monthly_market_monitoring_indices last accessed on 17 February 2015

64 Monthly Market Assessment Report for the Billing Period 26 November 2013 to 25 December 2013 p. 12, http://www.wesm.ph/inner.PHP/downloads/monthly_market_assessment_reports last accessed on 3 March 2015

Finally, as regards supplanting the definitions of anti-competitive behavior and market power abuse of the EPIRA with the Competition bill's definition of anti-competitive agreements, abuse of dominance and other unfair trade practices, it would seem that for the most part, it covers most of the concepts in the EPIRA, except however, for physical and economic withholding.

In the electricity market, power generators may refuse to offer to the market their available capacity (physical withholding) or bid such capacity at an excessive price (economic withholding) during periods of tight industry supply resulting in very high prices for the public since the demand for electricity is inelastic in the short term. This is prohibited under the EPIRA but does not fall under abuse of dominant position under the draft bills because they do not necessarily have to collude with other suppliers or engage in exclusionary conduct. The high price spikes may cause irreparable harm to certain industries resulting in significant damage to the economy and potentially endangering the whole political system since the price of electricity can be a very emotional issue. High price spikes in many commodities do not last long because of the interplay of market forces in a competitive market where high prices would dampen demand and trigger higher investments in producing more of the commodity thus stabilizing prices. This is not true in the electricity market which is considered a vital service while capacity takes a long time to build and demand is unable to adequately respond.

AMBIGUITY CAUSED BY THE GENERAL REPEAL

Unlike the House version, the Senate version does not provide for an express repeal of Section 45 of the EPIRA, but provides instead for a general repeal stating that in case of conflict with provisions of existing competition laws and regulations, the provisions of the draft bill shall prevail. What are the implications of this repeal?

The draft bill is meant to be the general competition statute, covering all areas of trade, industry and commerce with some exceptions.[65] As a rule general statutes do not repeal special statutes.[66] In the absence of the general repeal, the EPIRA would simply be carved out as an exemption to the general law. Because of the general repeal however, while the EPIRA would still be construed as an exception by virtue of being a special law, in the event of conflict between the latter general law and the special law, it is presumed that the legislative intent is to repeal or amend the special law.[67]

Absent a saving clause, this causes some ambiguity with respect to the structural safeguards under section 45 of the EPIRA, namely:

i. cross-ownership prohibition in relation to the transmission operator;
ii. installed capacity limits; and
iii. limits on bilateral supply contracts with affiliates.

The courts may take the approach that these are examples of market power, but not market power abuse. Since this is not prohibited under the Competition bill, the courts may construe the same as inconsistent with the competition bill and therefore repealed. On the other hand, courts may also construe this as continuing to apply, limiting the interpretation of these provisions of section 45 as merely regulatory in nature, not necessarily in conflict with the competition statute. The nature of the repeal creates a level of ambiguity, and space for judicial construction of law.

65 Section 3, Chapter I, S.B. No. 2282
66 R. AGPALO, STATUTORY CONSTRUCTION 419 (4th ed., 1998), citations omitted
67 Id., at 415, citations omitted

On the other hand, the examples of anti-competitive behavior under the EPIRA IRR[68] are not inconsistent with the draft senate bill, except with regard to (i) physical and economic withholding, (ii) cross subsidy and (iii) misrepresentation or false advertising of distribution utilities.

As discussed above, physical and economic withholding are forms of market power abuse which are not defined in the EPIRA, but are provided in the IRR. They are inconsistent with the concept of abuse of market dominance in the draft bill since the latter requires exclusionary conduct in the exercise of market power. Due to this, economic and physical withholding may become unenforceable, being directly inconsistent with the draft bill by virtue of the general repealing clause. This allows for the unilateral exercise of market power, which may cause large wealth transfers to the suppliers, to the detriment of the consuming public.

CONCLUSION

The articulated policy for passing a comprehensive competition policy was to promote economic efficiency towards attaining "a more equitable distribution of opportunities, income and wealth; a sustained increase in the amount of goods and services produced by the nation for the benefit of the people; and an expanding productivity as the key to raising the quality of life for all, especially the underprivileged..."[69] , echoing section 1, Article XII of the Constitution. The bills likewise derive their basis from section 19, Article XII of the Constitution which states:

> *Sec. 19. The State shall regulate or prohibit monopolies when the public interest so requires. No combinations of restraint of trade or unfair competition shall be the allowed.*

The Supreme Court had occasion to discuss the interplay of both sections, explaining the limits of free enterprise and the role of the state as follows:

> *"Beyond doubt, the Constitution committed us to the free enterprise system but it is a system impressed with its own distinctness. Thus, while the Constitution embraced free enterprise as an economic creed, it did not prohibit per se the operation of monopolies which can, however, be regulated in the public interest. Thus too, our free enterprise system is not based on a market of pure and unadulterated competition where the State pursues a strict hands-off policy and follows the let-the-devil devour the hindmost rule. Combinations in restraint of trade and unfair competitions are absolutely proscribed and the proscription is directed both against the State as well as the private sector. This distinct free enterprise system is dictated by the need to achieve the goals of our national economy as defined by section 1, Article XII of the Constitution which are: more equitable distribution of opportunities, income and wealth; a sustained increase in the amount of goods and services produced by the nation for the benefit of the people; and an expanding productivity as the key to raising the quality of life for all, especially the underprivileged. It also calls for the State to protect Filipino enterprises against unfair competition and trade practices." [70](citations omitted)*

68 Rule 11, Section 8
69 Section 2, Chapter VII, S. B. 2282
70 Francisco S. Tatad v. Secretary of the Department of Energy et. al., G.R. No. 124360, November 5, 1997

The heart of the matter therefore, is public welfare premised on an economic principle which now, finds basis in a legal norm. Do these bills serve this purpose?

A review of both bills proposed separately by the Senate and the House of Representatives, show that the prohibition on abuse of market dominance centers on exclusionary behavior, and excludes excessive pricing. This is of consequence when interpreted together with the EPIRA because while the EPIRA does not itself define abuse of market dominance, or market power abuse (as referred to in the EPIRA), the implementing rules and regulations specifically include physical and economic withholding as examples, which covers excessive pricing.

If physical and economic withholding is removed as an offense by virtue of repeal (whether implied or express), the government will be bereft of enforcement powers such as disgorgement of profits, injunctions and price controls,[71] to ensure the protection of the consuming public for any person that exploits opportunities to set prices higher than the consumers are willing to pay. While it cannot be disputed that adoption of a general competition policy shall be beneficial for the country, careful consideration should be given in relation to the electric power industry in view of its effect on the provisions of the EPIRA which were meant to protect the consuming public. The general competition policy should be viewed as something cumulative to the EPIRA instead of something in substitution of, given the nature of the electric power industry. The gains from passing a general competition statute should not be offset by what is lost through repeal by implication.

71 EPIRA, Section 45(8)



3

GENERATION COST REDUCTION THROUGH OPTIMAL ALLOCATION OF ENERGY TRANSACTIONS BY BILATERAL QUANTITY ADJUSTMENTS *with* CORRESPONDING PENALTIES

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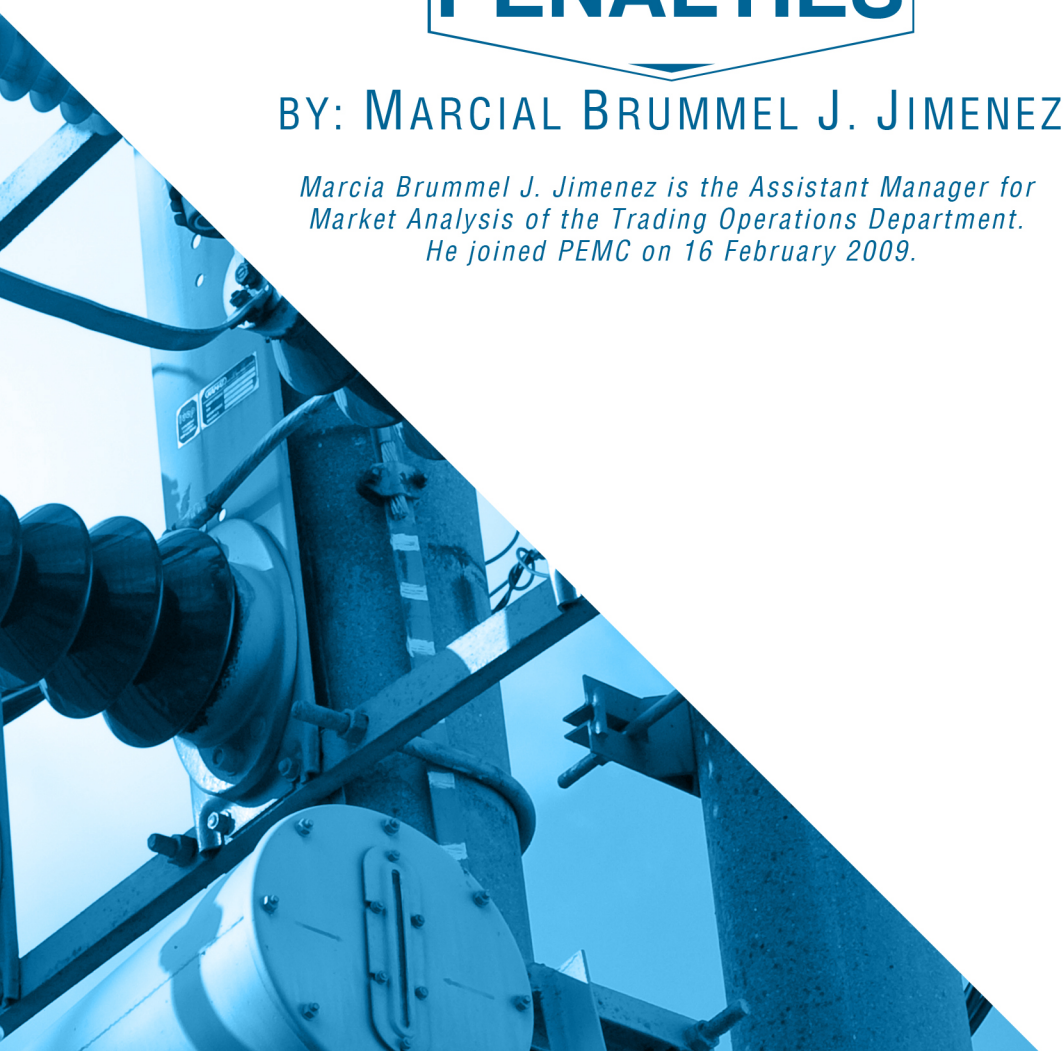

ABSTRACT

An electricity market is established to create a fair, transparent and reliable trading environment and encourage competition that will lead to reasonable cost. In this set-up, it is very important that the distribution companies allocate their purchases of energy in the spot market and in the bilateral contract in the most economic manner.

This study developed a methodology for re-scheduling the economic purchases of energy in the spot market and through bilateral contract adjustments with corresponding penalties. The methodology minimizes the total monthly energy cost by optimally allocating the energy purchases between spot market and bilateral contracts. Likewise, it considers the effect these changes have on the generation companies' contracted sales. The corresponding penalty cost is based on the equilibrium point wherein the distribution company's savings matches the increase in the generation companies' sales. The methodology is applied to the settlement processes as defined in the Philippine Wholesale Electricity Spot Market (WESM) Rules and Price Determination Methodology (PDM), in which bilateral contract quantities are used as decision variables in the linear programming. The new schedules of bilateral contract quantities, which are beneficial to both generating and distribution companies, yielded cheaper energy purchases without breaching the contracts. This will eventually lead to lower generation costs for the consumers.

Key Terms: bilateral contract, electricity market, quantity declaration adjustment, flexible forward contracts, contract delivery scheduling

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INTRODUCTION

Electricity cost in the Philippines increased in the summer of 2010 as a result of the tight power supply and demand condition, which were reflected on the electric bills of end-users. This was basically due to the shutdown of the Malampaya platform and pipelines, which forced Distribution Companies (DisCos) to contract Independent Power Producers (IPPs) that utilized more expensive alternative fuel resulting in higher prices of energy procured from natural gas-fired plants [8]*. The El Niño Phenomenon also sweeped across the nation, resulting in limited supply from hydroelectric power plants, which are cheaper sources of electricity. Studies have shown that tight supply/demand conditions and the weak state of the transmission system in a full and unregulated spot market may lead to severe market power problems. However, regulation of the market, demand response programs and adequate bilateral contracting levels may avert the problems foreseen in the market [2].

The sharp rise in electricity cost was attributed to the increase in the cost of generation. This generation cost consists of the bilateral contracts transactions and spot market transactions. The Philippine Wholesale Electricity Spot Market (WESM) is the venue for trading electricity as a commodity in the spot market, while the bilateral contracts transactions are settled outside of the WESM.

As stated in Section 23 of the Electric Power Industry Reform Act(EPIRA), “a distribution utility shall have the obligation to supply electricity in the least cost manner to its captive market, subject to the collection of retail rate duly approved by the ERC.” This responsibility calls for proper planning in the procurement of power in “the least cost manner,” which is the implementation of measures to address demand requirements in an ideal or an emergency situation [1]. Thus, allocation of bilateral contracts and spot market transactions is a major task of the distribution utility to effectively achieve the least cost of electricity. However, as provided in the WESM Rules 3.13.1.1, it is the generation company that will declare the Bilateral Contract Quantity (BCQ) for every interval (hour) provided that it has the evidence that the counterparty or the DisCo agrees on the traded quantity. This means that the DisCo may or may not agree with the BCQ declared by the generation company, thus, optimal allocation of the BCQ and spot market quantity can be obtained from the DisCo’s perspective.

This study aims to obtain the least cost of energy purchases of the distribution company by reducing generation cost through optimal allocation of its spot market and bilateral contract transactions through quantity adjustments with corresponding penalties.
The study specifically aims the following:

1. To gather and process the hourly data consisting of prices and schedules for the spot market and bilateral contracts prices and transactions of a certain distribution utility.
2. To generate the optimal allocation of spot market bilateral contract quantity using the optimization model defined in the reference paper for single spot market price settlement system.
3. To develop an optimization model for a two spot market price settlement system considering line rental, as define in the settlement processes of the Philippine WESM.
4. To determine the suitable penalty cost based on the equilibrium point wherein the distribution company’s savings matches the increase in the generation companies’ sales.

* Note: Please see References section.

This study is limited to the optimal allocation of the spot market and bilateral contract transactions on a particular billing month between one Distribution Company and the Generation Companies it has bilateral contracts with. Other financial factors such as government taxes, interest rates, depreciation and other financial derivatives will not be examined in this study. The study is also limited by the confidentiality of the actual metered energy quantities, bilateral contract quantities, terms and condition of the bilateral contract and other data treated as confidential in the Philippine WESM. Furthermore, calculation of the payment due to the bilateral contracts may not be accurately captured since the study calculated this based only on the published PHP/MWh rates in the ERC Website multiplied by the contracted quantities.

The study was applied to a gross pool, Locational Marginal Price (LMP)-based electricity market, or specifically, this study was applied to the pricing mechanism adopted by the Philippine WESM for the settlement of the spot market transactions. However, the flow back mechanism associated with the Net Settlement Surplus (NSS) was not included in the study. Also, since the BCQs are permitted to be declared a day after (D+1) the conclusion of the trading interval, the spot market prices used herein were considered final.

OVERVIEW OF BILATERAL CONTRACTS AND WESM TRANSACTIONS

ENERGY TRANSACTIONS

Normally,the trading of electricity in wholesale markets has two main forms – spot trade with an hourly coordination of demand and supply and a medium and long-term forward trade based on bilateral forward contracts. Bilateral contracts for physical delivery are widely applied in competitive electricity markets. In many countries, bilateral trade covers the main portion of electricity delivery[1].

From a risk management point-of-view, participating in the spot market is a risky trading approach because the energy spot price fluctuates over time and the Generation Companies (GenCos) and Distribution Company (DisCo) cannot confirm the revenue from the spot market when they make their trading decisions. By contrast, the energy price of bilateral contracts is determined a *priori*. Normally, when there is no congestion in the network, bilateral contract can be considered as a risk-free trading approach [3]. Thus, bilateral contracts are commonly used to hedge or mitigate a marketprice risk as they stabilize prices and reduce the possibility of market power abuse in the spot market.The spot market and bilateral contract market influence each other and interact with each other [1].

In the Philippine set-up, the spot market price and quantity consists of two components – the ex-ante and ex-post. The ex-ante market run determines the market price before that trading interval commences, while the ex-post market run determines the market price after that trading interval concludes.The prices and schedules of the ex-ante and ex-post dispatch processes are determined by the Market Dispatch Optimization Model (MDOM) of the Philippine WESM, while bilateral contract quantities may be declared a day after the trading interval has already concluded. Because of this set-up, the prices and quantities are already known prior to the declaration of BCQ. This may be used to the advantage of the GenCo or DisCo.

BILATERAL CONTRACT NEGOTIATION IN ELECTRICITY MARKETS

In gross pool electricity markets, participants may engage in bilateral contracts several months in advance of its delivery. In addition, GenCos may sell and DisCos may buy from the pool at the spot price through the day-ahead or balancing markets. Forward bilateral contracts have the advantage of price predictability as opposed to the uncertain spot price. However, the risk is that such a contract commits the partners to a price that may be disadvantageous compared to the spot price [9].

This bilateral contract is a commitment between a GenCo and DisCo for selling and buying electricity. A typical contract requires quantity, price and delivery date and time. From a microeconomic point-of-view, DisCo profits are defined as the difference between revenues from selling electricity and the cost to buy electricity for its native demand [8].

The paper, “Contract Price of a Bilateral Contract Using Risk Assessment,” by José D. Arias R., Diego F. Cardona B. and Harold Salazar I. [8] presented a methodology to find contract prices that maximize the profits of DisCos while keeping the risk below some confidential level. This paper considered a risk assessment methodology that establishes the contract price.

According to [8], the annual profit of DisCosis calculated as follows:

$$\pi_g = \sum_{h-1}^{n} \left[td(h) - p(h)\left(d(h) - p_g(h)\right) - p_c p_g(h) \right] \Delta$$

Eq. 1

Where
π_g is the profit
td(h) is the load revenue
d(h)s the demand at time t
p_g (h) is the contract quantity
p_c (h) is the contract price
p(h) is the spot price

The proposed risk assessment methodology is to find the contract price of a bilateral contract that took into account the DisCo’s profits, generator’s profits and risk assessment. The methodology requires a price range of possible contract prices. This range, also called the negotiation range, is defined based on historical information. This methodology assumed real time prices and generation dispatch assumed as random variables with certain probability distribution function, which is useful in determination of the contract price.

Another paper, “Negotiating Bilateral Contracts in Electricity Markets,” by Sameh El Khatib and Francisco D. Galiana [9], proposed a systematic negotiation scheme through which a generator and load can reach a mutually-beneficial and risk-tolerable forward bilateral contract, either physical or financial, or conclude that it is not in their mutual interest to enter into such an agreement. Under this approach, the generator and load respond rationally to a stream of bilateral bids/counter-bids and offers/counter-offers considering their respective benefits while accounting for the risks incurred by the prediction uncertainty in the pool spot price and other market parameters over the length of the contract. Each negotiating party can choose its own definition of risk, which can be influenced by regret, value-at-risk or dispersion from the mean [9].

In this paper [9], three approaches were used to assess the risk of a projected bilateral contract:

1. Based on the notion of regret, under which the negotiating partner is influenced by the probability that the profit will not be sufficiently close to the best possible ideal value – in other words, what it could have earned if the market parameters had been predicted exactly at the time of contract negotiation;
2. Based on the notion of value-at-risk, under which the negotiating partner is influenced by the minimum profit it can earn with a given probability; and
3. Based on the notion of dispersion of the profit, under which the negotiating partner is influenced by the probability that the profit will deviate excessively from its mean value.

The uncertain market parameters considered in [9] are the power plant efficiency and fuel cost coefficients, the load revenue factor and the spot prices and load demand levels at periodic time intervals, respectively.However, note that in the Philippine set-up, upon declaration of bilateral contract quantities, the spot prices and load demand levels are already known. Because of this, its optimization model on the ideal load profit is useful in the Philippine set-up since it is computed by adjusting its bilateral contract amount assuming that the uncertain market parameters are known at contract negotiation time. The objective funtion of [9] ideal load profit is shown below:

$$pr^d = \sum_{t-1}^{nc} [BD^t - \lambda^t (d^t - GD) - \pi GD] \Delta$$

Eq. 2

Where
pr^d is the profit
BD^t is the load revenue
d^t is the demand at time t
GD is the contract quantity
π is the contract price
λ^t is the spot price

The approach developed a model in which a generator and load can negotiate a bilateral contract described by its time of delivery, duration, amount and price. This is very flexible, allowing the negotiating parties to self-specify their risk/benefit measures, as well as the corresponding acceptable thresholds. But since declaration of bilateral contract quantity in the Philippine set-up is done after the interval has been concluded, inclusion of risk and benefit measures may not be applicable.

On the other hand, the paper on “Bilateral Negotiation of Energy Contracts from the Buyer Perspective” by J. C. Mateusand P. Cuervo [11] presented a decision support model considering the perspective of a buyer who needs evaluating a basic set of contractual conditions. The approach recognizes that a potential new contract under negotiation introduces two main risks:

1. Related to the insufficiency of load supply to end users; and
2. Related to the volatility of the short term spot prices used as a reference for defining the contractual price.

In this paper [11], a buyer portfolio optimization problem determines the best purchase strategy within a contractual period defining the required energy amounts in each interval of

the period in order to minimize the agent's payments. Considering the contractual price of a new contract and having a spot price forecast based on statistical records, the buyer has several alternatives to meet their own load consumption along the contractual period. Since the revenues coming from selling energy to end-users are normally supervised by the regulator through fixed rates and the spot market can be modeled as negative payments, the buyer optimization model is the minimization of payments instead of the maximization of profit.
The annual buyer payment in [11] is calculated as follows:

$$ABP = C^{BCC} - T^{Spot} - C^{Pen}$$

Eq. 3

Where
ABP is the DisCo's payment or total transaction cost
C^{BCC} is the total annual payment of contracts
T^{Spot} is the total annual payment for spot
C^{Pen} is the penalty paid by the DisCo in case of insufficiency of load supply

From (3), the paper in [11] derived its optimization model as a decision support tool designed for buyer agents during negotiation of bilateral energy contracts. The suggested model considers the characteristics of bilateral contractual conditions and the minimization of the buyer payments. Here, bilateral contracts involve uncertainties in prices and load, making it necessary to estimate the levels of risks involved. Since these variables are uncertain along the contractual period, a procedure involving a Monte Carlo simulation and payment minimization allows obtaining levels of risks. The risks involved during negotiation are the risk of not being able to fully supply end-users through bilateral contracts and the risk of unfavorable exposition in the short term market DisCos to the possible buyer participation for compensating the load.

Conversely, from the point-of-view of the GenCo in the paper, "Hydrothermal Bilateral Contract Negotiation with Energy and Financial Risks Analysis" by the same authors, J. C. Mateusand P. Cuervo [10], a methodology to facilitate the decision-making process of hydrothermal generation companies during the negotiation of bilateral contracts was presented. It considered the risk of deficit of energy availability introduced by a new contract under negotiation given the uncertainty in the concept of ensured energy of hydro units and required buyer modulation along the period of contracts due to load seasonal variation. This is analyzed in terms of the impact on the GenCo's risk to unfavorable prices given the uncertainty in spot prices.

Long-term bilateral contracts have a duration of several years, thus, the forecast of some variables like hydrologic conditions, availability of units, load and spot prices could be imprecise and complex. Because of this, the model presented in [10] focuses on the negotiation of long-term bilateral contracts processes considering a revision on the contractual terms on a yearly basis.

It defines annual generator profit as follows:

$$GAP = R^{CONT} - T^{Spot} - C^{Gen} - C^{BC} - C^{Pen}$$

Eq. 4

Where
GAP is the Generator profit
R^{CONT} is thetotal GenCorevenue from selling through bilateral contracts
T^{Spot} is the total GenCospot transactions
C^{Gen} is the cost of energy production
C^{BC} is the cost of purchase of bilateral contracts
C^{Pen} is the penalty paid by the GenCoin case of insufficiency of load supply

In both papers of Mateus and Cuervo, in the negotiation of new contracts, GenCos and DisCos are subject to attend the annual regulator energy requirements to avoid energy availability deficit. Financial penalties are imposed for not meeting the requirements. This model gives information about the risk of such deficit for a new contract under negotiation allowing both GenCo and DisCo to estimate the financial feasibility of the contract.

In another research paper entitled, “Optimal Bidding and Contracting Strategies in the Deregulated Electric Power Market: Part I” by D.J. Wu, Paul Kleindorfer and Jin E. Zhang [12], the long-term contracting and spot market transactions between one GenCo and one or more DisCos were considered. The basic model proposed allows the GenCo and DisCos to negotiate bilateral electric power contracts and then, on the day, to sell or buy in an associated spot market.This paper considers a deregulated electric power market in which there are GenCos, DisCos and a Transmission Company. The GenCo may either sign long-term contracts with the DisCo to provide a fixed quantity of output ex-post, or sell its output in the spot market. Similarly, DisCos may sign long-term contracts to cover their anticipated needs, or they may cover these needs through purchases in the spot market.

This paper [12] used the Quasi-Linear Form of DisCo’s Utility or its Willingness to Pay (WTP) at a certain price.

$$V(D,Q,P) = U(D) - sQ - gq(P_s, g, Q, D) - P_s X$$

Eq. 5

Where
$V(D,Q,P)$ is the DisCo’s profit
$U(D)$ is the DisCo’s willingness to pay
s is the reservation cost of the contracted capacity
Q is the reserved contract capacity
g is the cost of execution of the contract
$q(P_s,g,Q,D)$ is the actual contract quantity that has been committed
P_s is the spot market price
X is the energy purchased in the spot market

It can be noted that the first term is similar to the total revenue of the DisCo, the second and third terms refer to the bilateral contract transactions of the DisCo, and the last term for spot transactions.

Basically the four papers [1], [2], [3] and [5] are consistent in defining the DisCo’s profit or generation cost, while [4] has almost the same pattern for the GenCos’ profit. Generally, the DisCos’ generation cost model [1], [2], [3] and [5] can be written as follows:

$$DISCO_{GENCOST} = BCT + SMT + Pen$$

Eq. 6

Where
$DISCO_{GENCOS}$ is the DisCo's total cost of energy purchases
BCT is the DisCo's Bilateral Contract Transactions
SMT is the DisCo's Spot Market Transactions
Pen is the DisCo's penalty payments

Note that in equations (1)[8],(2) [9] and (5)[12] the DisCo's profit is considered in the model. This means that the DisCo's revenue is a function of some variables that is considered in the model. However, in (3) [11] and (4) [10], the DisCo's revenue was removed as it assumed that this is normally supervised by the regulator through fixed rates. In the Philippine set-up, since the generation cost is passed on by the DisCos to the consumers, equations (3) and (4) are more applicable.

Also, it can be noticed that equations (3) and (4) considered a penalty parameter in its model. However, this penalty is charged by the regulator to the DisCo or GenCo when the contract resulted in insufficiency of supply rather than changing the contract quantities. On the other hand, (5) does not explicitly charge penalties if the contract is not delivered. Rather, penalties might be derived through the interaction of the reservation and execution costs, which are part of the Bilateral Contract Transactions.

It is also worthwhile to note that all of the five papers considered uncertainties in the spot prices and demand levels upon declaration of the bilateral contract quantity, which is effective for negotiating long-term contracts. However, in terms of the Philippine set-up where the declaration of bilateral contract quantity is done after the interval has been concluded, inclusion of random variables and risk assessments may not be applicable because the prices and dispatch schedules are already known before declaring the contract quantity.

In the succeeding section, bilateral contract quantity adjustments are factored in in the optimization considering generation cost as the DisCo's model.

BILATERAL CONTRACT (BC) CORRECTION AND CANCELLATION [1]

Bilateral Contracts are commonly used to hedge or mitigate a market price risk. They stabilize prices and reduce the possibility of market power abuse in the spot market. Usually, the contract is between the GenCos and DisCo that sells electricity to the end consumers. Both parties forecast price levels in the spot market and electricity demand. The spot and bilateral contract markets influence each other and interact with each other to determine the effective cost of generation. The volumes and prices stipulated in bilateral contracts influence the trade volumes and prices in the spot market since contracted quantities are usually offered at very low prices in order to be scheduled. Thus, the spot market risks and price behavior have an impact on the contract arrangement strategy of the contract parties. Electricity received under bilateral contracts may be resold in the spot market and electricity bought in the spot market may be delivered to fulfill bilateral obligations. Bilateral contracts can be concluded for the period from several weeks to several years, depending on the agreement of both parties. Deliveries are scheduled by the contract parties up to the moment of contract conclusion using forecasted data. Potential bilateral contracting parties schedule the deliveries by time intervals during the contract period in an optimal way to get the highest profit and devise a strategy of their participation in the spot market. On the other hand, conclusion of bilateral contracts bears certain risks because of price and demand uncertainties in the competitive market. Each party estimates contract profit or financial loss expected in changing market conditions. Each contract party can make a decision on contract parameters correction or contract cancellation, if the expected profit is not acceptable. The other party has the right to accept or reject a proposed correction.

The contract corrections or cancellations are considered for hedging commercial losses. These contract corrections are initiated by either of the contract parties. Certainly, decision-making on contract correction has to take into account financial compensations for the other partner.

Arrangement of BC constitutes that the contract parties should set the following contract parameters:

- Contract duration from delivery start, T_1 to termination, T_N;
- Number N and duration of time intervals t within the contract period;
- Total electricity amount V to be delivered by the contract (contract volume), MWh;
- Electricity amount x^t to be delivered in time interval t, MWh. Amounts x^t, $t=T^1$, …, T_N form a delivery schedule. Contract correction means correction of the schedule x^t, $t=T_1,...,T_N$;
- Contract prices of electricity p^t, $t=T^1$, ...,T_N, delivered under BC, \$/MWh. The prices p^t, $t=T_1,...,T_N$ are related to the forecasts of spot prices and seasonal deviation of electricity prices.
- Fine on the supplier in the case of delivery reduction initiated by supplier, p^t_{int}, \$/MWh;
- Fine on the buyer in the case of delivery over-drawing, initiated by buyer, p^t_{ovd}, \$/MWh;
- Financial compensation ΔF to the other party in the case of pre-scheduled contract cancellation;
- Time Δt required to approve contract correction (time from the point when decision on correction have been made to the point of new delivery schedule start up). The time Δt is needed to inform the partner about proposed contract correction and for registration of contract correction by the System Operator.

The following additional parameters can be fixed at the stage of bilateral contract arrangement:

- List of time intervals when electricity delivery has not to be changed;
- Number of contract corrections allowed during the contract period;
- Maximal reduction or increase in contract delivery in time intervals if BC is not cancelled.

Stages of Bilateral Contract Corrections:

Stage 1.Updating of Forecast Demand

Starting from the first time interval, each BC party follows the delivery schedule originally stipulated in the BC. Each party keeps track of actual demand and price behavior and updates price and demand forecasts up to the end of the contract period. Actual prices and new forecasts may deviate significantly from those predicted before the contract conclusion. Both parties estimate their actual and expected profits (or losses), provided the original BC schedule x^t, $t=T_1$, …T_N is implemented strictly. If the estimation shows a significant reduction in the expected profit or losses, one of the BC parties goes to Stage 2.

Stage 2.Bilateral Contract Correction

The party-initiator of correction develops a new delivery schedule and estimates its possible profit or loss in the case of the contract correction. The profit is obtained taking into account the fine for changing its obligations. It makes a decision on the contract correction during interval T1- tH.The optimization model is as follows:

$$S_n = MaxE\left[\sum_{t=T_c}^{T_N}(P_d^t(X_{kN}^t + X_{sN}^t) + P_{sF}^{\sim t}(X_{ssN}^t - X_{sN}^t) - p^t x^t) - P_{ovd}^t(|x^t - X_{kN}^t - X_{sN}^t|)\right]$$

Eq. 7

Subject to

$$x^t - X_{kN}^t - X_{ssN}^t = 0 \qquad ,t = T_c, \dots, T_K$$

$$X_{kN}^t + X_{sN}^t = X_{dF}^t \qquad ,t = T_c, \dots, T_K$$

Eq. 8

$$X_{min}^t \le X_{kF}^t + X_{ssN}^t \le X_{max}^t \qquad ,t = T_K, \dots, T_N$$

Eq. 9

$$X_{kN}^t \ge 0\ , X_{sN}^t \ge 0\ , X_{ssN}^t \ge 0 \qquad ,t = T_c, \dots, T_N$$

Eq. 10

Where
S_n is the profit
$P_{sF}^{(\sim t)}$ is the updated forecast spot price
X_{dF}^t is the updated forecast spot quantity
P_d^t is the price at the consumer end
X^t is the total BCQ
X_{kN}^t is the BCQ delivered to the DisCo
X_{ssN}^t is the BCQ sold by the DisCo to the spot market
X_{sN}^t is the energy bought by the DisCo from the spot market
P_{ovd}^t is the fine on the buyer for over-withdrawing/reduction

Stage 3.Bilateral Contract Cancellation

The party-initiator of correction considers the possible cancellation of the BC during the interval and estimates the profit or loss in the case of contract cancellation. The profit is obtained taking into account the financial compensation for contract termination.

Stage 4.Comparison of Results

The party-initiator of correction chooses the best decision considering the analysis made at stages 1, 2 and 3. It proposes the BC correction or cancellation to another partner at time t_H.

Stage 5.Recommendation to Generation Company

The party-initiator of correction informs the other partner about its decision during period t and proposes a new delivery schedule. The partner estimates consequences of the proposed correction during interval and approves (or rejects) the new delivery schedule. If the contract correction is appropriate for the second party, the new delivery schedule should be approved by the System Operator. Both parties follow the original delivery schedule x^t, $t=T_1,\dots,$ TN during t, while the actual situation in the market may differ from that originally predicted. The new delivery schedule or contract cancellation starts with interval t_K.

Stage 6.GenCo Accepts or Rejects Recommendation

Electricity delivery under BC continues from according to the new delivery schedule. Both BC parties continue to analyze the levels of spot prices and update price and demand forecasts up to the end of the BC period. They continue to estimate expected profits (or losses) using improved forecasts. Decision on the next contract correction can be made by the same or the other contract party.

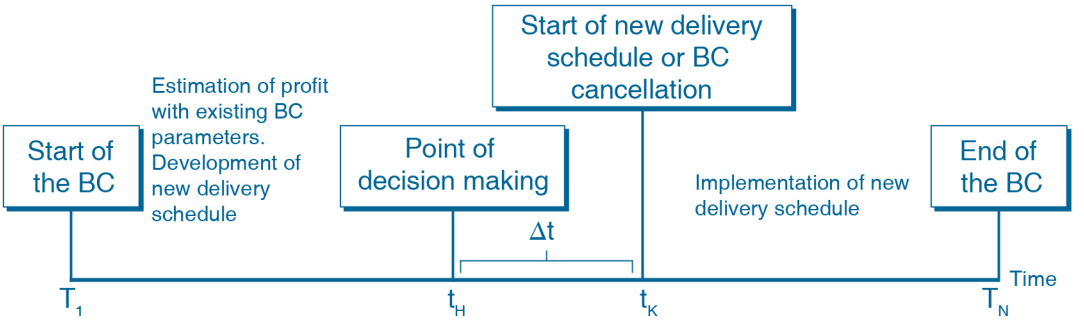

Figure 2.3-1 Stages of Bilateral Contract Correction and Cancellation [1]

MARKET DISPATCH OPTIMIZATION MODEL (MDOM)

As per WESM Rules Clause 3.6.1.1, the MDOM simultaneously determines schedules of energy and reserve for the trading interval, including the associated energy and reserve prices at all trading nodes in the power system.The objective of the MDOM is to maximize the value load schedules based on their bids while minimizing the generation costs and the cost of constraint violation.

In the optimization of pricing and scheduling, the MDOM considers the following constraints:

a. Constraints representing limits on generation offer, demand bid and when applicable, reserve quantities as specified by the Trading Participants;
b. Constraints representing the technical characteristics of reserve facility categories, including when applicable, reserve effectiveness factors initially set at one (1);
c. Energy balance equations for each node in the market network model ensuring that the net load forecast for the end of the trading interval at each market trading node as determined by the Market Operator is met;
d. Constraints representing limitations on the ramp rate from the plant status deemed to apply prior to the commencement of the trading interval;
e. Constraints defining power system reserve requirements as provided by the System Operator;
f. Network constraints, as implied by the market network model provided by the System Operator;
g. Loss and impedance characteristics of market network lines, as advised by the System Operator;
h. Constraints on the high-voltage, direct current (HVDC) link operations, as advised by the System Operator;
i. Power flow equations, as defined by a direct current (DC) approximation to an alternating current (AC) power flow within AC sub-systems, or equivalent mathematical representation;
j. Any overriding constraints imposed on the recommendation of the System Operator; and
k. Any additional constraints due to ancillary services or system security requirements.

The MDOM is applied in the ex-ante and ex-post market runs in the WESM. The only difference between the ex-ante and ex-post market runs are the inputs. Table2.4-1 below summarizes the difference in the inputs of ex-ante and ex-post market runs.

Parameters	Ex-Ante	Ex-Post
Load Forecast	Market Operator's forecast demand for the target hour	Based on the actual demand as monitored by the Supervisory Control and Data Acquisition (SCADA) system.
System Snapshot This includes the generator and customers MW loading and the connection status of the equipment (transmission lines and transformers).	54th minute of the previous hour For example, if the target hour is 1000H, the ex-ante market run shall commence at 0855H. Thus, the latest snapshot will be the 0854th snapshot,which shall be used for the initial values.	59th minute of the target hour For example, if the target hour is 1000H, the ex-post market run shall commence at 1000H. Thus, the latest snapshot will be the 0959th snapshot, which shall be used for the initial values.
Outage schedules and security limits	Latest data as of the 54th minute of the previous hour For example, if the target hour is 1000H, the ex-ante market run shall commence at 0855H.If the System Operator (SO) submits an outage schedule for 1000H at 0930H, it will not be considered.	Latest data as of the 59th minute of the target hour For example, if the target hour is 1000H, the ex-post market run shall commence at 1000H.If the SO submits an outage schedule for 1000H at 0930H, it will be considered as opposed to the ex-ante.
Must-Run Units(MRU)	The MRU is scheduled based on the security limit submitted by the SO.	The MRU is scheduled based on its actual loading at the top of the hour.

Table 2.4-1 Difference inthe Inputs of Ex-Ante and Ex-Post Market Runs

It can be noted that the ex-ante market run is based on the projected inputs, while the ex-post market run uses information that has already transpired. In terms of settlement, the ex-post functions as the price discovery for the market imbalances created by the difference between the forecasted and actual conditions.

Furthermore, in some instances, a combination of inputs does not allow the MDOM to produce a feasible solution. Under WESM Rules 3.6.2.1, to satisfy all constraints, Constraint Violation Coefficients (CVCs) are incorporated in the MDOM. With respect to the objective of the MDOM stated above, these CVCs are the basis for the cost of constraint violation. The CVCs are defined in the Constraint Violation Coefficient (CVC Manual) [20]. Table 2.4-2 shows the CVC values as approved in the CVC Manual.

Priority	CVC Name	Price (P/MW)	Definition	SO Action
10	Deficit Interruptible Load Reserve	100,000	Insufficient interruptible demand to meet reserve requirement	This is not a problem if the dispatchable reserve is met. Otherwise, resort to mandatory load dropping.
9	Deficit Dispatchable Reserve	200,000	Insufficient capacity to meet reserve requirements (n-2)	This is not a problem if the interruptible reserve is met. Otherwise, resort to mandatory load dropping.
8	Over Generation	-800,000	The total minimum generation in the system exceeds the total demand	Identify "Must-Run Units" and shut down other units to eliminate excess capacity.
7	Deficit Regulating Reserve	400,000	Insufficient capacity to meet reserve requirements	Larger frequency excursions are expected without regulating reserve. Lower quality of service.

(continues to next page)

6	Deficit Contingency Reserve	500,000	Insufficient capacity to meet reserve requirements (n-1)	Automatic load dropping will cover for loss of generation if contingency reserve is insufficient.
5	Contingency	600,000	Violation in pre-defined contingency limits during single-outage conditions (n-1)	If risk involves system collapse, or islanding, implement necessary re-dispatch and load dropping.
4	Under Generation	800,000	The demand exceeds the total maximum generation in the system	Immediately implement mandatory load dropping, as necessary
3	Base Case Con-straint	900,000	Thermal loading limit violations of lines or transformers	Marginal overloads (i.e., <10% for 1 hour) should be allowed. Re-dispatch generation and drop load.
2	TCG Constraint	1,000,000	Import/Export constraints between areas	Immediately implement re-dispatch and/or load dropping as necessary.
1	Nodal Value of Lost Load	1,100,000	Localized deficiency in supply due to line or transformer loading limitations	Marginal overloads (i.e., <10% for 1 hour) should be allowed. Otherwise, drop local loads.

Table 2.4-2 Constraint Violation Coefficient Table

The MDOM treats the system/nodal energy balance requirement constraint, regional energy import/export constraint, regional reserve constraint and transmission line limit constraint as soft constraints (i.e. constraints that maybe violated), which are associated with prices (PHP/MWh) corresponding to the cost of constraint violation and thereby, signal risks to the power system. To ensure that the constraint violation is prioritized, the associated prices of the CVCs are set with a PHP 100,000 difference so that constraints resulting in the lowest reduction in the capability of the network, load or generating units will occur first. Also, as provided in WESM Rules Section 3.6.2.3, the CVC for the nodal energy balance constraint, known as the nodal value of lost load (VoLL), is currently set at a single value but may vary from node to node, and/or be set so as to reflect load shedding priorities. It should also be noted, as provided for in WESM Rules Section 3.6.2.1 (c), CVCs should be set so as to ensure that the prices produced by the MDOM will be appropriate in all circumstances, taking into consideration the processes defined in WESM Rules section 3.10.

In cases where the CVC prices were applied by the MDOM in the nodal prices, WESM Rules Clause 3.10.5 states that when the prices are believed to be in error,the Market Operator (MO) shall issue a pricing error notice (PEN), in which case the ex-post prices determined will also serve as ex-ante prices.

PRICING CONDITIONS IN THE PHILIPPINE WESM [20]

With the incorporation of CVCs in the MDOM, the MDOM may not produce prices that can be settled or are erroneous. According to WESM Rules Clauses 3.10.5 and 3.9.6, the MO may issue pricing error notices, in cases where no ex-ante or ex-post prices can be determined or communicated within the timetable or the calculated prices are believed to be in error. WESM Rules Clause 3.10.5 (a) and (b) further provide for the substitute prices that will be used in the settlement of market transactions in the trading intervals where pricing error notices are issued in either the ex-ante or ex-post market runs. When a pricing error notice is issued in the ex-ante market runs,the ex-post prices shall serve as the ex-ante prices. Meanwhile, when no ex-post prices can be determined or the calculated prices are believed to be in error, a re-run (the market re-run or MRR) of the MDOM shall be performed.However, if the resulting market prices are affected by network congestion and extreme nodal price

separations, the substitute prices are as provided for in the WESM Manual on “Methodology for Determining Pricing Errors and Price Substitution due to Congestion for Energy Transactions in the WESM” (PSM Manual).

Pricing errors are categorized according to cause, as either network congestion or non-congestion. Network congestion pricing errors are those that occur when the nodal prices are affected by network congestion as defined and determined pursuant to the criteria and price trigger set forth in the PSM Manual [22].

Pursuant to the PSM Manual, the Price Substitution Mechanism (PSM) shall be implemented in cases when, due to network congestion, the market pricing solutions show either of the following conditions: a) network CVCs, specifically for contingency constraint, base case constraint, transmission group constraint; or b) extreme nodal price separations. Extreme nodal price separations occur when the resulting prices show either of the following conditions (the price triggers):

Very high prices where:

$$ABS\,[LMPH / MCPH] > F \qquad \text{Eq. 11}$$

Very low or negative prices where:

$$ABS\,[(LMPH - LMPL) / MCPH] > F \qquad \text{Eq. 12}$$

Where:
ABS is the absolute value
LMPH is the highest locational marginal price
LMPL is the lowest locational marginal price
MCPH is the highest marginal price
F is the factor which has a value initially set at 1.23

On the other hand, non-congestion pricing errors are those that occur when no ex-ante prices or ex-post prices are determined or communicated within the timetable or when such prices are determined to be in error but are otherwise not classified as network congestion pricing errors under the PSM Manual. If pricing errors occur in the ex-ante or ex-post market runs, a pricing error notice shall be issued only for the market run where the pricing error occurred as determined by the MO. Figure 2.3-1 shows the process flow of the use of a substitute price for ex-ante and ex-post.

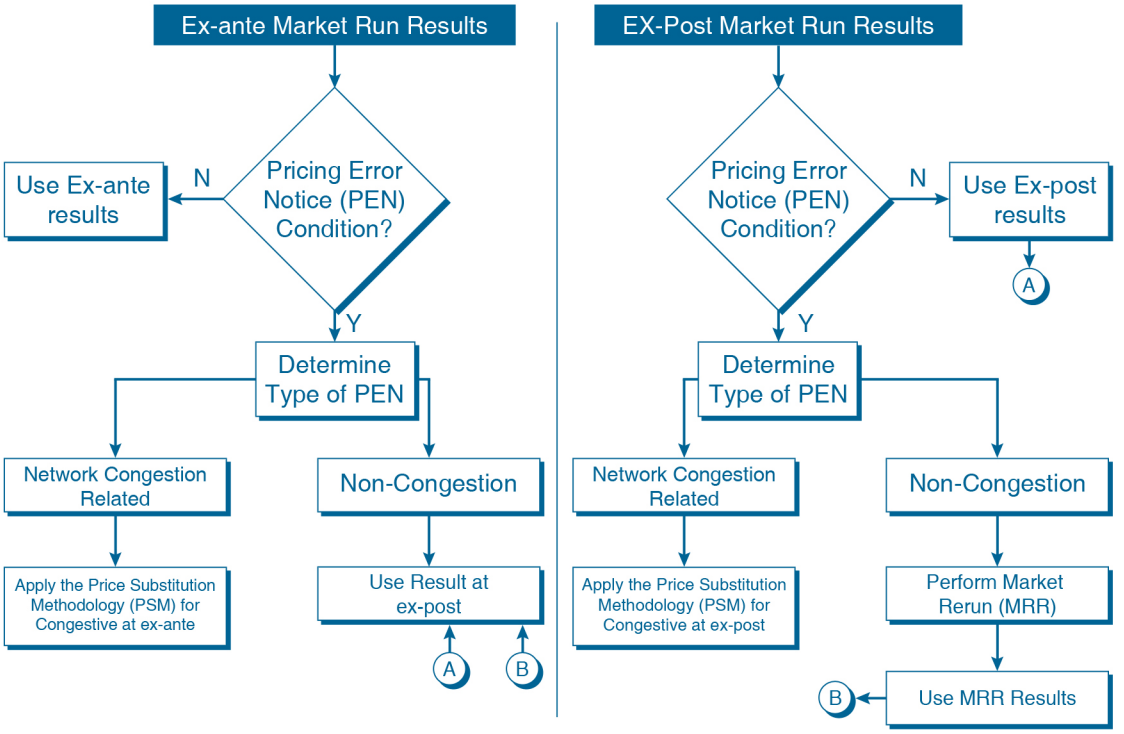

Figure 2.5-1 Determination of Substitute prices

SETTLEMENTS OF SPOT TRANSACTIONS IN THE PHILIPPINE WESM [4]

WESM Time Table

The timeline of market runs (ex-ante and ex-post) is shown below. The ex-ante schedule and prices for trading interval H are determined an hour before the trading interval, while the ex-post schedule and prices are determined right after the conclusion of the trading interval.

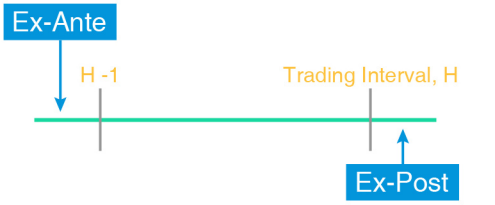

Figure 2.6-1 WESM Time Table

Total Trading Amount (TTA)

The Total Trading Amount for Generator, TTAgen, is the sum of the ex-ante energy trading amount and ex-post trading amount. On the other hand, the Total Trading Amount for the load, TTAload, is the sum of the ex-ante energy trading amount, ex-post trading amount, and line rental. This settlement process involves the determination of the ex-ante trading amount and ex-post trading amount adjusted for bilateral contract quantities in accordance with WESM Rules 3.13.7 and line rental for the load. It can be noted that the bilateral contracts are netted out in the TTA calculations.

$$TTA_{Gen} = EAETA + EPETA$$

Eq. 13

$$TTA_{Load} = EAETA + EPETA + LR$$

Eq. 14

Ex-Ante Energy Trading Amount (EAETA)

The ex-ante trading amount for the trading interval is determined as the ex-ante energy settlement price multiplied by the difference of ex-ante energy settlement quantity and Bilateral Contract Quantity. These are outputs of the MDOM representing the expected prices and quantities.

$$EAETA = (EAP \times (EAQ - BCQ))$$

Eq. 15

Where
EAETA is the ex-ante energy trading amount
EAP or EAESP is the ex-ante energy nodal price
EAQ or EAQSI is the ex-ante energy quantity scheduled for injection
=0.5 x (XAGQ+XAIGQ)
XAGQ is the ex-ante energy target quantity
XAIGQ is the ex-ante energy initial quantity
BCQ is the physical bilateral contract quantity of energy

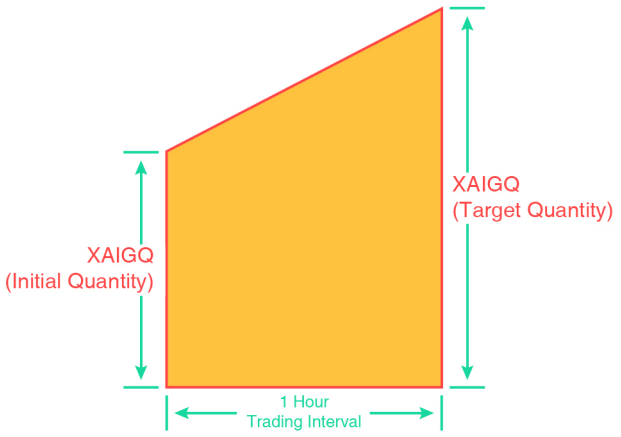

Figure 2.6.3-1 Ex-Ante Quantity

Ex-Post Energy Trading Amount (EPETA)

The ex-post trading amount for the trading interval is determined as the ex-post energy settlement price multiplied by the difference of the ex-post energy settlement quantity and ex-ante energy settlement quantity. These are outputs of the MDOM representing the actual prices and quantities. The EPETA will cover the deviation of a particular resource from its scheduled quantity.

$$EPETA = EPP^{*} (MQ-EAQ)$$

Eq. 16

Where
EPETA is the ex-post energy trading amount
EPP or EPESP is the ex-post energy nodal price
MQ or AQEI is the ex-post energy quantity, also equal to the metered quantity
EAQ or EAQSI is the ex-ante energy quantity scheduled

Line Rental (LR)

For bilateral contracts that are netted out or settled outside of the market, the line rental amount that will be charged with the bilateral contract quantity is the price differential between the sending and the receiving nodes. WESM Rules 3.13.12 provides the formula for the calculation of the line rental as follows:

$$LR = BCQ\ (EAP_{l}\text{-}EAP_{g})$$

Eq. 17

Where
LR is the line rental
EAPg is the ex-ante energy generator nodal price
EAPl is the ex-ante energy load nodal price

It can be noted that presently, the line rental amount is charged to the DisCos only and not to the GenCos. However, since, LRs are detailed in the WESM Billing Statement, future contracts of the DisCos and GenCos may include provisions of sharing this LR cost.

Declaration of Bilateral Contract Quantities

According to WESM Rules 3.13.1.1, trading participants who sell electricity (GenCo) and wish their bilateral contracts to be accounted for in the settlement shall, after each trading day, in accordance with the time table:

a. Submit a schedule to the Market Operator, specifying the MWH bilateral sell quantities at each relevant market trading node in each of the trading intervals of that day;
b. Identify the counterparty to the bilateral contract; and
c. Provide evidence that the counterparty to the contract agrees with the submission made under Clause 3.13.1.1.

SIMPLIFICATION OF BILATERAL CONTRACTS

A bilateral contract is an energy supply arrangement that is directly and privately negotiated between the DisCo and GenCo. It is committed by the GenCos to directly supply power to a large load of the DisCo. These contracts are widely applied in competitive electricity markets. Contract parties should distribute electricity deliveries by time intervals during a contract period in an optimal way to get the highest profit and to elaborate a strategy of participating in the spot and retail markets [5].

Take or Pay Bilateral Contract

Most bilateral contracts have Take or Pay Provisions. This is a bilateral contract model that binds the DisCo to pay in full regardless if the quantity is actually delivered or not. One of the characteristics of this contract is having Minimum Energy Quantity (MEQ) that is paid regardless if it is actually delivered or not.This type of contract normally contains two components –the fixed and variable costs.

The fixed costs include the capacity charge and the fixed operating charge [7].

1. Capacity Charge (CC) – represents payment for the capacity of the plant. It provides for the recovery of the development of the capital costs, financing costs and a return on equity. It is equal to the MEQ multiplied by the capital cost recovery rate and it is payable by the DisCo regardless of the quantity of energy actually taken.

$$CC = CCR*MEQ \quad \text{Eq. 18}$$

Where
CC is the Capacity Charge(PHP)
CCR is the Capital Cost Recovery Rate(PHP/MWh)
MEQ is the Minimum Energy Quantity (MWh)

2. Fixed Operating Charge – represents payment for the fixed operating and maintenance costs of the plant regardless of the energy actually purchased. It is equal to the MEQ multiplied by the fixed operating recovery rate of the plant, including index price adjustments, and it is payable by the DisCo regardless of the quantity of the energy actually taken.

$$FOC = FOMR*MEQ \quad \text{Eq. 19}$$

Where
FOC is the Fixed Operating Charge (PHP)
FOMR is the FixedOperating Recovery Rate(PHP/MWh)

On the other hand, the Variable Costs include the Variable Operating Charge, Fuel Charge, and the Excess Generation Charge [7].

1. Variable Operating Charge – represents the payment for the variable operating and maintenance costs of the plant. It is equal to the energy actually purchased multiplied by the variable operating rate of the plant.

$$VOC = VOCR*NEO \quad \text{Eq. 20}$$

Where
VOC is the variable operating and maintenance costs(PHP)
VOCR is the variable operating rate of the plant (PHP/MWh)
NEO is the net electrical output (MWh)

2. Fuel Charge – represents the payment for the fuel consumed in generating the electrical energy that was actually purchased subject to the limits of the guaranteed heat rate of the plant.

$$FC = FQ*FP \quad \text{Eq. 21}$$

Where
FC is the Fuel Charge (PHP)
FQ is the quantity of fuel consumed (MMBtu)
FP is the weighted average price of fuel (PHP/MMBtu)

3. Excess Generation Charge – represents payment for the energy in excess of the MEQ actually purchased by the DisCo. It is equal to the excess generation charge multiplied by the energy generation in excess of the MEQ.

$$EGC = DCCR*XEO \quad \text{Eq. 22}$$

Where
EGC is the Excess Generation Charge (PHP)
DCCR is the discounted capacity cost recovery rate (PHP/MWh)
XEO is the Net Electrical Output in Excess of MEQ (MWh)

Thus, the bilateral contract cost is

$$BC = Fixed\ Cost + Variable\ Cost \quad \text{Eq. 23}$$

$$= CC + FOC + VOC + FC + EGC \quad \text{Eq. 24}$$

Translating the Take or Pay Bilateral Contract

Since the energy transactions and declaration of bilateral contract quantities are hourly in the WESM, there is a need to convert the five to ten year horizon of the Take or Pay Provision to hourly data.

To calculate the daily minimum declaration of bilateral contract quantities, the fixed costs should be considered. The weighted daily loads may be used to pro-rate each day. Also, an allowable percentage of deviation maybe introduced to compensate the tolerable forecast error. In doing so, the following formula may be deduced:

$$BCQmin_{D_i} = (MEQ)\left(\frac{D_i}{\sum_1^n D_n}\right)(\%E) \quad \text{Eq. 25}$$

Or alternatively,

$$\mathrm{BCQmin_{D_i}} = \left(\frac{\mathrm{CC + FOC}}{\mathrm{CCR+FOMR}}\right)\left(\frac{\mathrm{D_i}}{\sum_1^n \mathrm{D_n}}\right)(\%E) \quad \text{Eq. 26}$$

Where
BCQminDi is the minimum bilateral contract quantity that should be declared for Di (MW)
CC is the Capacity Charge(PHP/MWh)
CCR is the Capital Cost Recovery Rate (PHP/MWh)
FOC is the Fixed Operating Charge (PHP/MWh)
FOMR is the fixed operating recovery rate (PHP/MWh)
MEQ is the Minimum Energy Quantity (MWh)
Di is the days or group of days targeted to have the same bilateral contract constraints
Dn is the number of Dis
%E is the tolerable error in the forecasting of loads

To calculate the daily maximum declaration of bilateral contract quantities, the Total Bilateral Contract costs should be considered. The weighted daily loads may be used to pro-rate each day. In doing so, the following formula may be deduced:

$$BCQmax_{D_i} = (MEQ+XEO)\left(\frac{D_i}{\sum_1^n D_n}\right)(\%E)$$

Eq. 27

Where
BCQmaxDi is the maximum bilateral contract quantity that should be declared for Di (MW)
MEQ is the Minimum Energy Quantity (MWh)
XEO is the Net Electrical Output in Excess of MEQ (MWh)
Di is the days or group of days targeted to have the same bilateral contract constraints
Dn is the number of Dis
%E is the tolerable error in the forecasting of loads

Summary of Adapted References in the Study

All of the reference papers in Section 2.2 from [8], [9], [10],[11] and [12]; Section 2.3 from [1]; and Section 2.7.1 from [7], used only a Single-Settlement System or considered a single spot price. Spot transactions were simply spot quantities that are net of bilateral contracts multiplied by the spot market price. This single spot market price was adapted in the Single-Settlement System model discussed and derived in Part 3, Formulation Section 3.1. It can be noted that the penalties arising from adjusting the bilateral quantities discussed in Section 3.2 from [1] were incorporated in the model. However, assessment of risks from the references discussed in Section 2.2 was not included in the model since the values for spot price and energy demand are already known considering a Day-After (D+1) declaration of bilateral contract quantities as per WESM Rules 3.13.1.1.

Considering the Philippine WESM set-up with the following conditions:

1. Two-Settlement System;
2. Day-After(D+1) Declaration of bilateral contract quantities; and
3. Final prices, schedules, and metered quantities are available upon declaration of hourly contract quantities,

The Two-Settlement System model was derived from [1]. This model is almost similar with the Single-Settlement System in which the spot transactions were replaced by the Total Trading Amount Formula discussed in Section 2.6. This model considered the line rental trading amount enabling some variables to be further simplified. Again, assessment of risks from the references discussed in Sections 2.2 were not included in this model since the values for spot price and energy demand are already known considering a D+1 declaration of

bilateral contract quantities as per WESM Rules 3.13.1.1. Further discussions on this could be found in Part 3, Formulation Section 3.2.

MARKET SETTLEMENT SYSTEMS

Most studies pertain only to having one spot price. However, in the Philippine WESM, two spot prices are used –ex-ante and ex-post. Thus, for the purposes of this study, markets using one spot price shall be modeled as the Single-Settlement System, while the markets using two spot prices shall be modeled as the Two-Settlement System.

SINGLE-SETTLEMENT SYSTEM

Since the reference paper used a Single-Settlement System, there is a need to harmonize the data collected to the reference paper's optimization model. For this case, the single settlement market data on spot price shall be based on the Final Ex-Ante Price to account for the hour-ahead scheduling results, while the corresponding energy quantity shall be based on the Ex-post Quantity or metered quantity so that there is no need to account for the imbalance.

On the other hand, the objective function in equation (7) maximizes the profit of the DisCos considering the total collection of sales from customers and the total payment for the generation cost. For simplicity, it could be rewritten such that it minimizes the payment for generation cost. From this point-of-view, the total collection of sales from customers will not be part of the objective function as shown in equation(28) below.

$$S_n + \sum_{t=T_c}^{T_N} P_d^t (X_{kN}^t + X_{sN}^t) = Max \sum_{t=T_c}^{T_N} (P_{sF}^{\sim t} (X_{ssN}^t - X_{sN}^t) - p^t x^t) - P_{ovd}^t (|x^t - X_{kN}^t - X_{sN}^t|)$$

Eq. 28

Let G_n be the generation cost, then objective function becomes minimization.

$$MinG_n = \sum_{t=T_c}^{T_N} (P_{sF}^{\sim t} (X_{sN}^t - X_{ssN}^t) + p^t x^t) + P_{ovd}^t (|x^t - X_{kN}^t - X_{sN}^t|)$$

Eq. 29

Furthermore, equations (8) and (9) and equations (30) and (31) can be derived as follows:

$$X_{ssN}^t = x^t - X_{kN}^t$$

Eq. 30

$$X_{sN}^t = X_{dF}^t - X_{kN}^t$$

Eq. 31

Substituting equations (30) and (30) to equation(29), equation(29) becomes:

$$MinG_n = \sum_{t=T_c}^{T_N} (P_{sF}^{\sim t} (X_{dF}^t - x^t) + p^t x^t) + P_{ovd}^t (|x^t - X_{kN}^t - X_{sN}^t|)$$

Eq. 32

For simplicity and harmony of the usage of variables, equation (32) can be re-written as follows:

$$MinG_n = \sum_{t=T_c}^{T_N} (EAP_l (MQ - BCQ_f) + BCP * BCQ_i) + BCF(|BCQ_f - BCQ_i|)$$

Eq. 33

Where
$P_{sF}^{\sim t} = EAP_l$ is the Ex-Ante Price at the load
$X_{dF}^{t} = MQ$ is the Metered Quantity/Actual Energy Serve
$x^t = BCQ_i$ is the Bilateral Contract Quantity Initial Agreement
$X_{kN}^{t} + X_{sN}^{t} = BCQ_f$ is the Bilateral Contract Quantity Final Declaration
$p^t = BCP$ is the Bilateral Contract Price
$P_{ovd}^{t} = BCF$ is the Bilateral Contract Penalty Cost

Furthermore, removing the constants in equation (33) such as $EAP_l * MQ$ and $BCQ_i * BCP$, as well as using $|\Delta BCQ|$ in lieu of $|BCQ_f - BCQ_i|$, the new objective function O_n can be further simplified to:

$$O_n = Min \sum_{t=T_c}^{T_N} \left(-EAP_l * BCQ_f + BCF(|\Delta BCQ|)\right)$$

Eq. 34

Subject to

$$BCQ_{f_\min} \leq BCQ_f \leq BCQ_{f_\max}$$

Eq. 35

$$\sum_{h=1}^{24} BCQ_{f_\min} \leq \sum_{h=1}^{24} BCQ_f \leq \sum_{h=1}^{24} BCQ_{f_\max}$$

Eq. 36

In which equation (35) represents the hourly BCQ constraints, while equation (36) represents the daily BCQ constraints.

After using the objective function in (34), the total generation cost may be computed by returning the Fixed Spot Market Costs as follows:

$$G_n = \sum_{t=T_c}^{T_N} \left(EAP_l * MQ + BCP * BCQ_i + -EAP_l * BCQ_f + BCF(|\Delta BCQ|)\right)$$

Eq. 37

Note that the following expressions are constants:

$EAP_l * MQ$ is the Fixed Spot Market Cost
$BCP * BCQ_i$ is the Fixed Bilateral Contract Cost

Two-Settlement System

To fully adopt the market data of the WESM, the objective function in III.2 was modified. The two-settlement system can be implemented by modifying the spot market transactions in equation (33). This means this portion, $EAP_l\,(MQ - BCQ_f)$, will be changed to TTA for load considering ex-ante (EAETA), ex-post (EPETA), and line rental (LR) as mentioned in equation (17). The modification on the objective function is shown below:

$$MinG_{2n} = \sum_{t=T_c}^{T_N} \left(EAP_l\left(EAQ - BCQ_f\right) + EPP_l(MQ - EAQ) + BCQ\left(EAP_l - EAP_g\right) + BCP * BCQ_f\right) + BCF\left(\left|BCQ_f - BCQ_i\right|\right)$$

Eq. 38

In addition to the changes associated with the spot transactions, the portion $BCP * BCQ_i$ was modified to $BCP * BCQ_f$. This is to ensure that the adjustments to the contract quantity are still paid on the contract price with the addition of the penalty cost. Using the latter means that the adjustments to the contract quantity are paid based on the penalty cost. The penalty cost is not on top of the contract price.

Furthermore, equation (38)can be further simplified to equation (39) by expanding and removing the variables that were cancelled.

$$MinG_{2n} = \sum_{t=T_c}^{T_N}\left(EAP_l * EAQ + EPP_l * MQ - EPP_l * EAQ - EAP_g * BCQ_f + BCP * BCQ_f\right) + BCF\left(|BCQ_f - BCQ_i|\right)$$

Eq. 39

In addition, removing the constants in equation (39) such as $EAP_l * EAQ + EPP_l * MQ - EPP_l * EAQ$, as well as using $|\Delta BCQ|$ in lieu of $|BCQ_f - BCQ_i|$, the new objective function O_{2n} can be further simplified to

$$MinO_{2n} = \sum_{t=T_c}^{T_N}\left(\left(BCP - EAP_g\right) * BCQ_f + BCF * \left(|\Delta BCQ|\right)\right)$$

Eq. 40

subject to the same constraints in (35) and (36).

After using the objective function in (40), the total generation cost may be computed by returning the Fixed Spot Market Costs shown as follows:

$$G_{2n} = \sum_{t=T_c}^{T_N}\left(EAP_l * EAQ + EPP_l * MQ - EPP_l * EAQ + \left(BCP - EAP_g\right) * BCQ_f + BCF * \left(|\Delta BCQ|\right)\right)$$

Eq. 41

Note that the following expressions are constants $EAP_l * EAQ + EPP_l * MQ - EPP_l * EAQ$ is the Fixed Spot Market Cost

Furthermore, the GenCo'scontract sales can be computed as the sum of payments under contract and the penalties incurred during the process.

$$G_{2s} = \sum_{t=T_c}^{T_N}\left(BCP * BCQ_f + BCF * \left(|\Delta BCQ|\right)\right)$$

Eq. 42

METHODOLOGY

PROCESS FLOW

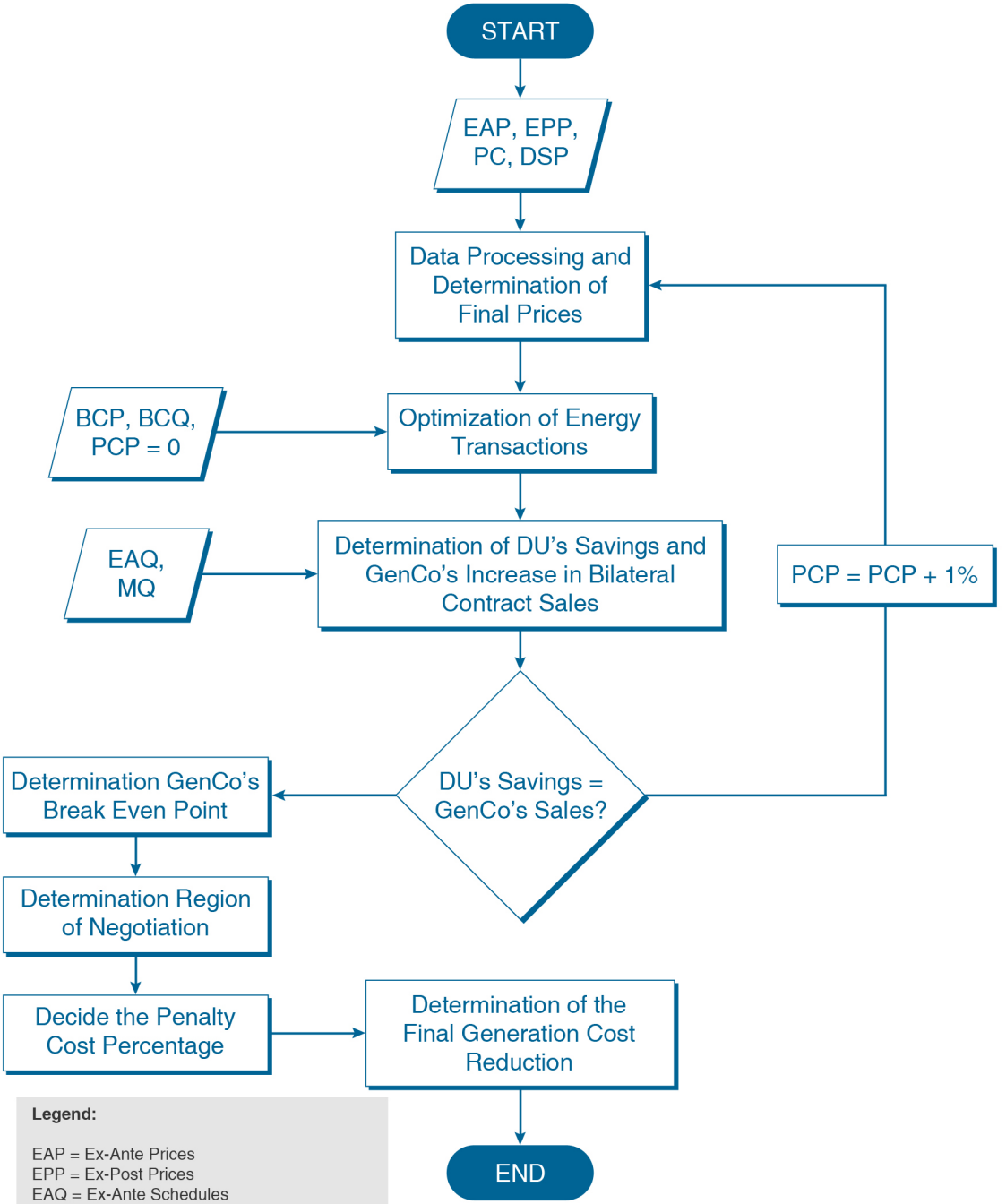

Figure 4.1-1 Process Flow

DISCUSSION

Having derived the optimization models for a Single-Settlement System and Two-Settlement System in Part 3, the model is now ready to be tested using a different set of data. Table 5-1 summarizes the test cases conducted in this study and its corresponding objectives.

Test Case Number	Description	Objective	Discussion Section
5.1	Replication of Reference Paper's Work	To replicate the results of the reference paper ensuring the correctness of the basis of the formulation of the Single-Settlement System and Two- Settlement System	5.1
5.2	Application of the Reference Paper's Model to the Philippine Set-Up	To implement the modified 12-hour Philippine data in the exact optimization model of the reference paper	5.2
5.3	Single-Settlement System	To implement the modified 30-day Philippine data in the optimization model derived in section 3.1	5.3
5.4	Two-Settlement System	To implement the processed 30-day Philippine data in the optimization model derived in section 3.2 and compare the results with Test 5.3	5.4
5.5	Match Point Penalty Cost	To determine the match point using the Two-Settlement System wherein the penalty cost percentage is beneficial to both parties and to propose the region of negotiation between the GenCos and DisCos	5.5
5.6	Freeing the Hourly and Daily BCQ Constraints	To determine the effect of freeing bilateral contract constraints at the region of negotiation	5.6
5.7	Using the Two-Settlement System Model to the Other data	To test whether the two-settlement optimization model will yield similar results using a different set of data	5.7

Table 5-2 Summary of Test Cases

REPLICATION OF REFERENCE PAPER'S WORK [1]

The reference paper provided a numerical example to illustrate its optimization model on the 6 stages of bilateral contract correction. It is assumed in the example that BC is concluded between supply and generation companies. Contract period consists of four time intervals of equal duration. Initially, both parties agreed that the total BCQ for four intervals is 78 MWh payable at 70.51 USD/MWh. The correction period is one interval and the price of electricity at the end consumer is 100 USD/MWh. Other assumptions are the following:

- Fines on the supplier in case of delivery reduction, as well as fine on the buyer in case of BC cancellation is 75 USD/MWh; and
- Fines on the buyer in case of delivery over-withdrawing is 72.5 USD/MWh.

The initial condition is shown in the table below. Notice that there is a negative spot transaction because there is a quantity of BCQ sold to the spot market (column 4). Thus, the spot market will pay the seller. Also, initially, the total profit of the DisCo is USD 1503.98.

Interval	Energy (MW)	BCQ Delivered (MW)	BCQ Sold to SM (MW)	Energy Bought from SM (MW)	Total BCQ (MW)	Spot Price (USD/ MW)	BC Transaction		Spot Transaction (USD)	Total Cost (USD)	Total Profit (USD)
							Original BC (USD)	Penalty (USD)			
1	9.8	8	0	1.8	8	65	564.08	0	117	681.08	298.92
2	11.4	5	0	6.4	5	70.37	352.55	0	450.368	802.918	337.082
3	14.5	14.5	43.5	0	58	71.75	4089.58	0	-3,121.13	968.455	481.545
4	13	7	0	6	7	70	493.57	0	420.00	913.57	386.43
Total	48.7	34.5	43.5	14.2	78		5499.78	0	-2,133.76	3,366.02	1,503.98

Table 5.1-1 Initial Condition of Spot and Bilateral Contract Transactions

Stage 1. Updating of Forecast Demand

After updating the demand forecast, it is expected that there will be changes in the total energy that will be delivered to the DisCo. Notice that the energy in intervals 3 and 4 were changed and the total energy was changed from 48.7 MW to 42.2 MW. The decrease in the MW delivery implies a corresponding decrease in the profit of the DisCo to USD 1207.56. This is 0.04% away from the reference paper's results of USD 1207.10.

Interval	Energy (MW)	BCQ Delivered (MW)	BCQ Sold to SM (MW)	Energy Bought from SM (MW)	Total BCQ (MW)	Spot Price (USD/ MW)	BC Transaction		Spot Transaction (USD)	Total Cost (USD)	Total Profit (USD)
							Original BC (USD)	Penalty (USD)			
1	9.8	8	0	1.8	8	65	564.08	0	117	681.08	298.92
2	11.4	5	0	6.4	5	68.26	352.55	0	436.864	789.414	350.586
3	10	10	48	0	58	69.6	4089.58	0	-3,340.80	748.78	251.22
4	11	7	0	4	7	74.9	493.57	0	299.60	793.17	306.83
Total	42.2	30	48	12.2	78		5499.78	0	-2,487.34	3,012.44	1,207.56

Table 5.1-2 Stage 1: Updating of Forecast Demand

Stage 2. Bilateral Contract Correction

Applying the optimization model in equation (7), the resulting schedules are shown below. Notice that part of the BC transaction includes the penalty due to BC correction, since the 7 MW initial BCQ for interval 4 was changed to 65 MW. The resulting schedules output a total profit of USD 1346.76 or an increase of USD 139.20. This is 0.03% away from the reference paper's results of USD 1346.30.

Interval	Energy (MW)	BCQ Delivered (MW)	BCQ Sold to SM (MW)	Energy Bought from SM (MW)	Total BCQ (MW)	Spot Price (USD/ MW)	BC Transaction		Spot Transaction (USD)	Total Cost (USD)	Total Profit (USD)
							Original BC (USD)	Penalty (USD)			
1	9.8	8	0	1.8	8	65.00	564.08	0	117.00	681.08	298.92
2	11.4	5	0	6.4	5	68.26	352.55	0	436.86	789.41	350.59
3	10	10	48	0	58	69.60	4089.58	0	-3,340.80	748.78	251.22
4	11	11	54	0	65	74.90	493.57	4205	-4,044.60	653.97	446.03
Total	42.2	34	102	8.2	136		5499.78	4205	-6,831.54	2,873.24	1,346.76

Table 5.1-3 Stage 2: Bilateral Contract Correction

Stage 3. Bilateral Contract Cancellation

The resulting initial condition was also simulated in case of cancellation of the bilateral contract. The resulting profit is (–) USD3645.39, implying a loss for the DisCo. The schedule is shown below.This is almost equal to the reference paper's result of USD 3,645.40.

Interval	Energy (MW)	BCQ Delivered (MW)	BCQ Sold to SM (MW)	Energy Bought from SM (MW)	Total BCQ (MW)	Spot Price (USD/ MW)	BC Transaction		Spot Transaction (USD)	Total Cost (USD)	Total Profit (USD)
							Original BC (USD)	Penalty (USD)			
1	9.8	8	0	1.8	8	65	564.08	0	117	681.08	298.92
2	11.4	5	0	6.4	5	68.26	352.55	0	436.864	789.414	350.586
3	10	0	0	10	0	69.6	0	4350	696.00	5046	-4046
4	11	0	0	11	0	74.9	0	525	823.90	1348.9	-248.9
Total	42.2	13	0	29.2	13		916.63	4875	2,073.76	7,865.39	-3,645.39

Table 5.1-4 Stage 3: Bilateral Contract Cancellation

Stage 4. Comparison of Results

Based on the results for stages 1-3, as summarized in the table below, it is now profitable to recommend the bilateral contract correction (result of Stage 2).

Stages	Action	Total Profit (USD)		
		Replication	Data on Reference Paper	Difference
Stage 1	Update Forecast and Demand	1,207.56	1,207.10	0.04%
Stage 2	BC Correction	1,346.76	1,346.30	0.03%
Stage 3	BC Cancellation	-3,645.39	3,645.4	0.00%

Table 5.1-5 Results Comparison for the 3 Stages

Stage 5 and Stage 6. Recommendation to Generation Company for implementation

The total payment to the GenCo through bilateral contract after bilateral contract correction will increase from USD 5499.78 to USD 9704.78, or effectively increased the BC rate from USD 70.51/MWh to USD 71.36/MWh. This is a 1.21% increase in the original BC agreement, which may be appealable to the GenCo. It can also be noticed that the results of the simulation are very close to the results published in the referenc paper. Thus, the reference paper was successfully replicated.

APPLICATION OF THE REFERENCE PAPER'S MODEL TO THE PHILIPPINE SET-UP

To further test model, a 12-hour simulation on the data for the month of May 2009 was conducted. The data was gathered from the market prices and schedules in the WESM website. On the other hand, monthly data on the generation charges were gathered from the pricate DisCo website. The data are not readily applicable to the optimization model of the paper, thus, additional assumptions were included in the modeling, and these are:

Intervals
- No. of Intervals : 12

BC Price and Quantity
- BC Price : PHP 5599.7/MW
- Max BC Quantity : 25 MW

Spot Price and Quantity
- Spot Price : Use Ex-Ante Price
- Spot Quantity : Use Ex-Ante Quantity

Fines
- BCQ Over-withdrawing : PHP 5700.00/MW

Since the collected data is historical in nature, the stage 1 process in the BC correction is not performed because it involves forecasting the new spot market and price. The optimization model in equation (7) was used. The total revenue for the DisCo that was assumed to be constant in the optimization model.

The initial condition set by the inputs and assumptions is summarized in the table below.

Interval	Energy (MW)	BCQ Delivered (MW)	BCQ Sold to SM (MW)	Energy Bought from SM (MW)	Total BCQ (MW)	Spot Price (PHP/MW)	BC Transaction		Spot Transaction (PHP/MW)	Total Cost (PHP/MW)
							Original BC (PHP/MW)	Penalty Due to Correction (PHP/MW)		
1	22.00	11.40	0.00	10.60	11.40	6,399.87	63,836.58	0.00	67,838.62	131,675.20
2	20.25	10.50	0.00	9.75	10.50	5,347.02	58,796.85	0.00	52,133.45	110,930.30
3	19.00	8.30	0.00	10.70	8.30	5,336.95	46,477.51	0.00	57,105.36	103,582.88
4	19.00	8.00	0.00	11.00	8.00	4,658.54	44,797.60	0.00	51,243.94	96,041.54
5	19.00	7.60	0.00	11.40	7.60	4,313.49	42,557.72	0.00	49,173.79	91,731.51
6	18.17	0.70	0.00	17.47	0.70	3,170.70	3,919.79	0.00	55,381.56	59,301.35
7	17.00	0.80	0.00	16.20	0.80	2,541.93	4,479.76	0.00	41,179.27	45,659.03
8	17.00	8.30	0.00	8.70	8.30	6,664.12	46,477.51	0.00	57,977.84	104,455.35
9	17.33	9.70	0.00	7.63	9.70	6,628.52	54,317.09	0.00	50,597.70	104,914.79
10	19.00	19.00	2.10	0.00	21.10	12,913.02	118,153.67	0.00	-27,117.34	91,036.33
11	22.00	22.00	0.90	0.00	22.90	12,747.97	128,233.13	0.00	-11,473.17	116,759.96
12	22.00	22.00	1.80	0.00	23.80	10,339.07	133,272.86	0.00	-18,610.33	114,662.53
Total	231.75	128.30	4.80	103.45	133.10		745,320.07	0.00	425,430.69	1,170,750.76

Table 5.2-1 Initial Conditions for Bilateral Contract Correction

The resulting cost is PHP/kWh 5.05, which was computed by dividing the total cost by the total energy. This initial condition was used and subjected to bilateral correction model following equation (7) for the Single-Settlement System. The result is summarized below in Table 5.2-2

Interval	Energy (MW)	BCQ Delivered (MW)	BCQ Sold to SM (MW)	Energy Bought from SM (MW)	Total BCQ (MW)	Spot Price (PHP/ MW)	BC Transaction		Spot Transaction (PHP/MW)	Total Cost (PHP/MW)
							Original BC (PHP/ MW)	Penalty Due to Correction (PHP/MW)		
1	22.00	22.00	3.00	0.00	25.00	6,399.87	63,836.58	77,520.00	-19,199.61	122,156.97
2	20.25	10.50	0.00	9.75	10.50	5,347.02	58,796.85	0.00	52,133.45	110,930.30
3	19.00	8.30	0.00	10.70	8.30	5,336.95	46,477.51	0.00	57,105.36	103,582.88
4	19.00	8.00	0.00	11.00	8.00	4,658.54	44,797.60	0.00	51,243.94	96,041.54
5	19.00	7.60	0.00	11.40	7.60	4,313.49	42,557.72	0.00	49,173.79	91,731.51
6	18.17	0.70	0.00	17.47	0.70	3,170.70	3,919.79	0.00	55,381.57	59,301.36
7	17.00	0.80	0.00	16.20	0.80	2,541.93	4,479.76	0.00	41,179.27	45,659.03
8	17.00	17.00	8.00	0.00	25.00	6,664.12	46,477.51	95,190.00	-53,312.96	88,354.55
9	17.33	17.33	7.67	0.00	25.00	6,628.52	54,317.09	87,209.98	-50,818.66	90,708.42
10	19.00	19.00	6.00	0.00	25.00	12,913.02	118,153.67	22,230.00	-77,478.12	62,905.55
11	22.00	22.00	3.00	0.00	25.00	12,747.97	128,233.13	11,970.00	-38,243.91	101,959.22
12	22.00	22.00	3.00	0.00	25.00	10,339.07	133,272.86	6,840.00	-31,017.21	109,095.65
Total	231.75	155.23	30.67	76.52	185.90		745,320.07	300,959.98	36,146.91	1,082,426.96

Table 5.2-2 Stage 2 Bilateral Contract Correction

After BC correction, there were changes in the declaration of BCQ, hereby leading to penalties. However, the resulting total cost is much lower than the initial condition. The BC correction leads to a decrease in the effective generation cost of up to PHP/kWh 4.67 or 0.38 PHP/kWh less. This means that by applying the BC correction, the cost of generation may decrease up to 7.54%.

Also, the payment to the generators increased by PHP 300 959.98 as a result of the penalties of higher BCQ declaration. This means that the effective BC price at the generator end increased to 5.63 PHP/kWh from 5.60 PHP/kWh or 0.51%. Thus, BCQ correction benefits both the GenCo and the DisCo.

SINGLE-SETTLEMENT SYSTEM

The market data used in the test case was based on the October 2011 billing period (from 26 September 2011 to 25 October 2011) for a Distribution Company having bilateral contracts with six Generation Companies paired in a total of 12 Generator Market Trading Nodes (MTN). The October 2011 billing period was chosen because of the very high market clearing prices in which the Customer Effective Spot Settlement Price(ESSP) increased by 62% from PHP 5.080/kWh in September 2011 to PHP 8.218/kWh in the October 2011 billing month. The ex-ante prices are shown in Figure 5.3-1. The high prices were due to the tight supply condition wherein there was only a thin margin between the offered capacity and the demand as shown in the Figure 5-2. This happened particularly towards the latter part of the month, as a result of the combined effect of the natural gas supply limitation (due to the scheduled shutdown of the Malampaya onshore natural gas complex which commenced on 20 October 2011), plant outages, and Luzon-Visayas HVDC link maintenance.

MARKET PRICES, EX-ANTE

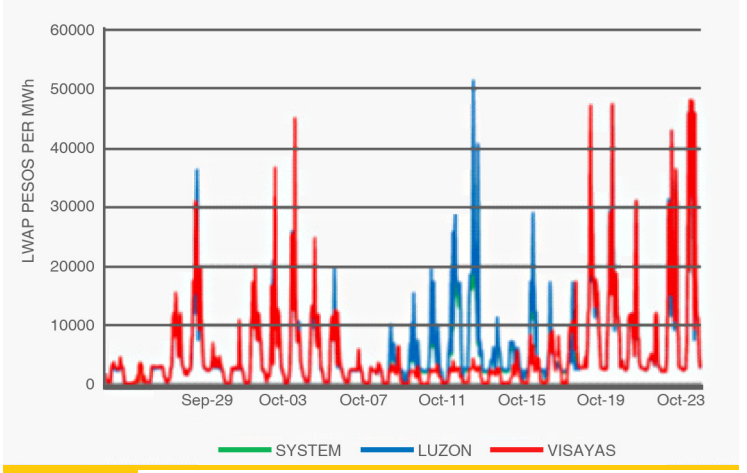

Figure 5.3-1 October 2011 Energy Ex-Ante Prices

SUPPLY AND DEMAND, SYSTEM

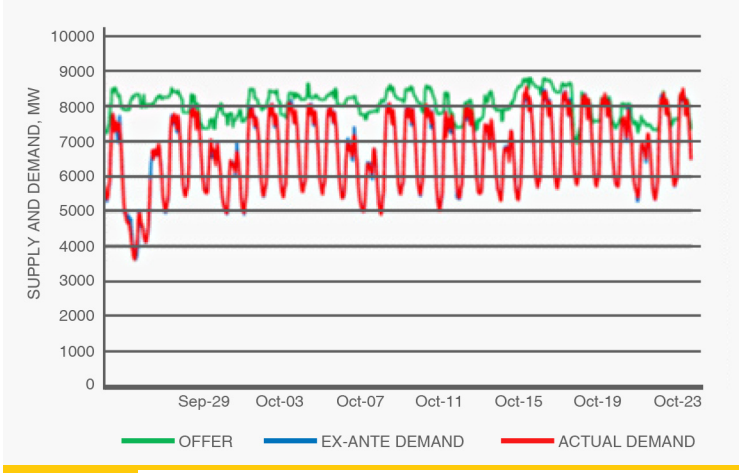

Figure 5.3-2 October 2011 Supply-Demand Condition

On the other hand, the bilateral contract quantities and prices were assumed based on Power Supply Contract between the DisCo and GenCos. The hourly and daily limitations were based on the historical data, while the bilateral contract prices were assumed based on the Energy Regulatory Commission (ERC)-approved rates. Table 5.3-1 shows the bilateral contract data needed as input to the optimization model.

Generator	BC Price (PHP/MW)	Daily		Hourly	
		Min (MW)	Max (MW)	Min (MW)	Max (MW)
Gen 1	4,715.80	1,122.04	2,356.38	0.00	155.85
Gen 2	4,855.40	720.00	720.00	30.00	30.00
Gen 3	9,431.60	0.00	48.20	0.00	12.98
Gen 4	9,431.60	0.00	48.20	0.00	12.35
Gen 5	6,664.00	2,071.00	2,355.00	60.00	105.00
Gen 6	9,826.60	0.00	343.00	0.00	52.00
Gen 7	4,715.80	0.00	435.78	0.00	46.00
Gen 8	4,715.80	0.00	435.78	0.00	50.68
Gen 9	4,715.80	0.00	284.00	0.00	23.00
Gen 10	4,855.40	360.00	360.00	15.00	15.00
Gen 11	4,855.40	360.00	360.00	15.00	15.00
Gen 12	7,346.40	0.00	360.00	0.00	16.00

Table 5.3-1 Bilateral Contract Data of the Distribution Company

The initial condition is summarized in Table 5.3-2.

Day	Total Gen Cost (PHP)	Fixed Spot (PHP)	BCQ Adjustments (PHP)	BCQ Payment (PHP)	Penalty (PHP)
1	36,665,947.57	14,126,875.91	(14,393,772.75)	36,932,844.41	-
2	36,346,169.95	3,820,814.12	(3,846,618.75)	36,371,974.58	-
3	37,064,412.55	14,040,206.27	(13,672,098.70)	36,696,304.98	-
4	39,445,930.95	42,030,491.89	(40,115,178.32)	37,530,617.38	-
5	41,769,798.86	81,087,908.71	(7,732,747.74)	37,814,637.88	-
6	35,883,230.32	20,267,996.63	(19,275,322.11)	34,890,555.80	-
7	31,462,338.70	12,851,838.50	(11,975,657.40)	30,586,157.60	-
8	39,337,273.64	50,687,513.25	(47,709,096.74)	36,358,857.13	-
9	38,487,113.88	52,145,607.96	(51,687,658.38)	38,029,164.30	-
10	36,547,849.36	63,906,364.61	(65,037,981.74)	37,679,466.50	-
11	38,565,358.27	48,160,691.04	(48,768,952.36)	39,173,619.59	-
12	37,108,639.17	36,447,567.75	(36,404,854.35)	37,065,925.78	-
13	34,825,062.37	12,154,784.05	(12,453,442.68)	35,123,721.00	-
14	30,637,386.24	9,193,210.59	(8,667,542.55)	30,111,718.20	-
15	36,996,301.74	14,922,914.69	(14,656,254.68)	36,729,641.73	-
16	36,027,018.63	7,749,064.03	(7,855,006.85)	36,132,961.45	-
17	34,987,569.78	9,177,638.32	(8,814,034.14)	34,623,965.60	-
18	36,705,346.98	11,478,427.00	(11,223,354.92)	36,450,274.90	-
19	37,423,745.55	12,805,500.89	(12,126,766.55)	36,745,011.21	-
20	35,439,438.11	8,879,104.08	(8,473,167.97)	35,033,502.00	-
21	31,769,937.56	7,545,682.62	(7,094,988.97)	31,317,243.90	-
22	38,469,952.50	17,337,109.60	(17,415,687.84)	37,548,530.75	-

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23	39,296,374.79	29,235,127.78	(28,058,482.35)	38,119,729.36	-
24	39,633,384.33	42,672,384.55	(40,829,694.34)	37,790,694.12	-
25	44,418,717.76	106,735,315.98	(99,803,851.09)	37,487,252.87	-
26	28,692,000.36	85,476,018.88	(94,726,707.07)	37,942,688.55	-
27	28,427,033.53	49,295,653.05	(55,549,497.32)	34,680,877.80	-
28	26,267,269.86	198,703,395.13	(21,625,090.47)	28,021,965.20	-
29	38,665,132.56	102,264,400.06	(100,454,093.50)	36,854,826.00	-
30	42,954,618.41	140,437,870.60	(136,651,967.51)	39,168,715.31	-
Total Payment	**1,090,320,354.29**				

Table 5.3-2 Initial Condition for Single-Settlement System

The initial condition calculated total generation cost using equation (37) was PHP 1,090,320,354.29, with an average price of PHP 5.592/kWh. It can be noted that the Fixed Spot is constant in the optimization while the BCQ adjustment are the changes in the Total Trading Amount (TTA) by netting out the BCQ in the settlement. The BCQ payments, on the other hand, are settled outside the market.

Assuming that the penalty cost is 50% of the contract price and using the optimization model in equation (34), Table 5.3-3 shows the results of the optimization.

Day	Total Gen Cost (PHP)	Fixed Spot (PHP)	BCQ Adjusments (PHP)	BCQ Payment (PHP)	Penalty (PHP)	% Improvement
1	36,631,475.62	14,126,875.91	(14,979,989.14)	36,932,844.41	551,744.43	-0.09%
2	36,346,171.56	3,820,814.12	(3,846,618.75)	36,371,974.58	1.61	0.00%
3	37,064,414.38	14,040,206.27	(13,672,098.75)	36,696,304.98	1.89	0.00%
4	32,278,716.38	42,030,491.89	(54,357,721.22)	37,530,617.38	7,075,328.33	-18.17%
5	2,144,534.92	81,087,908.71	(107,642,664.13)	37,814,637.88	10,144,652.45	-48.76%
6	35,495,200.14	20,267,996.63	(21,406,225.83)	34,890,555.80	1,742,873.54	-1.08%
7	30,189,771.72	12,851,838.50	(14,630,103.42)	30,586,157.60	1,381,879.05	-4.04%
8	27,143,751.47	50,687,513.25	(68,492,088.11)	36,358,857.13	8,589,469.21	-31.00%
9	25,530,815.71	52,145,607.96	(71,675,747.05)	38,029,164.30	7,031,790.50	-33.66%
10	17,784,607.54	63,906,364.61	(91,863,753.93)	37,679,466.50	8,062,530.36	-51.34%
11	28,796,403.33	48,160,691.04	(65,288,297.22)	39,173,619.59	6,750,389.92	-25.33%
12	31,694,479.23	36,447,567.75	(48,294,610.78)	37,065,925.78	6,475,596.49	-14.59%
13	34,602,452.66	12,154,784.05	(13,291,064.52)	35,123,721.00	615,012.12	-0.64%
14	30,637,391.46	9,193,210.59	(8,667,552.91)	30,111,718.20	15.58	0.00%
15	35,195,373.51	14,922,914.69	(18,700,218.91)	36,729,641.73	2,243,036.01	-4.87%
16	36,027,022.03	7,749,064.03	(7,855,006.85)	36,132,961.45	3.40	0.00%
17	34,987,571.95	9,177,638.32	(8,814,034.14)	34,623,965.60	2.17	0.00%
18	36,705,349.25	11,478,427.00	(11,223,354.92)	36,450,274.90	2.28	0.00%
19	37,412,416.91	12,805,500.89	(12,611,360.21)	36,745,011.21	473,265.02	-0.03%
20	35,439,440.14	8,879,104.08	(8,473,167.97)	35,033,502.00	2.03	0.00%

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21	31,564,994.03	7,545,682.62	(7,994,033.19)	31,317,243.90	694,100.69	-0.65%
22	37,717,812.93	18,337,109.60	(19,836,270.78)	37,548,530.75	1,668,443.33	-1.96%
23	36,753,759.17	29,235,127.78	(35,765,240.78)	38,119,729.36	5,164,142.81	-6.47%
24	31,931,490.29	42,672,384.55	(55,413,187.37)	37,790,694.12	6,881,598.99	-19.43%
25	16,402,834.24	106,735,315.98	(138,210,646.63)	37,487,252.87	10,390,912.01	-63.07%
26	4,150,385.28	85,476,018.88	(129,330,549.28)	37,942,688.55	10,062,227.13	-85.53%
27	9,936,219.28	49,295,653.05	(83,663,964.79)	34,680,877.80	9,623,653.22	-65.05%
28	21,050,582.76	19,870,395.13	(36,600,555.96)	28,021,965.20	9,758,778.39	-19.86%
29	5,990,882.27	102,264,400.06	(143,109,099.80)	36,854,826.00	9,980,756.01	-84.51%
30	1,784,079.32	140,437,870.60	(189,985,679.84)	39,168,715.31	12,163,173.24	-95.85%
Total Payment	**838,650,399.48**					**-23.08%**
Ave Gen Cost	**4,301.54**					

Table 5.3-3 Results for Single-Settlement System at 50% Penalty

Figure 5.3-3 shows the comparison of the new generation cost and original cost throughout the month.

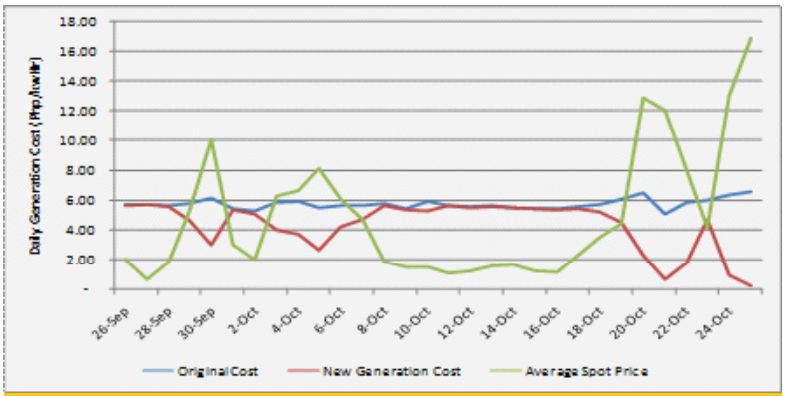

Figure 5.3-3 Single-Settlement Generation Cost Reduction

The total generation cost that was calculated using equation (37) resulted in PHP838,650,399.47, with an average price of PHP4.302/kWh. This is 23.08% cheaper than the original BCQ declarations at 50% penalty cost.

TWO-SETTLEMENT SYSTEM

Since the Philippine WESM is using the Two-Settlement System, the data processed in Section 5.3 were used using the Two-Settlement System derived in Section 3.2. The initial condition is summarized in the Table 5.4-1.

Day	Total Gen Cost (PHP)	Fixed Spot (PHP)	BCQ Adjusments (PHP)	BCQ Payment (PHP)	Penalty (PHP)
1	36,903,877.97	14,064,660.76	(14,093,627.21)	36,932,844.41	-
2	36,373,041.71	3,773,798.15	(3,772,731.02)	36,371,974.58	-
3	37,396,778.82	14,079,371.38	(13,378,897.53)	36,696,304.98	-
4	39,922,277.88	41,633,740.69	(39,242,080.19)	37,530,617.38	-

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5	42,990,155.79	80,841,890.75	(75,666,372.85)	37,814,637.88	-
6	35,987,658.82	19,997,068.15	(18,899,965.13)	34,890,555.80	-
7	31,422,443.57	12,613,727.84	(11,777,441.87)	30,586,157.60	-
8	39,907,845.09	50,099,938.20	(46,550,950.24)	36,358,857.13	-
9	40,074,807.38	51,171,139.29	(49,125,496.21)	38,029,164.30	-
10	36,653,334.33	62,870,869.70	(63,897,001.87)	37,679,466.50	-
11	38,540,810.28	47,703,665.81	(48,336,475.13)	39,173,619.59	-
12	37,676,919.09	36,475,278.54	(35,864,285.23)	37,065,925.78	-
13	35,166,077.05	12,207,409.75	(12,165,053.71)	35,123,721.00	-
14	30,848,165.20	9,234,610.45	(8,498,163.45)	30,111,718.20	-
15	39,774,489.66	15,155,603.03	(12,110,755.10)	36,729,641.73	-
16	36,265,212.98	7,773,125.63	(7,640,874.10)	36,132,961.45	-
17	35,241,241.20	9,199,436.83	(8,582,161.23)	34,623,965.60	-
18	37,027,006.90	11,509,157.72	(10,932,425.72)	36,450,274.90	-
19	37,755,218.05	12,800,456.14	(11,790,249.30)	36,745,011.21	-
20	35,643,462.33	8,850,736.81	(8,240,776.47)	35,033,502.00	-
21	32,097,157.38	7,628,495.55	(6,850,582.07)	31,319,243.90	-
22	38,861,177.56	18,307,778.98	(16,995,132.16)	37,548,530.75	-
23	40,433,778.35	29,310,537.78	(26,996,488.79)	38,119,729.36	-
24	42,800,802.72	41,973,660.45	(36,963,551.85)	37,790,694.12	-
25	46,221,353.87	106,777,077.57	(98,042,976.57)	37,487,252.87	-
26	30,619,945.48	85,599,199.20	(92,921,942.27)	37,942,688.55	-
27	31,557,589.55	51,142,360.50	(54,265,648.75)	34,680,877.80	-
28	26,768,623.91	19,903,514.60	(21,156,855.89)	28,021,965.20	-
29	40,497,092.03	102,315,000.68	(98,672,734.65)	36,854,826.00	-
30	46,156,098.79	141,174,666.91	(134,187,283.43)	39,168,715.31	-
Total Payment	**1,117,584,443.75**				
Ave Gen Cost	**5,732.23**				

Table 5.4-1 Results for Single-Settlement System at 50% Penalty

The initial calculated total generation cost using the equation (35) was PHP 1,117,584,443.75, with an average price of PHP 5.732/kWh. Note that the difference between the two systems upon calculation of the initial generation cost was only 2.5%. Primarily, this can be attributed to the calculation methods for the optimization model by comparing equations (34) and (40).

In addition, assuming the same penalty cost of 50% of the contract quantity, using the optimization model in equation (40), equation (41) resulted in an average price of PHP 4,503.68/kW has shown in Table 5.4-2.

Day	Total Gen Cost (PHP)	Fixed Spot (PHP)	BCQ Adjusments (PHP)	BCQ Payment (PHP)	Penalty (PHP)	% Improvement
1	34,856,553.06	14,064,660.76	(11,655,912.89)	27,962,765.73	4,485,039.46	-5.55%
2	32,055,608.62	3,773,798.15	(2,946,295.07)	26,084,236.23	5,143,869.31	-11.87%
3	35,433,826.37	14,079,371.38	(12,070,421.87)	30,153,448.18	3,271,428.69	-5.25%
4	34,990,495.86	41,633,740.69	(50,310,330.26)	38,751,311.39	4,915,774.04	-12.35%
5	25,143,351.59	80,841,890.75	(105,896,366.17)	42,452,055.16	7,745,771.85	-41.51%
6	35,385,697.76	19,997,068.15	(16,886,764.96)	29,660,232.15	2,615,162.43	-1.67%
7	29,482,522.13	12,613,727.84	(12,656,501.25)	26,903,219.31	2,622,076.22	-6.17%
8	31,513,807.08	50,099,938.20	(65,030,089.20)	40,225,871.15	6,218,086.93	-21.03%
9	29,004,379.84	51,171,139.29	(67,156,452.74)	38,355,513.07	6,634,180.23	-27.62%
10	20,504,470.45	62,870,869.70	(89,720,148.16)	40,960,938.88	6,392,810.03	-44.06%
11	31,303,580.32	47,703,665.81	(62,078,247.54)	39,146,799.15	6,531,362.90	-18.78%
12	34,058,102.83	36,475,278.54	(45,149,978.03)	37,586,839.19	5,145,963.13	-9.60%
13	33,156,222.40	12,207,409.75	(9,900,837.96)	26,575,580.21	4,274,070.40	-5.72%
14	29,749,311.43	9,234,610.45	(8,033,883.71)	26,985,415.71	1,563,168.98	-3.56%
15	35,910,769.57	15,155,603.03	(12,035,680.19)	26,772,743.98	6,018,102.75	-9.71%
16	32,724,642.34	7,773,125.63	(6,385,678.50)	26,541,428.44	4,795,766.77	-9.76%
17	32,591,619.52	9,199,436.83	(6,996,366.39)	26,153,132.27	4,235,416.81	-7.52%
18	34,313,246.03	11,509,157.72	(8,527,048.82)	26,211,999.04	5,119,138.09	-7.33%
19	35,206,092.59	12,800,456.14	(9,239,429.60)	26,545,120.80	5,099,945.26	-6.75%
20	32,557,920.92	8,850,736.81	(6,867,941.86)	26,116,748.84	4,458,377.13	-8.66%
21	30,243,015.50	7,628,495.55	(6,685,613.66)	26,701,190.26	2,598,943.35	-5.78%
22	36,263,638.72	18,307,778.98	(15,662,749.20)	28,539,713.09	5,078,895.85	-6.68%
23	39,342,926.82	29,310,537.78	(29,146,667.04)	34,946,554.85	4,232,501.22	-2.70%
24	37,663,769.54	41,973,660.45	(47,096,330.21)	38,116,863.84	4,669,575.47	-12.00%
25	21,997,200.40	106,777,077.57	(135,542,713.86)	43,893,441.89	6,869,394.79	-52.41%
26	9,027,038.70	85,599,199.20	(127,159,241.71)	43,238,525.09	7,348,556.12	-70.52%
27	18,880,090.59	51,142,360.50	(78,872,469.44)	40,647,250.02	5,962,949.50	-40.17%
28	26,365,272.46	19,903,514.60	(29,669,634.66)	32,392,587.64	3,738,804.89	-1.51%
29	11,728,161.05	102,315,000.68	(141,482,119.75)	43,125,237.09	7,770,043.03	-71.04%
30	6,606,824.41	141,174,666.91	(186,206,643.76)	43,305,165.09	8,333,636.17	-85.69%
Total Payment	**878,060,158.90**					**-21.43%**
Ave Gen Cost	**4,503.68**					

Table 5.4-2 Results of the Two-Settlement System with 50% Penalty

Figure 5.4-1 shows the comparison of the new generation cost and original cost throughout the month, while Figure 5.4-2 shows the comparison between the Single-Settlement System and the Two-Settlement System.

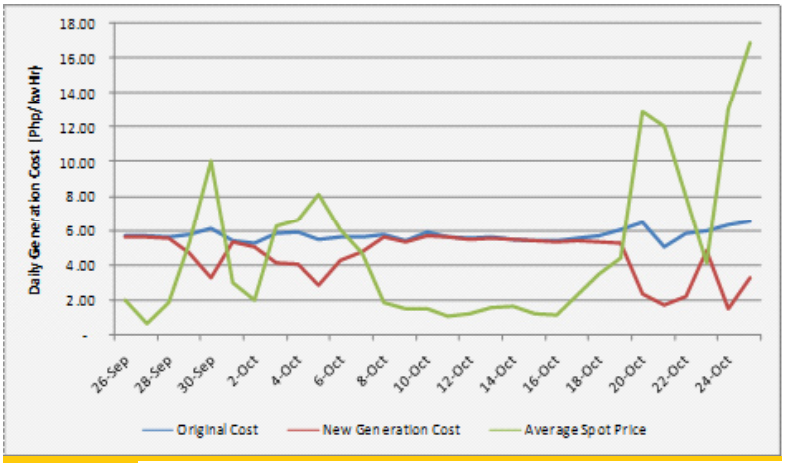

Figure 5.4-1 Two-Settlement Generation Cost Reduction

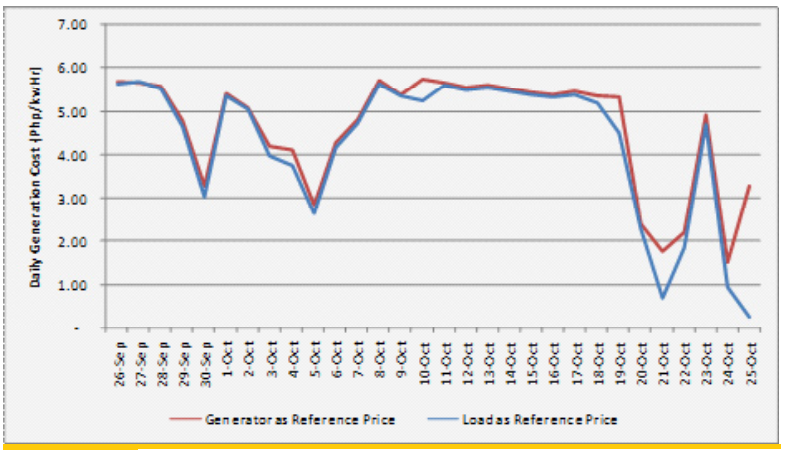

Figure 5.4-2 Single vs. Two-Settlement Generation Cost Reduction

It can be noticed that the results of the Two-Settlement System is only 1.65% away from the Single-Settlement System.This can be attributed to the difference in the objective function by comparing equations (34) and (40). Also, the application of the penalty factor contributed to the difference because in the Two-Settlement System, the penalty cost is used on top of the contract quantity, while in the Single-Settlement System, the penalty cost is used in lieu of the contract price whenever there are adjustments.

Note that the Single-Settlement System is very similar to the reference paper's Optimization model. This proves that modifying the reference paper's optimization model, as described in the Two-Settlement System in Section 3.2, from which the Philippine WESM settlement can be applied, is justified.

MATCH POINT PENALTY COST

The modified optimization model using the Two-Settlement Sytem in Section 5.4 has now been proven. The only problem now is how to set the penalty cost. Note that increasing the penalty cost percentage shall entail a reduction in the distribution company's savings as the the generation companies' sales increases. Thus, there is a need to find the equilibrium point wherein the penalty cost percentage is beneficial to both parties by incrementally changing in the penalty cost percentage by 1% from 0% up to 100%.

The results of the simulation using the objective function in equation (34) that was subjected to the contraints as described in Table 5.3-1 is shown in Figure 5.5-1. It can be observed that the generation cost increases as the penalty cost increases. Also, notice that even if the penalty cost is equal to the contract price, or somewhat similar to the take or pay provision, the DisCo still had considerable savings of around 12.08%. This condition was stipulated when the spot market prices were very high, in which the DisCo wanted to maximize its bilateral contracts. Another point-of-view is that since the penalty cost is on top of the contract price, the 100% penalty cost percentage means that the DisCo is willing to pay twice their contract price for any additional energy sourced from its bilateral contract.

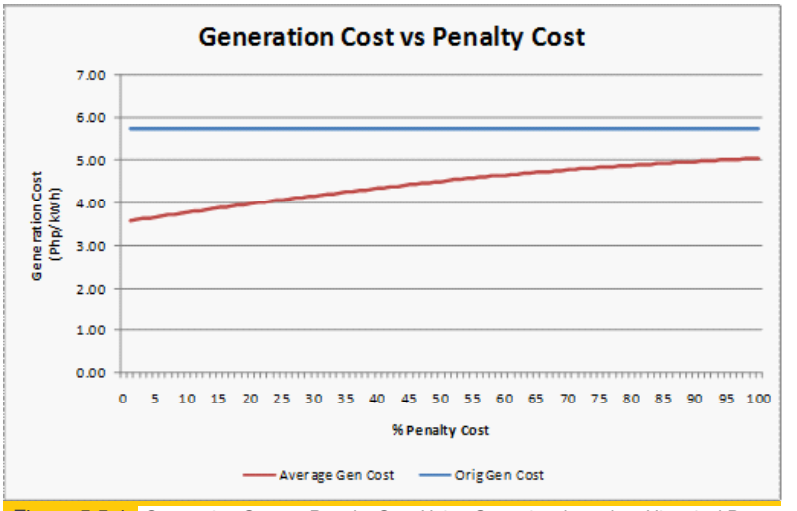

Figure 5.5-1 Generation Cost vs Penalty Cost Using Contraints based on Historical Data

However, it is important to note that currently in the WESM, adjusting the bilateral quantities are within the control of the GenCos. The DisCos can only nominate its bilateral contracts. Also, no penalties are imposed when adjustments are introduced provided that the changes are acknowledged by the Market Operator one day (D+1) after the conclusion of the trading date. Thus, using the current practice without the penalties, the DisCo can maximize the savings as much as 37.79%, or reduce the generation cost to PHP 3.565/kWh from PHP 5.732/kWh.

It can be noted that while the savings of the DisCo decreases as the penalty cost percentage increases, the GenCos bilateral contract sales, with respect to the DisCos, increases. Thus, the DisCo wanted to a have the lowest possible penalty cost, while the GenCos wanted to have a higher penalty cost to secure their income. An equilibrium point was determined by increasing the penalty cost percentage by 1% and then interpolating between the nearest percentage as shown in the Table 5.5-1.

Percentage	Average Gen Cost (PHP/MW)	% Savings	% Increase in BC Paymentt
1	3,586.70	37.43%	-7.25%
2	3,610.28	37.02%	-6.89%
3	3,633.49	36.61%	-6.55%
4	3,656.32	36.21%	-6.24%
5	3,678.92	35.82%	-5.93%
6	3,701.40	35.43%	-5.59%
7	3,723.69	35.04%	-5.31%
8	3,745.75	34.65%	-4.97%
9	3,767.66	34.27%	-4.69%
10	3,789.27	33.90%	-4.30%
11	3,810.56	33.52%	-4.02%
12	3,831.67	33.16%	-3.91%
13	3,852.34	32.80%	-3.66%
14	3,873.24	32.43%	-3.36%
15	3,893.52	32.08%	-3.08%
16	3,913.46	31.73%	-2.86%
17	3,933.15	31.39%	-2.94%
18	3,952.64	31.05%	-2.59%
19	3,972.02	30.71%	-2.36%
20	3,991.26	30.37%	-2.01%
21	4,010.41	30.04%	-1.71%
22	4,029.47	29.71%	-1.34%
23	4,048.48	29.37%	-0.95%
24	4,067.33	29.04%	-0.68%
25	4,086.09	28.72%	-0.35%
26	4,105.04	28.39%	-0.10%
27	4,123.60	28.06%	0.31%
28	4,142.00	27.74%	0.68%
29	4,160.39	27.42%	0.88%
30	4,178.65	27.10%	1.09%
31	4,196.81	26.79%	1.29%
32	4,214.87	26.47%	1.45%
33	4,232.88	26.16%	1.78%
34	4,250.84	25.84%	2.04%
35	4,268.70	25.53%	2.37%
36	4,286.31	25.22%	2.75%
37	4,303.99	24.92%	3.05%
38	4,321.30	24.61%	3.36%
39	4,338.81	24.31%	3.68%

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40	4,356.29	24.00%	3.94%
41	4,373.66	23.70%	4.25%
42	4,390.89	23.40%	4.49%
43	4,407.00	23.12%	4.85%
44	4,424.29	22.82%	5.14%
45	4,440.97	22.53%	5.76%
46	4,457.60	22.24%	6.25%
47	4,474.22	21.95%	6.45%
48	4,490.23	21.67%	6.78%
49	4,506.03	21.39%	7.16%
50	4,521.75	21.12%	7.38%
51	4,537.25	20.85%	7.65%
52	4,552.65	20.58%	8.02%
53	4,567.56	20.32%	8.17%
54	4,582.13	20.06%	8.33%
55	4,596.41	19.81%	8.55%
56	4,610.50	19.57%	8.80%
57	4,624.44	19.33%	9.02%
58	4,638.21	19.09%	9.23%
59	4,651.62	18.85%	9.51%
60	4,664.67	18.62%	9.80%
61	4,677.57	18.40%	10.06%
62	4,690.31	18.18%	10.35%
63	4,702.91	17.96%	10.56%
64	4,715.44	17.74%	10.78%
65	4,727.85	17.52%	10.91%
66	4,740.05	17.31%	11.18%
67	4,752.14	17.10%	11.38%
68	4,764.05	16.89%	11.71%
69	4,775.73	16.69%	11.94%
70	4,787.24	16.49%	12.12%
71	4,798.61	16.29%	12.26%
72	4,809.84	16.09%	12.42%
73	4,820.79	15.90%	12.43%
74	4,831.55	15.71%	12.56%
75	4,842.10	15.53%	12.79%
76	4,852.47	15.35%	12.96%
77	4,861.83	15.18%	13.11%
78	4,871.92	15.01%	13.13%
79	4,881.75	14.84%	13.30%
80	4,891.19	14.67%	13.54%

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81	4,900.43	14.51%	13.68%
82	4,909.62	14.35%	13.82%
83	4,918.65	14.19%	13.95%
84	4,927.61	14.04%	14.08%
85	4,936.52	13.88%	14.14%
86	4,945.28	13.73%	14.21%
87	4,953.91	13.58%	14.21%
88	4,962.40	13.43%	14.28%
89	4,970.79	13.28%	14.35%
90	4,979.12	13.14%	14.44%
91	4,987.34	12.99%	14.56%
92	4,995.49	12.85%	14.69%
93	5,003.50	12.71%	14.76%
94	5,011.28	12.58%	14.88%
95	5,018.64	12.45%	14.98%
96	5,025.46	12.33%	14.99%
97	5,031.83	12.22%	15.12%
98	5,038.03	12.11%	15.12%
99	5,044.15	12.00%	15.20%
100	5,050.22	11.90%	15.27%

Table 5.5-1 Determination of the Match Point Penalty Cost Percentage

In graphical form, the DisCo's savings matches the GenCo's higher contract sales as shown in Figure 5.5-2.

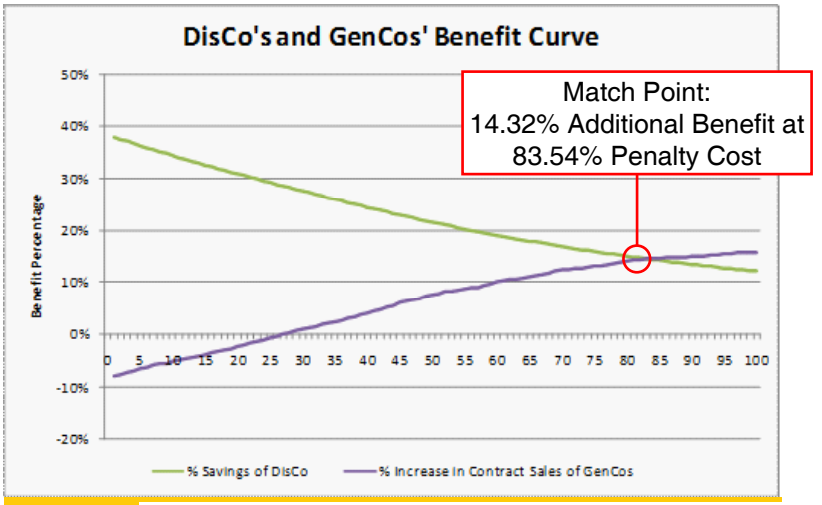

Figure 5.5-2 Benefit Curve of the DisCo and GenCos Using Contraints Based on Historical Data

The match point is at 83.54% penalty cost, which is relatively high since this shall be paid on top of the contract price with both parties benefiting at 14.32%. Thus, it can be recommended that this value should be the basis of the ceiling of the penalty cost percentage. Meanwhile, the floor penalty cost percentage should be at the break-even point in the GenCo's sales at

26.23%, with 28.64% savings on the generation cost by the DisCo. Thus, the DisCos and GenCos should agree and choose the penalty cost percentage from 26.23% to 83.54% considering the DisCo's savings from 14.32% to 28.64%. Any value between that range will not entail Generation Contract Sales Reduction, but will ensure savings for the DisCo. Moreover, the GenCo's sales was determined with respect to the specific DisCo under study.

It is important to note however, that the adjustments in the contract quantites between the DisCo and GenCo might affect the contract quantities of the GenCo with other DisCos and its purchases and/or sales in the spot market. Thus, the GenCos will definitely push for the maximum penalty cost.

FREEING THE HOURLY AND DAILY BCQ CONSTRAINTS

Since the hourly and daily BCQ contraints are based only on the historical BCQ declarations, data on this might induce inconsistency or inaccuracy in the actual practice. Thus, another simulation was established to see a more optimal solution with free hourly and daily BCQ contraints. Note that by using historical data, some GenCos have their BCQ declarations fixed at a certain value (based on Table 5.3-1, Gen 2,10 and 11 were fixed at 30MW,15 MW and 15MW, respectively). In this simulation, the limitations on the hourly and daily BCQ contraints are freed up based on the capacity and availability of the contracted GenCos. Table 5.6-1 shows the new bilateral contract data that will be used as constraints on the same set of data.

Generator	BC Price (PHP/MW)	Daily		Hourly	
		Min (MW)	Max (MW)	Min (MW)	Max (MW)
Gen 1	4,715.80	0.00	2,356.38	0.00	155.85
Gen 2	4,855.40	0.00	720.00	0.00	60.00
Gen 3	9,431.60	0.00	48.20	0.00	12.98
Gen 4	9,431.60	0.00	48.20	0.00	12.35
Gen 5	6,664.00	0.00	2,355.00	0.00	105.00
Gen 6	9,826.60	0.00	343.00	0.00	52.00
Gen 7	4,715.80	0.00	435.78	0.00	46.00
Gen 8	4,715.80	0.00	435.78	0.00	50.68
Gen 9	4,715.80	0.00	284.00	0.00	23.00
Gen 10	4,855.40	0.00	360.00	0.00	30.00
Gen 11	4,855.40	0.00	360.00	0.00	30.00
Gen 12	7,346.40	0.00	360.00	0.00	16.00

Table 5.6-1 Modified Bilateral Contract Data of the Distribution Company

The results of the simulation using the objective function in equation (40) that was subjected to the contraints as described in Table 5.6-1is shown in Figure 5.6-1.

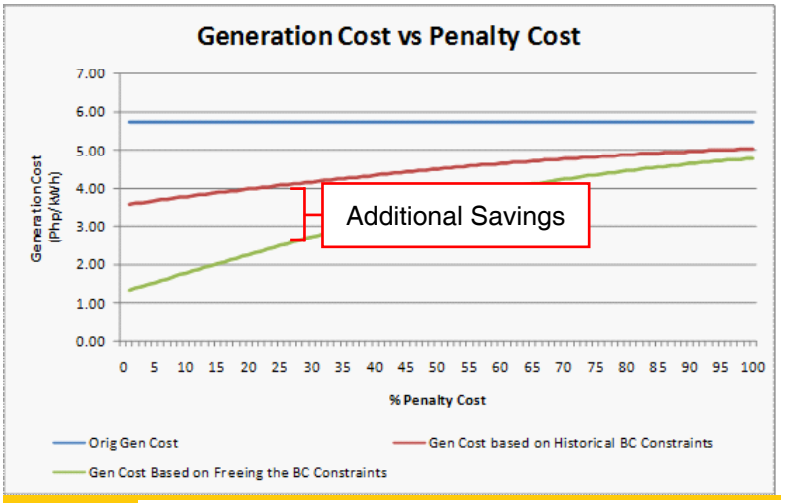

Figure 5.6-1 Generation Costs vs Penalty Costwith Freeing Up of BC Constraints

Upon freeing the contraints, the DisCo will have on average an additional savings of 42.85%. Similarly, the match point is determined by a 1% increment on the penalty cost as shown in Table 5.6-2.

Percentage	Average Gen Cost (PHP/MW)	% Savings	% Increase in BC Paymentt
1	1,341.32	76.60%	-52.30%
2	1,391.83	75.72%	-51.38%
3	1,442.15	74.84%	-50.55%
4	1,492.35	73.97%	-49.71%
5	1,542.37	73.09%	-48.91%
6	1,592.29	72.22%	-48.11%
7	1,642.07	71.35%	-47.28%
8	1,691.78	70.49%	-46.43%
9	1,741.42	69.62%	-45.62%
10	1,790.90	68.76%	-44.45%
11	1,840.18	67.90%	-43.58%
12	1,889.34	67.04%	-42.85%
13	1,938.14	66.19%	-42.02%
14	1,987.24	65.33%	-41.06%
15	2,035.69	64.49%	-40.14%
16	2,083.85	63.65%	-39.26%
17	2,131.80	62.81%	-38.76%
18	2,179.51	61.98%	-37.74%
19	2,227.08	61.15%	-36.94%
20	2,274.43	60.32%	-35.98%
21	2,321.65	59.50%	-35.12%
22	2,368.76	58.68%	-34.25%

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23	2,415.81	57.86%	-33.31%
24	2,462.68	57.04%	-32.46%
25	2,509.38	56.22%	-31.48%
26	2,556.11	55.41%	-30.59%
27	2,602.41	54.60%	-29.59%
28	2,648.45	53.80%	-28.55%
29	2,694.44	52.99%	-27.81%
30	2,740.27	52.20%	-26.92%
31	2,785.84	51.40%	-26.17%
32	2,831.27	50.61%	-25.47%
33	2,876.61	49.82%	-24.59%
34	2,921.89	49.03%	-23.82%
35	2,967.06	48.24%	-22.95%
36	3,011.88	47.46%	-22.02%
37	3,056.67	46.68%	-21.09%
38	3,100.87	45.90%	-19.99%
39	3,145.10	45.13%	-19.10%
40	3,189.04	44.37%	-18.06%
41	3,232.72	43.60%	-17.14%
42	3,276.15	42.85%	-16.38%
43	3,318.36	42.11%	-15.41%
44	3,361.53	41.36%	-14.25%
45	3,403.59	40.62%	-12.80%
46	3,445.10	39.90%	-11.59%
47	3,486.24	39.18%	-10.63%
48	3,526.43	38.48%	-9.71%
49	3,566.13	37.79%	-8.71%
50	3,605.45	37.10%	-7.66%
51	3,644.14	36.43%	-6.83%
52	3,682.57	35.76%	-5.77%
53	3,720.18	35.10%	-4.90%
54	3,757.03	34.46%	-4.00%
55	3,793.28	33.83%	-3.28%
56	3,828.80	33.21%	-2.21%
57	3,863.82	32.59%	-1.46%
58	3,898.33	31.99%	-0.66%
59	3,932.20	31.40%	0.28%
60	3,964.94	30.83%	1.64%
61	3,996.59	30.28%	2.74%
62	4,027.27	29.74%	3.75%
63	4,057.32	29.22%	4.49%

(continues to next page)

64	4,086.73	28.71%	5.46%
65	4,115.45	28.21%	6.26%
66	4,143.21	27.72%	7.17%
67	4,170.28	27.25%	8.02%
68	4,196.39	26.79%	9.00%
69	4,221.73	26.35%	9.68%
70	4,246.46	25.92%	10.38%
71	4,270.18	25.51%	11.22%
72	4,293.45	25.10%	11.59%
73	4,316.37	24.70%	11.81%
74	4,338.96	24.31%	12.22%
75	4,361.13	23.92%	12.72%
76	4,382.94	23.54%	13.14%
77	4,403.58	23.18%	13.58%
78	4,424.73	22.81%	13.86%
79	4,445.34	22.45%	14.23%
80	4,465.40	22.10%	14.66%
81	4,485.03	21.76%	14.98%
82	4,504.39	21.42%	15.29%
83	4,523.42	21.09%	15.62%
84	4,542.33	20.76%	15.94%
85	4,561.05	20.43%	16.19%
86	4,579.26	20.11%	16.52%
87	4,597.11	19.80%	16.64%
88	4,614.70	19.50%	16.90%
89	4,632.13	19.19%	17.15%
90	4,649.35	18.89%	17.41%
91	4,666.32	18.60%	17.68%
92	4,682.90	18.31%	17.86%
93	4,699.13	18.02%	18.08%
94	4,714.86	17.75%	18.40%
95	4,729.59	17.49%	18.66%
96	4,742.97	17.26%	18.86%
97	4,754.62	17.05%	19.14%
98	4,765.68	16.86%	19.18%
99	4,776.56	16.67%	19.30%
100	4,787.37	16.48%	19.45%

Table 5.6-2 Determination of the Match Point Penalty Cost Percentage on Free Constraints

However, freeing up the constraints will expose to-be GenCos to the volatility of the spot market, wherein the benefits are optimized for the DisCo. Thus, a match point should be considered such that the GenCos will not lose its bilateral contract sales. Figure 5.6-2 below shows the match point during the freeing up of the constraints.

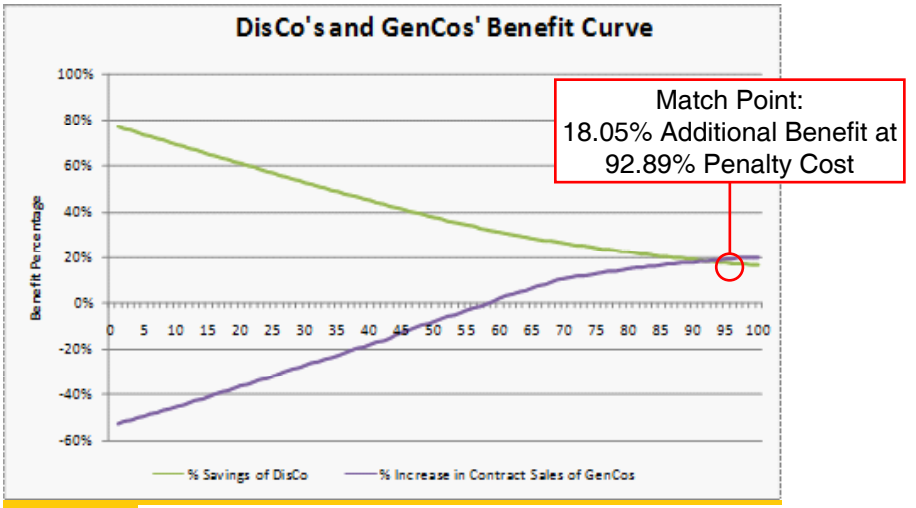

Figure 5.6-2 Benefit Curve of the DisCo and GenCos with Freeing Up of BC Constraints

The match point is at 92.89% penalty cost, which is relatively higher considering the historical constraints because of the additional room for more optimal schedules.However, although the penalty cost is higher, the savings is also higher at 18.05% against 14.32%. However, it can be observed that the break-even point for GenCos is at 58.70% penalty cost. This is because the risk of the volatility of the spot market price is transferred to the GenCos. Thus, the DisCos and GenCos should agree and choose the penalty cost percentage from a tighter range of 58.70% to 92.89% so that there will be no adverse effect on the GenCo's contract sales.

USING THE TWO-SETTLEMENT SYSTEM MODEL TO OTHER DATA

To further test the effectivity and accuracy of the model, the data was modified by introducing a random percentage from 95% to 105% to the metered quantities and initial bilateral contract quantities. In doing so, the same procedure was conducted as discussed in Sections 5.5 and 5.6. The results of which are shown in Figures5.7-1 and 5.7-2.

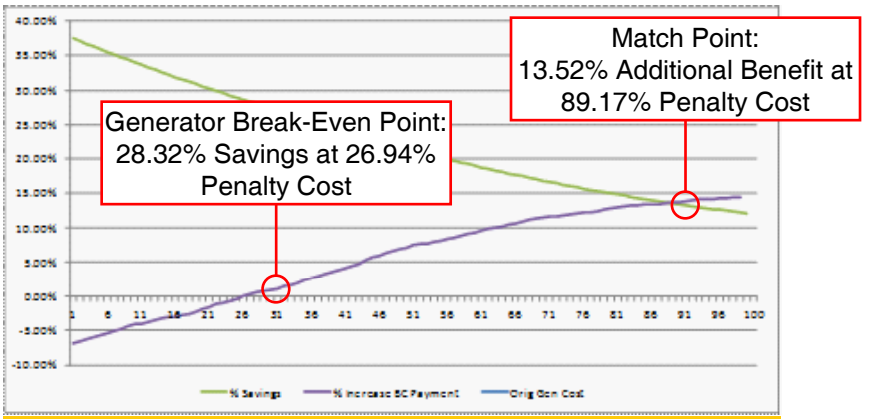

Figure 5.7-1 Benefit Curve of the DisCo and GenCos with Freeing Up of BC Constraints

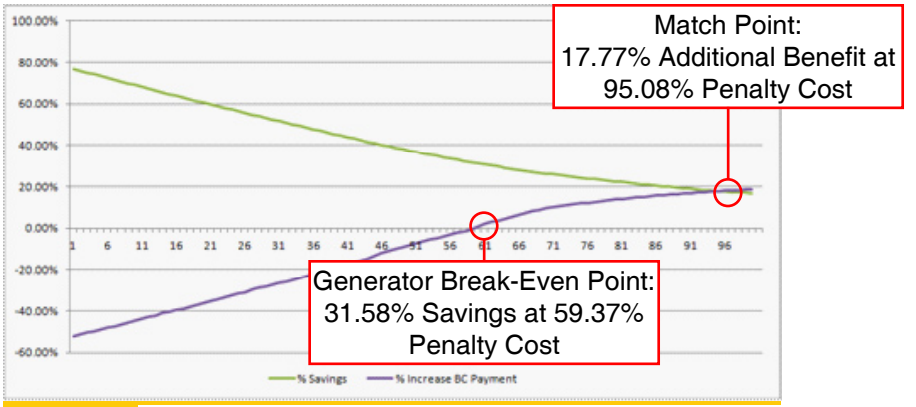

Figure 5.7-2 Benefit Curve of the DisCo and GenCos with FreeingUp of BC ConstraintsBased on Modified Historical Data

Table 5.7-1 summarizes the difference between the results in Sections 5.5 and 5.6 with Section 5.7.

Scenario	Critical Points	Penalty Cost Percentage			DisCo's Savings			GenCo's Increase in BC Sales		
		Orig Data	Modified Data	Abs(Diff)	Orig Data	Modified Data	Abs(Diff)	Orig Data	Modified Data	Abs(Diff)
Original Constraints	Break-Even	26.23%	26.94%	2.71%	28.64%	28.32%	1.12%	0.00%	0.00%	-
	Match Point	83.54%	89.17%	6.74%	14.32%	13.52%	5.59%	14.32%	13.52%	5.59%
Free Constraints	Break-Even	58.70%	59.37%	1.14%	31.99%	31.58%	1.28%	0.00%	0.00%	
		92.89%	95.08%	2.36%	18.05%	17.77%	1.55%	18.05%	17.77%	1.55%
		Average Difference		3.24%	Average Difference		2.38%	Average Difference		3.57%

Table 5.7-1 Summary of Results Using Modified Data

It can be noticed that the difference between the results only accounts for around 3%, which is lower than the random percentage variable of 5%. Thus, the model can be concluded as consistent with different data scenarios.

CONCLUSION

The bulk of the cost of electricity is dependent on the generation cost, thus, its reduction will result in lower electricity cost that will ultimately be passed on to consumers. Ideally, with the operation of the electricity market, the Distribution Companies shall enter into several bilateral contracts to mitigate the risk of high spot market prices during tight supply-demand conditions. However, the energy purchases of the Distribution Companies, be it through bilateral contracts or spot market transactions, are predominantly sub-optimal. In this study, a more optimal solution is proposed for the Distribution Companies in allocating their purchases of energy between bilateral contract and spot market (Test Case 5.1 – 5.7).

In this study, the reference paper's optimization model was successfully replicated using its data ensuring the correctness of the basis of the formulation of the Single-Settlement System and Two-Settlement System(Test Case 5.1). Also, using the available data, the reference paper's optimization model may be used for optimization, but this will not reflect the current settlement system of the WESM (Test 5.2).

Extending further using the historical data and simplifying the reference paper's optimization model, the Single-Settlement System Model was successfully implemented (Test Case 5.3) yielding savings for the DisCo.

By integrating the WESM's calculation of the Total Trading Amount resulting in a Two-Settlement System Model, the model produced results that are almost similar to the Single-Settlement System. This proves that the translation from single to two was successful and accurate (Test Case 5.4).

In determining the penalty cost percentage, the DisCo and GenCo are recommended to choose the in the region of negotiation. This is from the break-even point on the contract sales of the GenCo up to the match point of savings of the DisCo and the GenCo's increase in contract sales (Test Case 5.5).

Further tests show that bilateral contract constraints limit the optimization, thus, freeing the bilateral contract constraints will generate more savings for the distribution companies, but with a narrower region of negotiation (Test Case 5.6). Also, the Two-Settlement System model can be concluded as consistent with different data scenarios as other data sets yielded similar results (Test Case 5.7).

Overall, the results showed that the modified optimization model generated more cost-effective allocation spot market and bilateral contract quantities for the DisCo after quantity adjustments and applying the corresponding penalties.

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