

Attachment 2

Market Simulation – Luzon Grid

- Full Nodal Pricing and Customer Zonal Pricing
 - Market Surplus
-

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1.0 Executive Summary

The simulation performed aims to quantify potential cross subsidies in considering zonal pricing in comparison to applying full nodal pricing for customers. It also quantifies congestion rentals (congestion surplus) arising from the operation of the market.

The simulation utilized the Luzon Demonstration Market System (LDMS) which is spreadsheet based linear optimization software. The LDMS incorporates the algorithm prescribed in the WESM Price Determination Methodology, however, it inherently has optimizer and network modeling limitations. Although the LDMS incorporates the necessary linear optimization constraints it does not incorporate soft constraint (no constraint violation coefficients) and utilizes a limited capability 3rd party linear optimization solver (What's Best). The LDMS, also incorporates a simplified 30 bus system representing the Luzon Grid. Although, the LDMS, has certain linear optimization limitations, recognition of these limitations enable the accurate and reasonable translation of simulation output.

The simulation considered two months (May 2004 and September 2003) representing dry and wet seasons to capture the dispatch capability and behavior of generators. Demand profiles were based on the SO Daily Operations Report (DOR) while a single block generator offer was applied based on variable costs of the generating plants. The simulation also disregarded reserve offers and hence no co-optimization of reserve was performed.

Using these conditions, hourly dispatch and nodal pricing ex-ante market was calculated. The dry season averages was then applied also for the months of March, April, May, June and the wet season averages was applied for the rest of the months (July, August, September, October, November, December, January and February) to provide an estimate for a one year simulation horizon.

Customer Zonal Pricing vs. Full Nodal Pricing

For the dry season, the average monthly energy consumption is 3,574 GWh which amounted to customer payment of P 9,199 Million. The amount subsidized to customers with higher nodal prices is P 684 Million or 7.44%, this is the total amount derived from hourly difference between zonal price and nodal price. While for the wet season, monthly energy consumption is 3310 GWh which amounted to customer payment of P8,688 Million and the subsidy amounted to P559 Million or 6.43% of the customer payment. The annual

subsidy or the amount saved by customers with higher nodal prices is P7,207 Million.

For customer zonal pricing, Luzon grid was divided into three pricing zones, these include North Luzon, Metro Manila, and South Luzon to capture the inherent demand characteristics of these areas and its corresponding impact to zonal pricing. For Metro Manila, the simulation showed zonal prices range from 2.00 to 4.30 P/KWh and the nodal prices range from 1.80 to 5.20 P/KWh. For North Luzon zonal prices range from 1.80 to 4.00 P/KWh and the nodal prices range from 1.60 to 5.00 P/KWh. And for South Luzon, 1.80 to 4.00 P/KWh and 1.20 to 5.00 P/KWh for zonal and nodal prices, respectively.

Market Surplus (Line Rentals)

Average monthly surplus for the dry season amounted to 1,264 Million pesos, while for the wet season; the average monthly surplus amounted to 1,231 Million pesos.

During the dry season , surplus due to losses was calculated to amount to 336 Million pesos while for the wet season, loss surplus amounted to 263 Million Pesos. Correspondingly, dry season congestion surplus amounted to 928 Million pesos while for the wet season, it amounted to 968 Million pesos.

Translated on an annual average, line rentals due to losses amounted to 3,451 Million pesos while rentals due to congestion amounted to 11,425 Million pesos.

2.0 About this Document

This document provides the simulation results conducted by the Market Operations Group in compliance to the ERC directive on the Price Determination Methodology (PDM). The simulation uses assumptions on which the Market Operations make no representation or warranty. As such, the MO shall have, and accept, no liability for any statements, opinions, information or matters (expressed or implied) arising out of, contained in or derived from this document. It should be noted that the results indicated herein are indicative since real market based inputs are subject to generator and customer bidding strategies.

3.0 Background

Last June 26, 2003, the Department of Energy (DOE) through the counsel of its authorized agent, National Transmission Corporation – Market Operations (TRANSCO-MO) filed the Price Determination Methodology (PDM) for the Philippine Wholesale Electricity Spot Market (WESM) to Energy Regulatory Commission (ERC) for approval. To facilitate the approval of the PDM, TRANSCO-MO submitted additional documents as per ERC order dated July 23, 2003 and a public consultation was held last February 12, 2003 which was attended by industry participants. On March 17, 2004, ERC issued its decision on the PDM application granting conditional approval and directed the TRANSCO-MO to submit additional documents including market simulations.

4.0 Objective

- 4.1 Quantify the potential cross subsidies that would be created by the adoption of the Customer Pricing Zones in comparison to applying full nodal pricing for both generators and customers.
- 4.2 Provide information as to the likely magnitude of congestion surplus from line rental revenues.

5.0 General Assumptions and Input Data

The market simulation uses historical data that includes system demand, line and generator outages and hydro limitations. In addition, some input data were assumed which includes generator offers and security screening. These data provides the necessary system condition in the analysis. Equipment capacity and other parameters were based on planning data. The Market Network Model (MNM) used in the simulation is the simplified 30 Bus Luzon Grid system.

The historical data for May 2004 and September 2003 were used to represent dry season and wet season scenarios, respectively. May 2004 registered the highest demand for the year 2004. This month is also one of the hottest in the dry season and it is assumed that most of the hydroelectric plants during this season experience limitations in the plant reservoir's level.

On the other hand, September 2003 was used to represent the typical wet season scenario, wherein, hydro generators have sufficient water reservoir level.

5.1 System Demand

The hourly system demand used in the market simulation has a peak and off-peak value of 6,264 MW and 3,564 MW, respectively, for the month of May, while 5885 MW and 2863 MW, respectively, for the month of September.

5.2 Load Profile

The Luzon grid typically has four sets of load profile representing the days of Sunday, Monday, Tuesday to Friday and Saturday. Three peak periods are normally observed occurring at 11 am, 2 pm and 7 pm for the weekdays and Saturday while the off-peak periods are between 4 and 6 am. For Sunday, a single peak period at 7 pm is normally observed while the off-peak are at 5 to 7 am. Appendix 1 shows the typical load profile for the Luzon Grid.

5.3 Line Outages and Generator Limitations

Line outages and generator capacity limitations applied in the market simulation were based on the Daily Operational Highlights (DOH) provided by the System Operations (SO). In the simulation, economic shutdown of generators is disregarded since the dispatch schedule will be dictated by the offered prices of the generators. On the other hand, the generator capacity will be based on the SO Daily operations capability of the different plants for the months of May 2004 and September 2003 to reflect a realistic generator output capability.

5.4 Hydro limitations

For the month of May, among the eight hydroelectric generators/complexes in Luzon, Ambuklao, Angat, Casecnan and San Roque are not capable of producing energy due to limitation on their reservoir's water level. Caliraya-Botocan-Kalayaan (CBK) complex has the highest energy capability of 4,015 MWh which equivalent to about 24% of the energy it can produce when operating twenty-four hours at full load.

During dry season, hydro plants are expected to have limited capacity output due to lower reservoir level while during wet season, hydro capacity may be maximized.

5.5 System Security

System security is simulated by considering the current SO practice of applying the Single-Outage Contingency Criteria. Single-outage contingency means that outage of any line in the system will not produce a predefined overload value. To approximately capture the contingency used by SO, line capacities will be set to 80% of the normal rating of the transmission lines.

5.6 Must Run Plant

To provide for a level quantification of the objectives, no plant will be treated as must-run, whether for reliability or economic purposes.

5.7 Reserve Requirement

Reserve requirement will be modeled as a static system requirement. To quantify the objectives in a uniform manner, an energy optimization only approach (no reserve co-optimization) will be included in the simulation. However, reserve requirements, i.e. regulating and contingency requirement will be simulated by netting off the reserve requirement on the energy output offer of nominated plants which are typically (at present conditions) being used to provide the necessary reserve requirements.

5.8 Generator Price and Quantity Offers

Generator offers will be based on a single block offer using planning values of the variable cost. This means that the optimization will consider a single price for a whole generator energy offer. This approach aims to facilitate a level quantification of generator offers based on the capability and variable cost associated with a certain type of plant. The variable cost captures the basic economic costs of the plants and refers mainly to the fuel costs associated with the plant.

5.9 Generator parameters

The basic generator parameters included in the optimization includes the maximum and minimum generator capacity and the associated ramp up and ramp down rates. The maximum generator capacity refers to the MW capability of the generator (including any dispatchability limitation) while minimum MW capacity refers to the minimum stable

load. Ramp rates are design capability of generators to increase or decrease its MW output.

5.10 Seasonal Assumption

Seasonal variation to capture a one year representation of simulated market will be approximated by assuming that the May month represents a dry season period while the September month represents a wet season period. The dry season period will include the months of March, April, May and June while the wet season period will include the months of July, August, September, October, November, December, January and February.

5.11 Market Dispatch

The simulation will consider an hourly ex-ante dispatch for the Day-Ahead Market and assumes no imbalance during any trading interval.

5.12 Transmission Line Capacity

Transmission line capacity for 230 kV lines is set at 300 MW and 2650 MW for 500 KV lines. The N-1 contingency consideration, however, will derate the capacities by 20%.

5.13 Dispatchable Demand

For purposes of simplifying and quantifying the simulations, no demand bidding will be included.

6.0 Simulation Tool

6.1 Luzon Demonstration Market System (DMS)

The DMS or dispatch engine is a spreadsheet based linear optimization solver capable of performing energy optimization with reserve co-optimization. The system is modeled using DC Load Flow approximation and incorporates transmission losses. Transmission loss is added at the receiving node of the line and becomes part of the total energy served in the system.

The optimization process takes into account several constraints representing the characteristics of the system. These constraints include, but not limited to the following:

- a. Constraints representing limits on generation offer, demand and applicable reserve quantities.
- b. Constraints representing the technical characteristics of reserve facility categories.

- c. Energy balance equations for each node in the market network model.
- d. Constraints representing limitations on ramp rates.
- e. Constraints defining system reserve requirements.
- f. Capacity constraints on each transmission line.

At present the DMS also incorporates several limitations which includes the disregard for the initial loading of the generators. This means that for every period the generators were assumed to have zero loading. Another limitation is that during optimization when the load for the supposed marginal plant cannot be satisfied without violating minimum stable generation (Pmin) and no generator can satisfy serve that load without Pmin violation, the engine will automatically dispatch the whole Pmin of the marginal plant and subtract the added energy to the next cheaper plant in merit order. This is primarily due to the limitation of the optimizer (What's Best linear solver) used by the engine and also due to the non-incorporation of the constraint violation coefficients in the engine algorithm. However, the engine incorporates a value of lost load (VoLL) amounting to P 20,000 per MW and represented as a virtual generator that will be triggered if there is no sufficient capacity to meet the required demand.

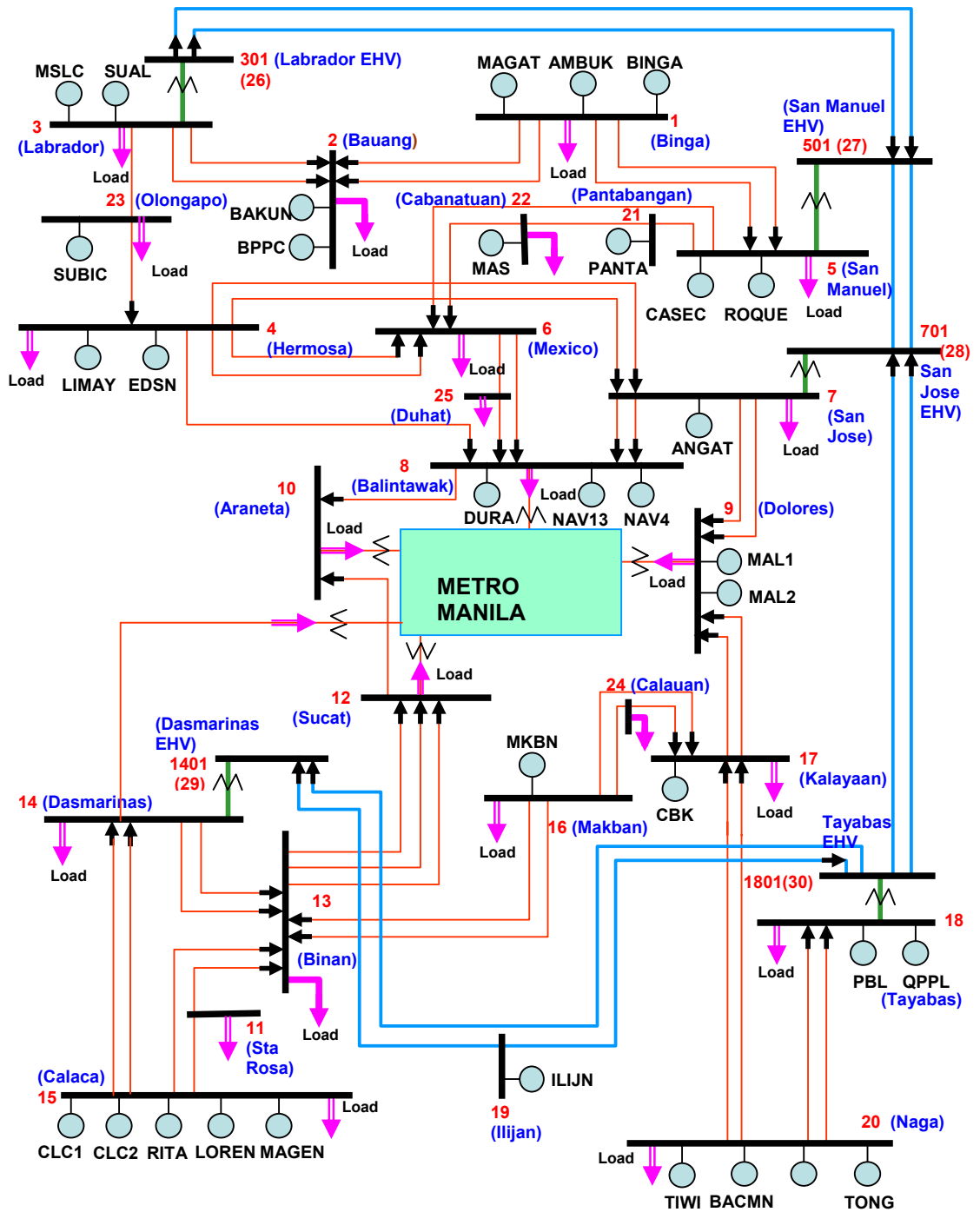
6.2 Market Network Model

The Market Network Model used in the simulation is the 30-Bus simplified Luzon grid system (Figure 6.2). The Market Network Model used is a reduced network based on 2003 Luzon Transmission Network. A simplified network is used to remove the complexity of the system resulting to faster optimization solution without compromising system characteristics and generator interconnection. The 30 node system was developed by performing a series of loadflow simulations to capture the inherent characteristics of the Luzon grid.

The MNM is composed of thirty (30) nodes interconnected by twenty-six (26) branches consisting of 500 kV and 230 kV lines. It has thirty (30) generators representing the different plants in Luzon grid including the HVDC link which is represented as generating plant. The generators were modeled based on their fuel cost characteristics. That is, generating units with the same fuel cost characteristics located in the same plant were represented as one unit, while generating units (even if they are located in one plant) with different fuel cost characteristics were represented as individual units. An example of this case is the Calaca and Malaya plants where the plants have multiple units in their respective plants but have different fuel cost characteristics; hence their units were modeled as separate generating units. To simulate customer zonal pricing in the model, the nodes have also been divided into three customer pricing zones, namely: North Luzon, Metro Manila, and South

Luzon nodes. Appendix 2 shows the Luzon Power System map with the corresponding pricing zones.

Figure 6.2 30-Bus simplified Luzon grid system



To complete the MNM, generator and load locations are determined and assigned to the Market Trading Nodes according to their actual location in the system. Nodal demand allocated to each node is calculated on a pro-rated basis based on the system demand and typical day load profile of the Luzon grid. Appendix 3 details the market trading nodes and nodal demand allocation.

6.3 Simulation Scenario Development

The generation and load have different characteristics in wet and dry seasons, hence seasonal variation are included in the simulation. Dry season generation has lesser capacity in Hydro plants while higher demand level is expected. The months considered are May and September for dry and wet season respectively.

An unconstrained system is where power flows in transmission lines are less than the rated capacity of the transmission lines. This is the case where there is no congestion or line limit violation.

A constrained system is experienced when there is congestion or line power flow limitation. As with unconstrained system, all plants are also made available, however, typical constrained lines, reflected in the SO daily operation highlights include Concepcion-Mexico, Dasma-Binan, Olongapo-Hermosa, and Duhat-Balintawak 230 KV transmission lines.

7.0 General methodology

The following will be the general simulation methodology in achieving the objectives of the simulation.

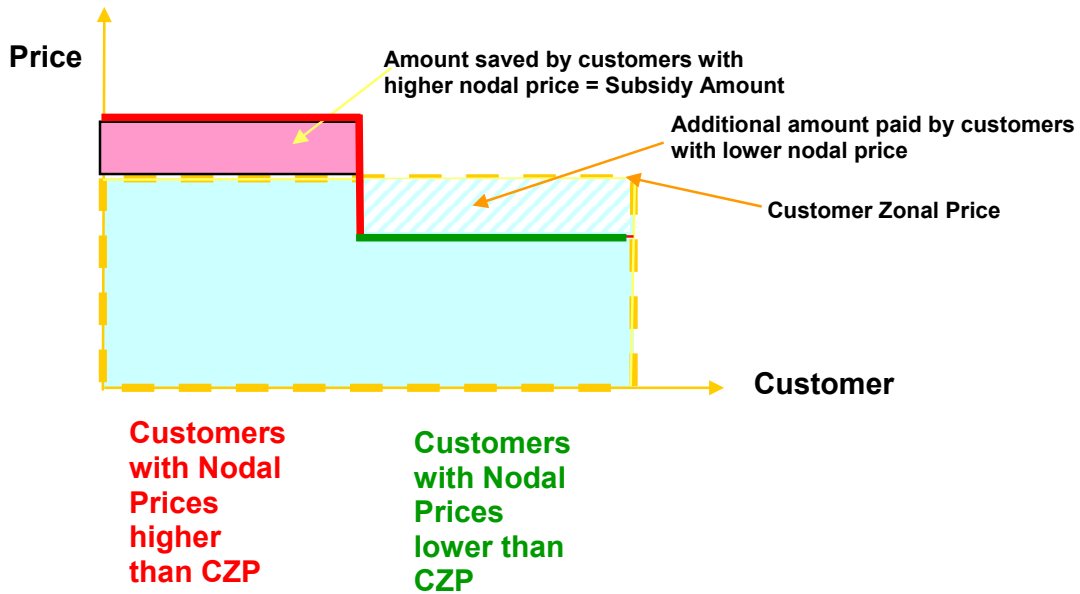
- 7.1 Establish the system condition using the input data and assumptions, including, but not limited to:
 - Hourly System Demand
 - Hydro limitations
 - Generator and Line outages
 - Allocation of generator capacity for reserve
- 7.2 Perform the market Simulation using the Luzon DMS.
 - Calculate Nodal Prices and Dispatch Schedule.
- 7.3 Determine cross subsidy in an hourly basis.
- 7.4 Calculate market settlement and corresponding market surplus on an hourly basis
- 7.5 Expand analysis to cover one year horizon.

8.0 Determination of Cross Subsidy

Zonal price is the load weighted average of nodal prices covered by the defined zone. As such, customer connected to the node with lower price is deemed to subsidize the customer connected to the node with higher price. Cross subsidy could be determined by taking the difference between customer zonal price and nodal prices for each zone and multiplying it by the energy drawn by nodal customers. The LDMS is capable of computing each customer settlement using customer zonal price or customer nodal price and from these prices the cross subsidy could be obtained. Figure 8.1 illustrates the determination of cross subsidy in considering zonal as well as nodal pricing. The following procedure provides the methodology in determining the potential cross subsidy:

- a. Determine CZP considering
 - Three Zones: North Luzon, Metro Manila, & South Luzon
- b. Compute Customer Zonal Payment ($CZPay = CZP \times QC$)
- c. Compute Customer Nodal Payment ($CNPay = NP \times Qc$)
- d. Subsidy is the Difference between Nodal & Zonal Payments
 - If $CZPay > CNPay$: Customer Subsidizes
 - If $CZPay < CNPay$: Customer is being subsidized
- e. Determine Amount Paid by Subsidizing Customers
- f. Determine Amount Paid by Subsidized Customers

Figure 8.1 Cross Subsidy Illustration

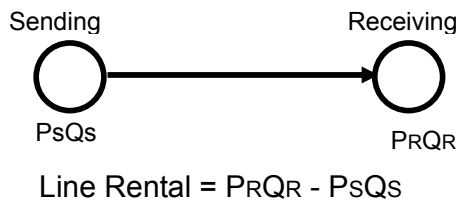


9.0 Determination of Market Surplus (Line Rental)

Market surplus or line rentals are the surplus created in the electricity market as a result of locational marginal pricing (LMP) wherein transmission losses and congestions are priced at marginal cost. Figure 9 below shows the LMP and line rental concepts.

Figure 9. LMP and Line Rental Amount

$$\text{LMP} = \text{Generation Marginal Cost} + \text{Transmission Congestion Cost} + \text{Cost of Marginal Losses}$$



The price difference between nodes reflects the marginal costs of losses and of transmission congestions. Line rentals are composed of two interrelated types of costs: the cost of marginal losses (i.e. loss rentals) and the marginal costs of any power system congestion (i.e. congestion rentals).

It therefore follows that if there is no congestion, then there are no rentals due to congestion while rentals due to losses will always be present. However, in physical terms, whenever a constraint occurs in the system it will affect losses, and in many cases losses can cause constraints. This condition blurs the distinction between loss and constraint rentals when congestion is encountered in the system..

9.1 Determination of Net Settlement Surplus (Rental)

Line loss and congestion (constraint) cause settlement surplus in the Market trading. Net settlement surplus can be obtained by taking the difference between payment to generators and collection from customers.

9.2 Determination of Surplus (Rental) due to Line Loss and Congestion

Surplus due to line loss can be determined if there is no constraint. Line loss surplus is the net settlement surplus if there is no constraint. However, constraint surplus percentage could be estimated by averaging the line loss surplus in unconstrained dispatch then subtracts it to the net settlement surplus in constrained dispatch. The following is the procedure in determining the line loss and constraint rentals:

- a. Calculate hourly Net Settlement Surplus for May and September.
- b. Identify and segregate unconstrained and constrained periods.
- c. Calculate hourly loss rentals during unconstrained period.
- d. Calculate average hourly loss rental (ALR) during unconstrained period

$$ALR = \sum \text{unconstrained loss rentals} / \text{no. of unconstrained periods}$$

- e. Calculate Monthly Constraint Rental (MCR)

$$MCR = \sum (\text{surplus during constrained period} - ALR)$$

- f. Calculate Monthly Loss Rental (MLR)

$$MLR = ALR \times \text{no. of constrained periods} + \text{loss rentals during unconstrained periods}$$

10.0 Simulation Result

The following sections show the results of simulation based on the methodology discussed in the previous section.

10.1 Cross Subsidy Simulation Result

Table 10.1 shows the result of subsidy simulation. The monthly subsidy was computed by taking the total hourly per node difference between the customers' payment based on zonal price and customers' payment based on nodal price.

**Table 10.1 Customer Zonal vs. Nodal Pricing Simulation Results
In Million Pesos**

MONTH	September (Wet Season)	May (Dry Season)
Energy Consumed by Customers, GWh	3,310	3,574
Total Customer Payments based on Customer Zonal Pricing	8,688	9,199
Total Customer Payments based on Customer Nodal Pricing	8,688	9,199
Additional amount Paid by customers with lower nodal price	559	684
Amount saved by customers with higher nodal price = Subsidy Amount	559	684
% Subsidy	6.43 %	7.44 %
Annual Amount saved by customers with higher nodal price = Annual Subsidy	7,207	

10.2 Market Price Spread

Considering the extreme system condition, the spread of prices in the market simulation, nodal as well as zonal prices were graphed for the months of May and September. A one week snapshot of the graphs is shown in figures 10.1 to 10.6. The resulting price spread is shown in Table 10.2 below.

The graphs illustrate the prices for the North Luzon, Metro Manila, and South Luzon pricing zones. Correspondingly, nodal prices of selected nodes or substations are also indicated. Prices for a single Luzon pricing zone have also been incorporated to show the zonal prices if the Luzon grid is treated as a single zone.

Figures 10.1 and 10.4 shows the level of prices for the North Luzon for months of May and September respectively, while Figures 10.2 and 10.5 shows the Metro Manila price graphs and Figures 10.3 and 10.6 shows the price graphs for Southern Luzon. North Luzon pricing zone shows the prices for the Hermosa, San Manuel, Bauang, and Cabanatuan nodes. Metro Manila pricing zone shows

the prices for Araneta, Balintawak, Dolores, and Sucat nodes, while South Luzon pricing zone shows the prices for the Binan, Calaca, Dasma, and Tayabas nodes.

Table 10.2 Nodal and Zonal Price Spread

NODAL AND ZONAL PRICE SPREAD (P/kWh)		
	Nodal	Zonal
North Luzon	1.60 – 5.00	1.80 – 4.00
Metro Manila	1.80 – 5.20	2.00 – 4.30
South Luzon	1.20 – 5.00	1.80 – 3.80

10.3 Line Rental Simulation Result, In Million Pesos

Considering the wet and dry season nodal prices determined from the simulation. Customer collection and generator payments were calculated based on nodal prices. The market surplus represents the difference between the market collection and payments. Applying the methodology discussed in Section 9, market surplus due to constraint was derived (MCR) and correspondingly the market surplus due to losses was calculated. The monthly results were then translated to correspond to a one year period to provide for the estimated annual amounts of the market surplus due to losses and constraints. Table 10.3 shows the simulation results.

Table 10.3 Line Rental Simulation Summary

MONTH	September (Wet Season)	May (Dry Season)
Total Energy Transacted, GWh	3,310	3,574
Customer Collection	8,688	9,199
Generator Payment	7,457	7,935
Net Settlement Surplus	1,231	1,264
Monthly Line Loss Rental (MLR)	263	336
Monthly Constraint Rental (MCR)	968	928
Annual Line Loss Rental	3,451	
Annual Constraint Rental	11,425	
Annual Customer Payment	106,299	
Annual Payment to Generator	91,395	

To estimate the range of the market surplus, the number of periods for each month which encountered transmission congestion was counted to derive the degree of time period wherein constraints are encountered by the market simulation with n-1 contingency (worst case). The same procedure was done for a market simulation with no contingency constraint (normal case). The corresponding surplus range was then pro-rated to the derived percentage level of the surplus range. The line rental percentages summary is shown in Table 10.4. The percentage of constrained period is the frequency of occurrence of constrained period with respect to the total simulation period. The percentage surplus range is the range of surplus with respect to customer payment from normal case to worst case.

Table 10.4 Line Rental Percentage

% Constrained Period (Worst Case)	65 % (of time)
% Constrained Period (Normal Case)	38 % (of time)
% Surplus Range (Max) – Worst Case	14 %
% Surplus Range (Min) – Normal Case	5.8 %

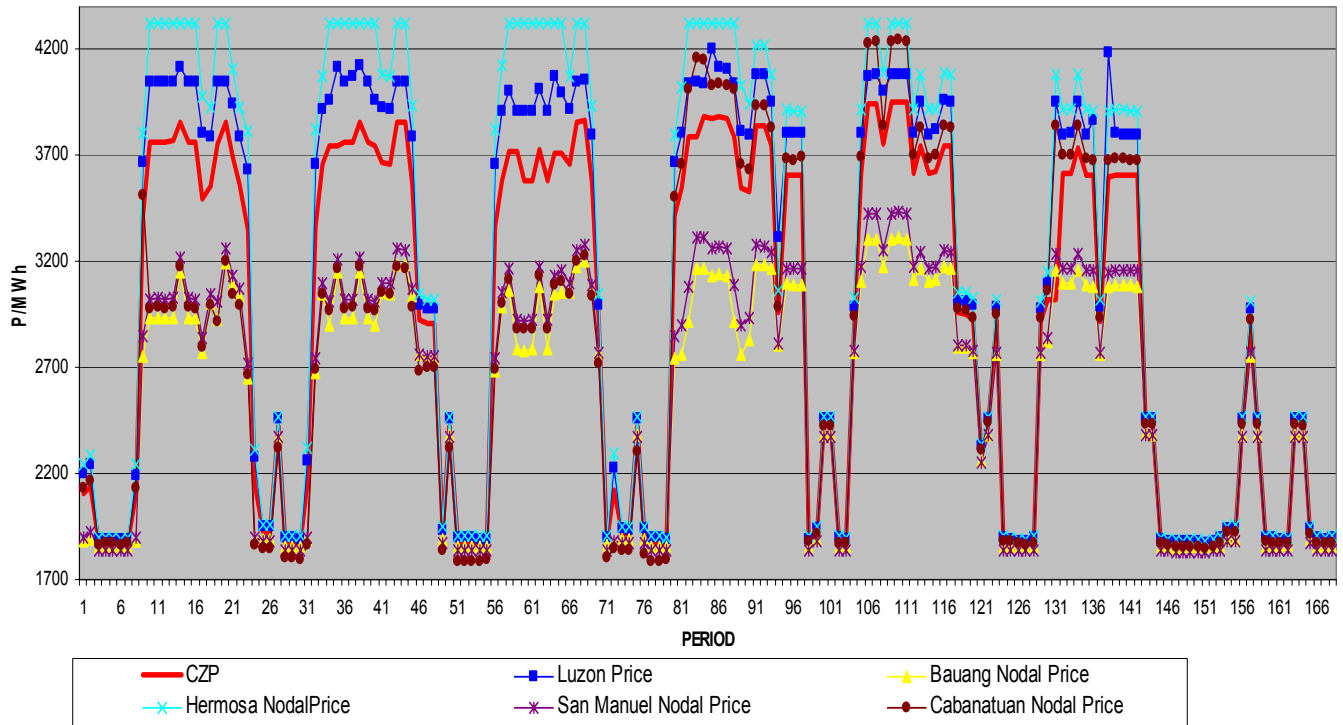


Figure 10.1 Market Prices for North Luzon – 1 Week of May (Extreme System Condition)

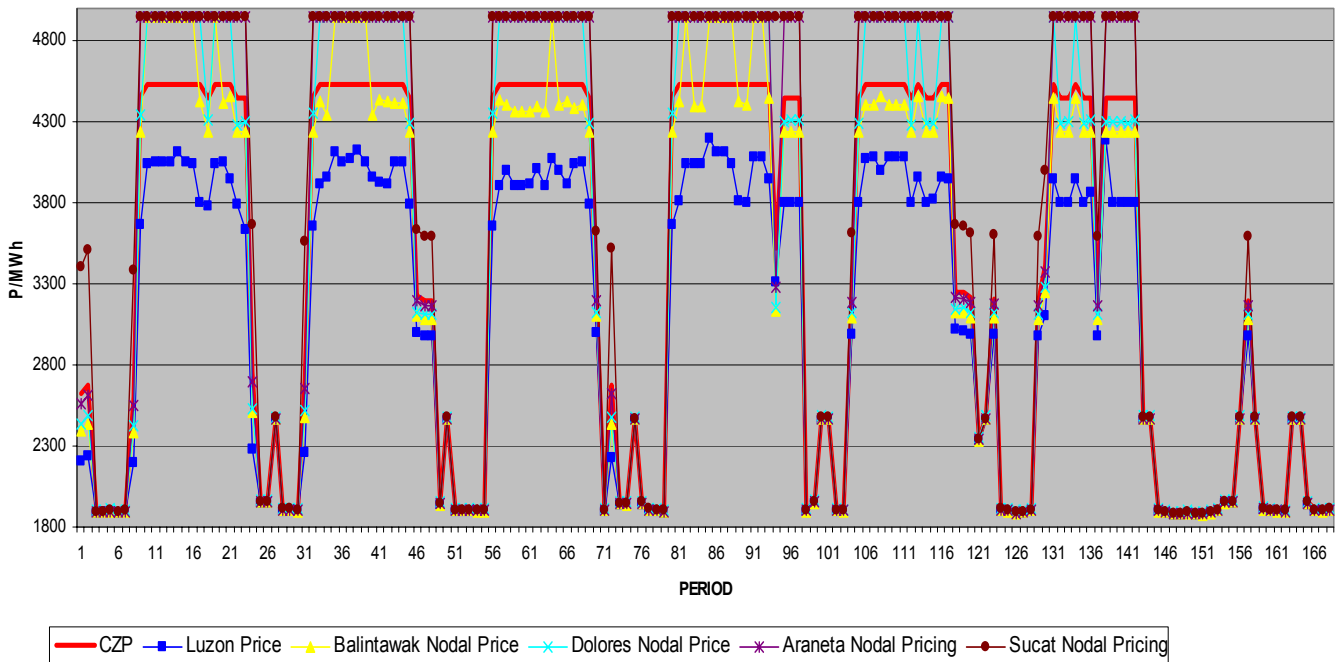


Figure 10.2 Market Prices for Metro Manila – 1 Week of May (Extreme System Condition)

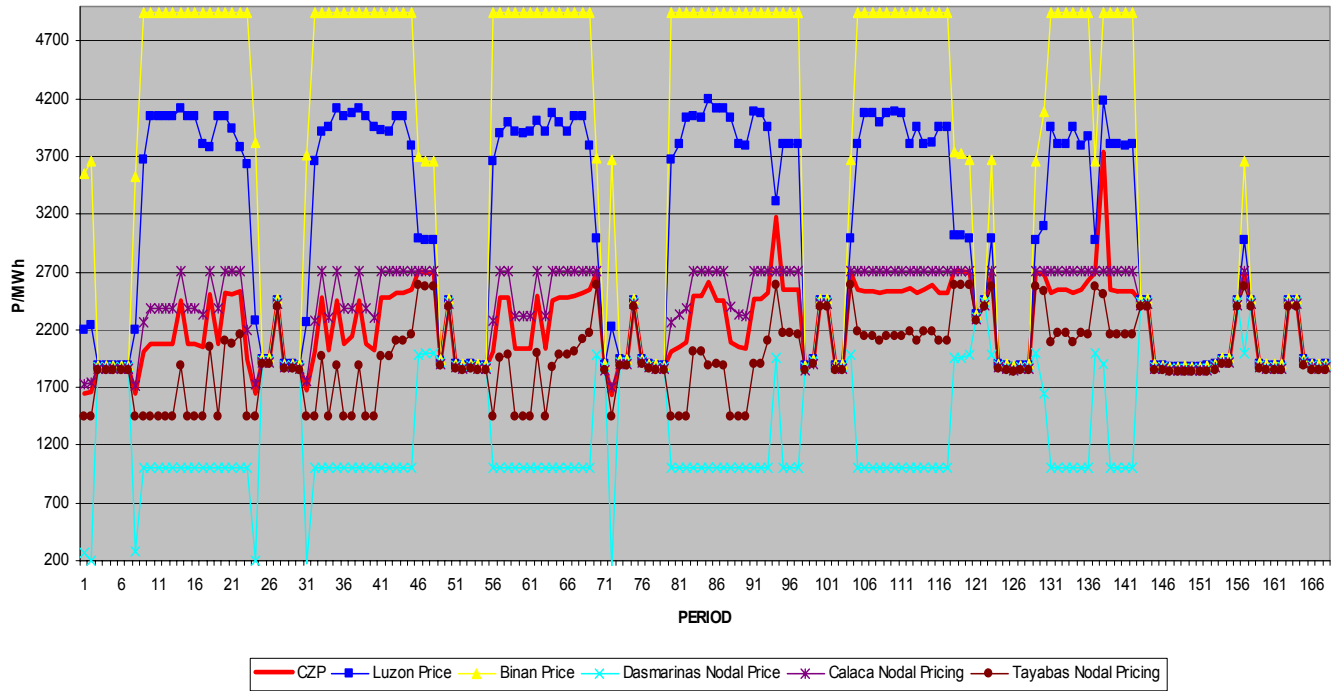


Figure 10.3 Market Prices for South Luzon – 1 Week of May (Extreme System Condition)

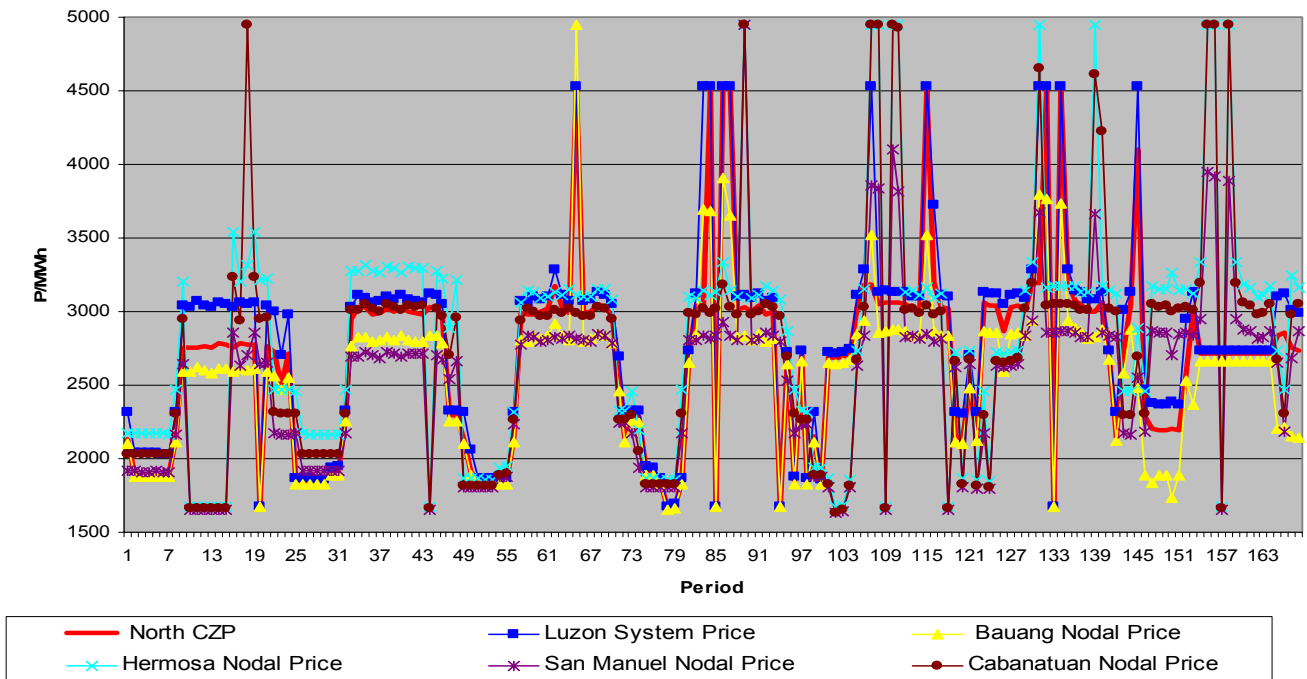


Figure 10.4 Market Prices for North Luzon - 1 Week of September (Extreme System Condition)

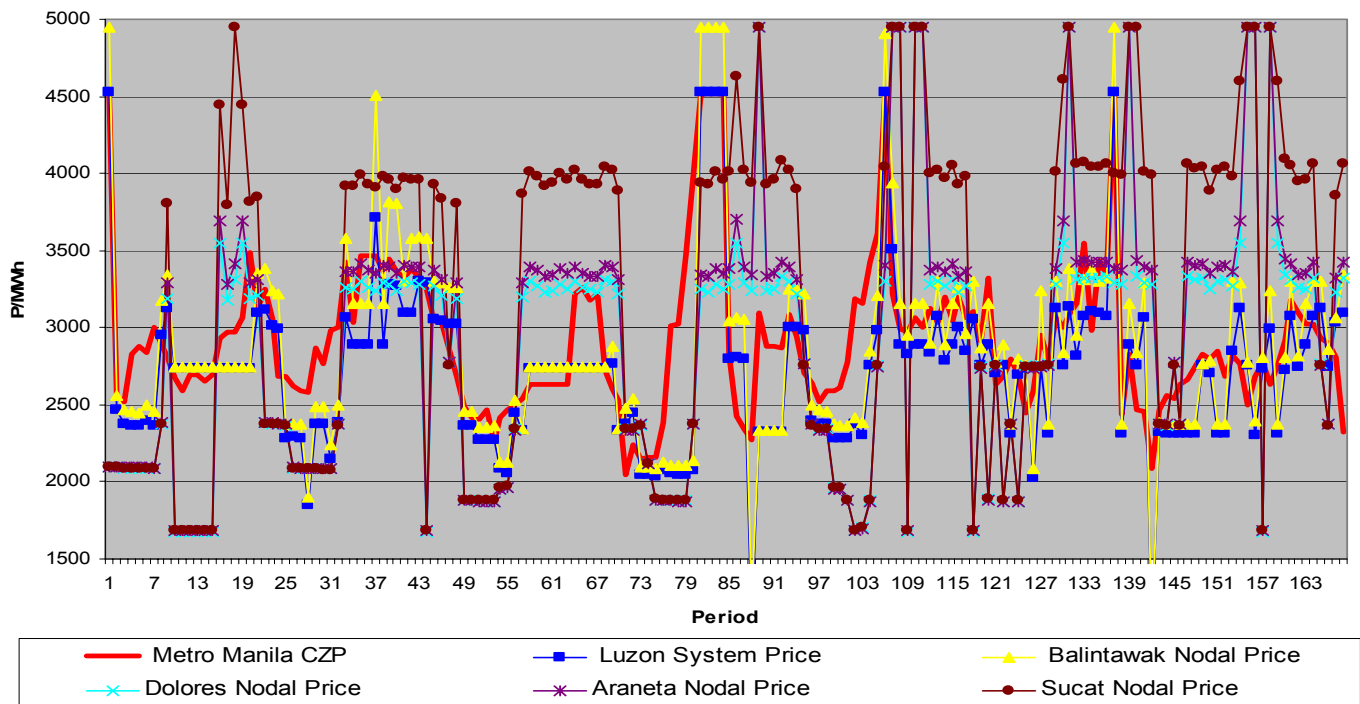


Figure 10.5 Market Prices for Metro Manila - 1 Week of September (Extreme System Condition)

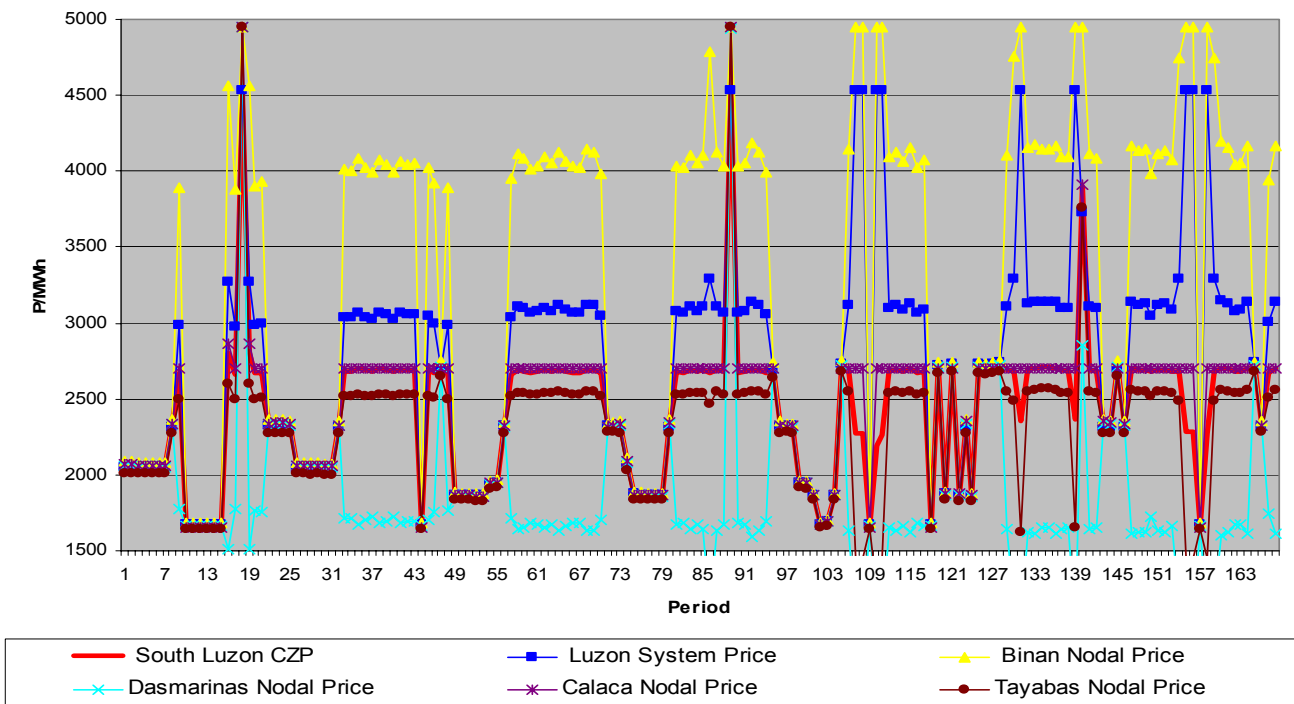
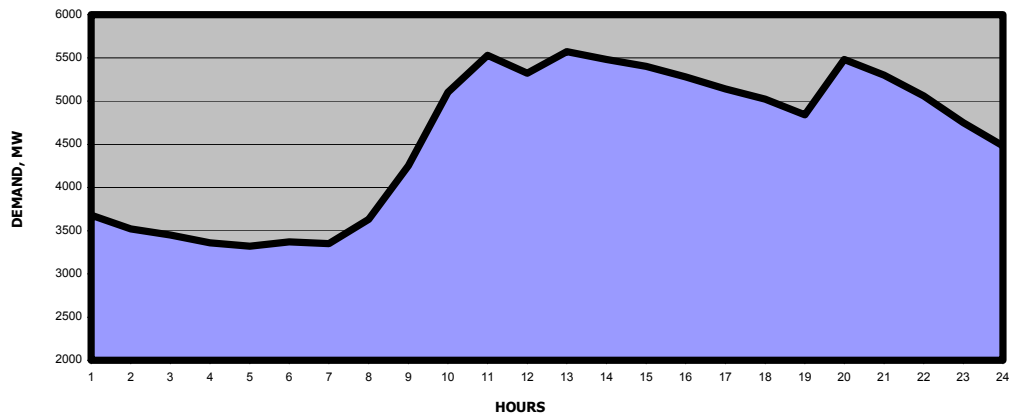


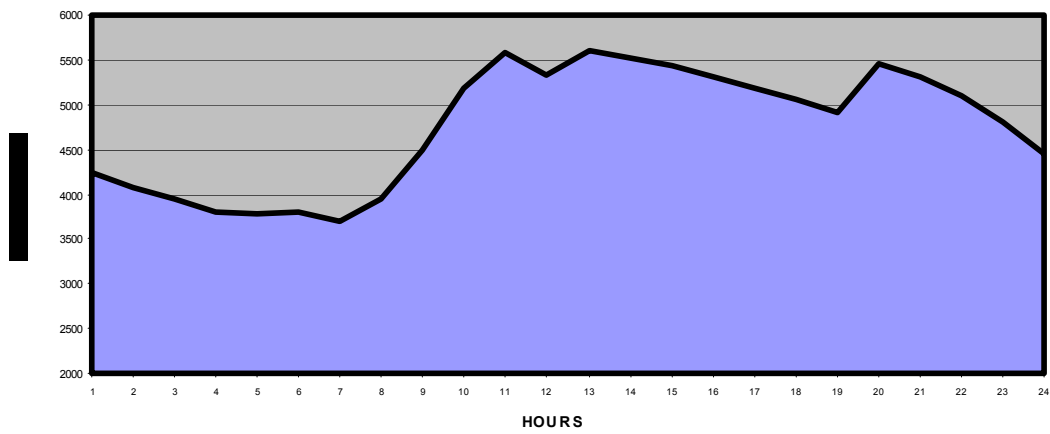
Figure 10.6 Market Prices for South Luzon - 1 Week of September (Extreme System Condition)

Appendix 1. Typical Load Profiles

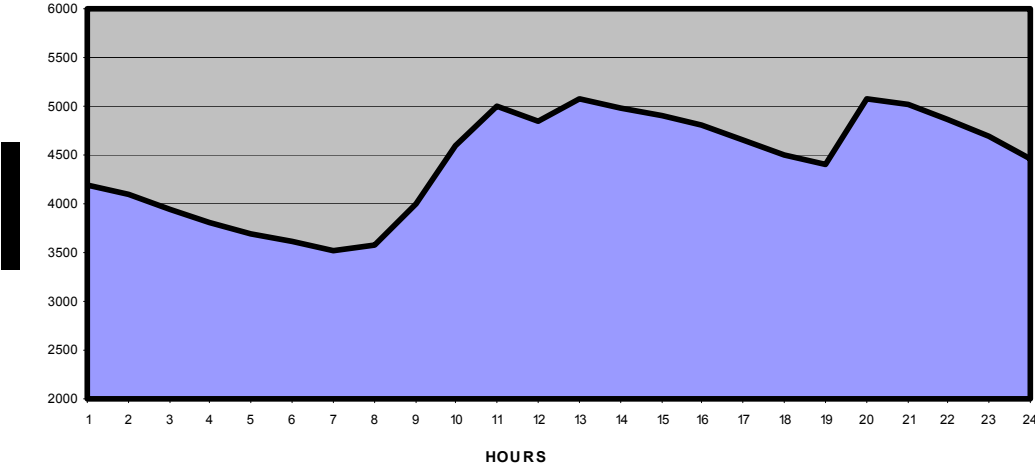
A. Monday Profile



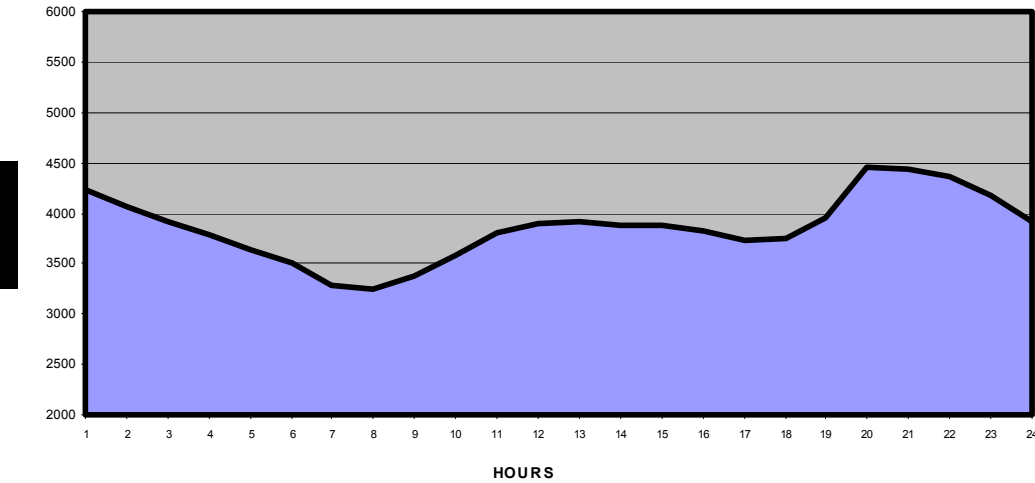
B. Tuesday- Friday Profile



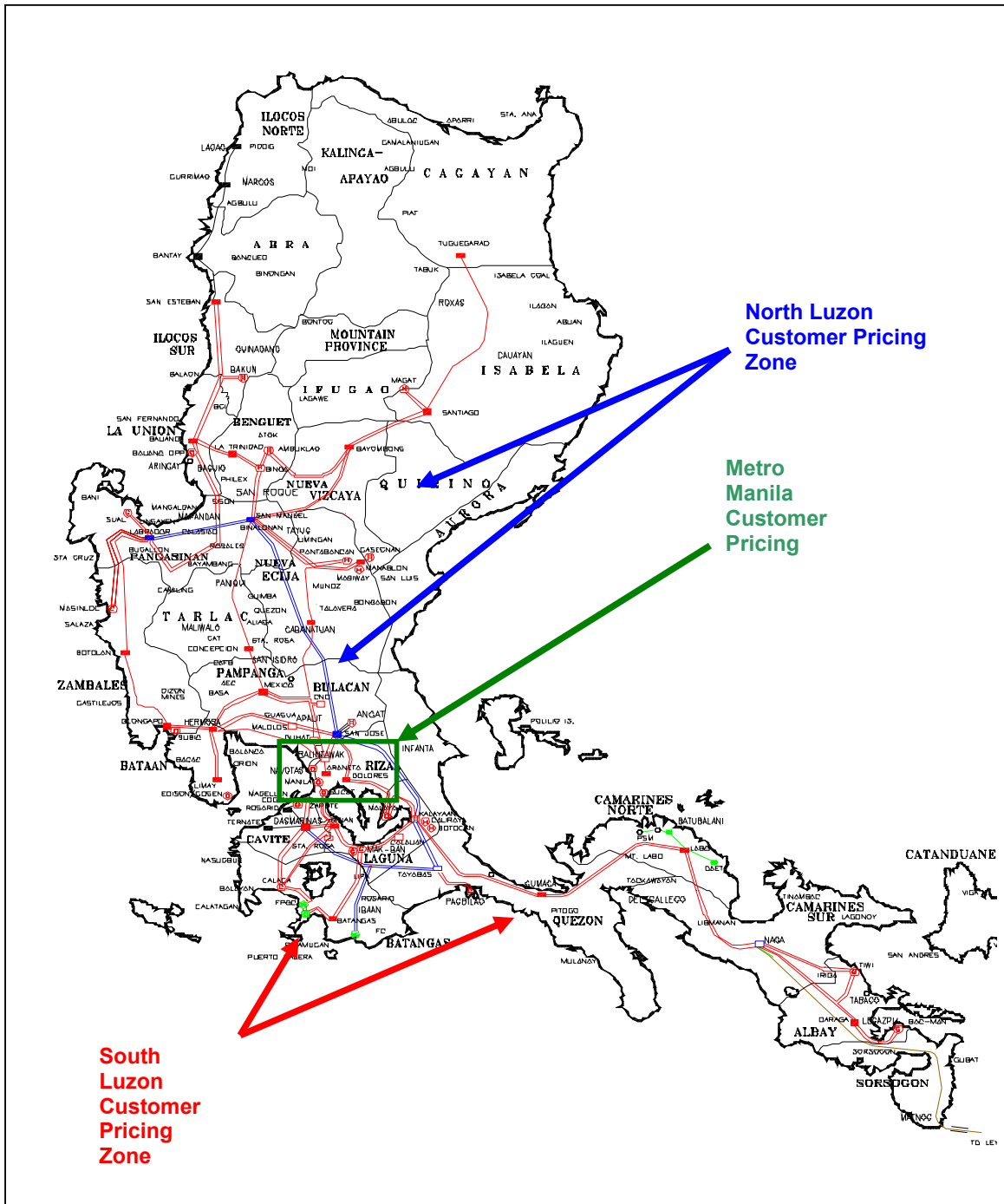
C. Saturday Profile



D. Sunday Profile



Appendix 2. Luzon Grid Customer Pricing Zone



Appendix 3. Generator Node Assignment

STATION NAME (PLANT NAME)	PLANT TYPE	GENSET ID	SUBSTATION	NODE ID
Pantabangan Hydro Electric Plant	Hydro	PANTA	Pantabangan	21
Casecnan Hydro Electric Plant	Hydro	CASEC	San Manuel	5
Masiway Hydro Electric Plant	Hydro	MAS	Cabanatuan	22
Limay Combined Cycle Power Plant	CC	LIMAY	Hermosa	4
Calaca Coal-Fired Thermal Power Plant 1	Coal	CLC1	Calaca	15
Calaca Coal-Fired Thermal Power Plant 2	Coal	CLC2	Calaca	15
Edison Diesel Power Plant	Diesel	EDSN	Hermosa	4
Makban Geothermal Power Plant	Geothermal	MKBN	Makban	16
Angat Hydro Electric Power Plant	Hydro	ANGAT	San Jose	7
Sual Coal-Fired Thermal Power Plant	Coal	SUAL	Labrador	3
Subic Diesel Power Plant	Diesel	SUBIC	Olongapo	23
Tiwi Geothermal Power Plant	Geothermal	TIWI	Naga	20
Binga Hydro electric Power Plant	Hydro	BINGA	Binga	1
Ambuklao Hydro Electric Power Plant	Hydro	AMBUK	Binga	1
Bakun Hydro Electric Power Plant	Hydro	BAKUN	Bauang	2
San Roque Multi-purpose Hydro Electric Power Plant	Hydro	ROQUE	San Manuel	5
Masinloc Coal-Fired Thermal Power Plant	Coal	MSLC	Labrador	3
Navotas 1-3 Gas Turbine Power Plant	GT	NAV13	Balintawak	8
Navotas 4 Gas Turbine Power Plant	GT	NAV4	Balintawak	8
Duracom Diesel Power Plant	Diesel	DURA	Balintawak	8
Leyte A Geothermal Power Plant	Geothermal	LEYTE	Naga	20
Caliraya-Botocan-Kalayaan Hydro Electric Power Plant Complex	Hydro	CBK	Kalayaan	17
Malaya 1 Thermal Power Plant	Thermal	MAL1	Dolores	9
Malaya 2 Thermal Power Plant	Thermal	MAL2	Dolores	9
Pagbilao Coal-Fired Thermal Power Plant	Coal	PBL	Tayabas	18
Magellan Diesel Power Plant	Diesel	MAGEL	Calaca	15
Torongan Geothermal Power Plant	Geothermal	TONG	Naga	20
Magat Hydro Electric Power Plant	Hydro	MAGAT	Binga	1
Bauang Diesel Power Plant Corporation	Diesel	BPPC	Bauang	2
Bacman Geothermal Power Plant	Geothermal	BACMN	Naga	20
Ilijan Natural Gas Combined Cycle Power Plant	Natural Gas	ILIJN	Ilijan	19
Sta. Rita Natural Gas Power Plant	Natural Gas	RITA	Calaca	15
San Lorenzo Natural Gas Power Plant	Natural Gas	LOREN	Calaca	15
QPPL	Coal Fired	QPPL	Tayabas	18

Appendix 4. Nodal Demand Allocation

Bus Number	Bus Name	Bus Voltage (kV)	Percent of Peak Demand
1	Binga	230	1.36
2	Bauang	230	3.26
3	Labrador	230	1.34
4	Hermosa	230	1.55
5	San Manuel	230	0.87
6	Mexico	230	4.34
7	San Jose	230	6.19
8	Balintawak	230	13.37
9	Dolores	230	16.33
10	Araneta	230	3.33
11	Sta. Rosa	230	2.51
12	Sucab	230	9.64
13	Binan	230	3.64
14	Dasmarinas	230	15.22
15	Calaca	230	1.41
16	Makban	230	2.09
17	Kalayaan	230	0.61
18	Tayabas	230	0.70
19	Ilijan	500	0.00
20	Naga	230	2.02
21	Pantabangan	230	0.00
22	Cabanatuan	230	1.01
23	Olongapo	230	1.55
24	Calauan	230	1.95
25	Duhat	230	5.72
301	Labrador (EHV)	500	0.00
501	San Manuel (EHV)	500	0.00
701	San Jose (EHV)	500	0.00
1501	Tayabas (EHV)	500	0.00
1801	Dasmarinas (EHV)	500	0.00
Total			100.00