FORECAST

PHILIPPINE ELECTRICITY MARKET CORPORATION JOURNAL



2016

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POWERING PROGRESS
2006 - 2016

Wholesale Electronics
Spot Market

FORECAST

PHILIPPINE ELECTRICITY MARKET CORPORATION JOURNAL



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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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ANNUAL MARKET ASSESSMENT

Report for the

2015 BILLING PERIOD

EXECUTIVE SUMMARY

The 2015 Annual Market Assessment Report (AMAR) provides an assessment of the results of the integrated Luzon and Visayas operations of the Wholesale Electricity Spot Market (WESM) for the period 26 December 2014 to 25 December 2015. It highlights significant observations on several indicators of market performance, trends and drivers, as provided for in the WESM Catalogue of Market Monitoring Data and Indices.

Sustained growth in the total WESM registered capacity was observed for the period covered, mainly driven by the entry of twenty-one (21) new generating units with a combined capacity of 984.3 MW. It is observed that majority of these new plants were preferential dispatch plants. Nevertheless, the share of new conventional generation facilities in terms of MW capacity remain large, with the additional capacity of new coal and natural gas plants accounting for 614 MW. By the end of year 2015, the total WESM registered capacity already stood at 16,140 MW, higher by 9.3 percent from the year-end figure in 2014, posted at 14,760 MW.

Of the total WESM registered capacity, only about 60 percent or an average of 9,450 MW was offered in the market during the year. About 12.9 percent was unavailable due to plant outages, posted at 2,019 MW while 14.9 percent or about 2,344 MW was on account of capacity not offered. Nevertheless, more capacities were made available this year, marked with a moderate 4.1 percent increase in the average offered capacity from last year's 9,076 MW to 9,450 MW. On the other hand, outage capacity declined by 4.0 percent from 2,103 MW, while capacity not offered rose by 5.2 percent from last year's 2,228 MW. About 5.9 percent averaging at about 928 MW corresponded to ancillary services which were scheduled by the System Operator. Meanwhile, the MRU designation of oil-based plant Malaya comprised 2.6 percent, averaging at 409 MW, while the available capacities for non-scheduled generation accounted for the remaining 3.8 percent of the WESM registered capacity, averaging at about 606 MW. It is observed that the capacities scheduled for ancillary services increased by about 20.5 percent from last year's average of 770 MW, while non-scheduled generation likewise grew significantly from an average of 157 MW in 2014.

Changes in the demand levels are generally predictable and followed seasonal patterns. Steady increase in the level of system demand was observed particularly during the first half of the year, coming from a low demand season at the beginning of the year due to colder temperature levels. Significant demand growth was posted during the summer months, demonstrated by the increase of about 8.3 percent in average demand from 7,741 MW in April to an average of 8,381 MW in May. While such growth was sustained through the June billing month, seasonal decline in the demand level was noted beginning July, marked with a 5.4 percent decrease in the monthly average demand level from 8,407 MW in June to 7,952 MW. No significant change in the monthly system demand was noted during the second half of the year, except for the month of December when demand levels dropped to 7,804 MW attributed to the holiday season and colder weather temperatures.

On the other hand, effective supply levels indicated an increase by about 2.8 percent from an average of 8,936 MW in the previous year to 9,190 MW. Though effective supply growth was modest this year, supply availability during periods with projected low supply levels as well as the high-demand summer season notably improved when compared to last year. The lowest monthly effective supply level was posted during the January and February billing months, averaging at 8,175 MW and 8,147 MW, respectively, when demand levels were also low. The high outage level during these months was driven by the high incidence of planned outages among the large generating coal plants. High outage capacity continued to drive supply levels down until the first half of the March billing month. Consequently, moderate increase in the

effective supply level averaging at 8,625 MW was observed in March. Effective supply continued to increase through May, at an average of 9,589 MW, but begun to post a decline beginning June, averaging at 9,253 MW. Supply crept further down in July at 9,137 MW. Narrow supply margins prevailed in May and June, averaging at 1,209 MW and 635 MW, respectively, mainly on account of the higher demand requirement associated with the summer months. On the other hand, the July to September billing months followed an increasing supply trend due to the fewer plant outages during these months. However, as more plants went on outage during the 4th quarter of the year, corresponding decrease in the level of supply was likewise noted during this period.

Notwithstanding, significant increment in supply was observed in the last week of the December billing month attributable to the increase in capacity offers from generator-trading participants. It may be recalled that the central scheduling and dispatch of energy and contracted reserves in the WESM (for the Luzon region only) was implemented effective 22 December 2015. This required all generator trading-participants with ERC-approved Ancillary Services Procurement Agreement (ASPA) to submit their reserve offers to the market corresponding to the day-ahead ancillary service schedule approved by the System Operator (SO).

Supply margins widened during the last week of the year as demand levels dropped during the holiday season while effective supply levels grew, with posted increase in the capacity offers in the market during the period. Wide supply margins were likewise observed coinciding with the significant dips in demand during the first week of the billing year, the observance of the Holy Week in April and the Ninoy Aquino holiday in August. Overall, average supply margin widened by about 10.3 percent to 1,386 MW from 1,257 MW in the previous year.

Outage capacity decreased by about 4.0 percent from last year's average of 2,103 MW to 2,019 MW this year. Coal plants posted significant increases in its outage capacity during the first and fourth quarters of the year, driving outage capacity at its highest during the first quarter, averaging at 2,722 MW, 2,976 MW and 2,383 MW from January to March. Lower outage capacity levels during the summer months of April and May was observed attributed to 81.8 percent decrease in the outage capacity of coal plants from an average of 1,119 MW in March to 204 MW in April, and 240 MW in May. Nevertheless, outage capacity remained high in the June and July billing months, averaging at 1,969 MW and 2,079 MW, respectively, when all resource types posted a relatively higher level of outage capacity. Outage capacity level dropped in the third quarter and recorded the lowest monthly average outage capacity during the September billing month at 1,441 MW. Outage capacity of coal plants again increased during the last quarter, averaging at 1,237 MW, in part influencing the high outage capacity from October to December, averaging at 1,771 MW, 2,238 MW and 2,220 MW, respectively.

Generator-trading participants continued to submit capacity offers less than their respective maximum available capacity, as indicated by the persistently high level of capacity gap throughout the billing year 2015. Capacity gap levels manifested a 5.2 percent increase this year from an average of 2,228 MW in 2014 to 2,344 MW. The April and May billing months posted the highest monthly average capacity gap at 2,766 MW and 2,860 MW, respectively, while the billing months of October and November marked the lowest monthly capacity gap levels at an average of 2,038 MW and 2,069 MW, respectively. Consequently, average capacity gap levels were observed to be generally higher during the first semester than the second semester of the year. Among all resource types, hydro plants continued to account for majority or 40.4 percent of the system-wide capacity gap, averaging at 948 MW, followed by coal plants, accounting for 26.5 percent at an average of 622 MW.

Market prices were generally lower this year when compared to the previous year, averaging at PhP3,824/MWh, from PhP4,835/MWh in 2014. It is noted that no imposition of the secondary cap[1] was made all throughout the year.

Market prices averaged at PhP3,381/MWh in January and continued to rise by about 50.9 percent in February as system-wide market prices averaged at PhP5,101/MWh. The high market prices during the period was generally driven by the low availability of supply due to the rise in outage capacity, particularly from major coal plants which were mostly on planned outage. Better supply and demand condition was experienced for the most part of March, resulting in the minimal increase of 0.1 percent during the period, with market prices averaging at PhP5,105/MWh. In April, market prices further declined by about 44.7 percent to PhP2,824/MWh following the decrease in the capacity on outage involving coal plants this month. Significant demand increase led to the 59.8 percent increase in the system-wide market prices in May, averaging at PhP4,512/MWh. Notwithstanding, the same is observed to be lower when compared to previous year's PhP6,302/MWh. In June, the monthly system-wide average market price significantly rose by 41.9 percent, to PhP6,402/MWh. The same is an increase by 10.9 percent from the previous year's PhP5,772/MWh.

Market prices followed a decreasing trend from July until September, averaging at PhP4,473/MWh, PhP3,729/MWh and PhP2,168/MWh, respectively, as a result of the better supply conditions that prevailed throughout these months. Average market prices went slightly up in October at PhP3,249/MWh, and continued to increase at PhP3,249/MWh in November, following tighter supply conditions. Finally, drop in market prices were observed in December averaging at PhP2,487/MWh.

The maximum price on record was posted at PhP30,234/MWh on 29 May at 1400H, coinciding with the forced outage of major coal plant Pagbilao 1 on top of the existing forced outage of coal plant SLTEC during the month.

Luzon coal plants Sual, Masinloc, Pagbilao and Mariveles dominated the list of price-setters across all price levels during the billing year followed by Visayas coal plants KSPC and PEDC and natural gas plants Ilijan in Luzon and Leyte A in Visayas. Meanwhile, prices within the range of above PhP5,000/MWh were most frequently set by oil-based plants. Oil-based plants Navotas and EAUC topped the list, followed by PEDC, Bauang, Nabas and TPC (Carmen), Subic and TAPGC. Hydro plants Magat and Kalayaan likewise figured in the list of price setters during the billing year.

On the other hand, major coal plant Sual dominated the list of pivotal suppliers, followed by natural gas plants Ilijan, coal plants Pagbilao, Masinloc, Calaca and Mariveles and natural gas plant San Lorenzo. It was observed that the frequency by which generators became pivotal rose significantly during the May and June billing months, which are the peak demand months, marked with tight supply and demand balance. On the contrary, manifesting the better supply and demand condition during the period, the September billing month posted the lowest number of pivotal suppliers, consistent with its low incidence of RMI level of less than 10 percent during the billing year.

Following the tight demand and supply conditions in May and June, the presence of pivotal suppliers manifested in majority of the trading intervals during these months, indicated by the

1 ERC Resolution No. 20, series of 2014 entitled "Adopting and Establishing a Pre-Emptive Mitigation Measure in the WESM" sets the cumulative price threshold (CPT) equivalent to an average spot price of PhP9,000/MWh over a rolling 7-day period or 168 trading intervals. A breach of the CPT triggers the imposition of a price cap amounting to PhP6,245/MWh.

number of times the market RSI fell below the 100 percent mark (53.1 percent in May and 68.8 percent in June). The rest of the billing months manifested improved supply conditions, with the market RSI exceeding 100 percent most of the time, indicating the absence of pivotal suppliers.

The spot market exposure of generators averaged at 12.0 percent, while the remaining 88.0 percent was covered by bilateral contracts. The billing months of March, April and July posted the highest monthly spot exposure among generators at an average of 13.5 percent, 13.6 percent and 13.4 percent, respectively. On the other hand, the spot market exposure of customers accounted for 9.8 percent of the total energy withdrawn while the majority or 90.2 percent was covered by bilateral contracts. Corresponding to the trend in the spot exposure of generators, customers' spot exposure were higher during the April billing month, averaging at 11.6 percent and also in March and July, both with 11.2 percent. In contrast, the spot exposure of WESM customers was lowest during the January billing month at only 7.3 percent.

Similar to the previous year, the market remained dominated by four major participant groups which combined market share accounted for 63.5 percent of the total WESM registered capacity for billing year 2015. San Miguel Corporation (SMC) retained the top spot with the biggest share of the market this year at an average of 20.3 percent, followed by Aboitiz Power (AP) with 15.8 percent, First Gen Corporation (FGC) with 15.1 percent and Power Sector Assets and Liabilities Management Corporation (PSALM) with 13.7 percent.

Calculated by major participant grouping, the resulting HHI based on the WESM registered capacity indicated that in general, the market is moderately concentrated during the year. Based on actual generation, however, it is observed that the HHI during the February billing month hit the concentrated mark, attributable to the decline in the actual generation of major coal plants Masinloc, GN Power, QPPL and SLTEC and the corresponding increase in the market share of dominant groups SMC and FGC. Note that outage capacity was highest during the February billing month. Grouping by trading participant and by generating plant, respectively, indicated that the market is generally not concentrated in year 2015.

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INTRODUCTION

The 2015 Annual Market Assessment Report (AMAR) provides an assessment of the results of the integrated Luzon and Visayas operations of the Wholesale Electricity Spot Market (WESM) for the period 26 December 2014 to 25 December 2015. The AMAR, which follows the WESM Catalogue of Market Monitoring Data and Indices (CMMDI), sets-out an overview of the results of market performance, trends and drivers which in turn provide the means by which to assess competition and conditions in the WESM, as well as the bidding behavior of trading participants, in support of the attainment of the WESM objectives to establish a competitive, efficient, transparent and reliable market for electricity.

ENERGY DEMAND

DEMAND[1]

Historical Demand

Maximum demand in Luzon for year 2015 grew by about 3.8 percent at 8,824 MW, from last year's 8,497 MW. This year's peak demand is noted to be the highest in the region over the course of ten years, from the commencement of the WESM operations in Luzon on 26 June 2006 when peak demand was posted at only 6,361 MW. Notwithstanding, said increase in peak demand is still below the forecasted peak demand for 2015 by the Department of Energy (DOE) at 9,074 MW, at a growth rate of 3.9 percent.

On the other hand, average demand in the region posted an all-time high of 6,623 MW, an increase of 5 percent from last year's 6,307 MW. It is observed that the 5 percent increase in the Luzon 2015 average demand may be influenced by the GDP trend this year, which recorded a 5.8% annual GDP growth driven by stronger domestic attributed to the acceleration in government spending as well as the growth in both public and private investments[2]. Said growth could also be due to the seasonal boost in economic activity in the lead-up to the May 2016 elections.

The increasing trend in electricity demand is illustrated in Figure 1 below, with the year 2010 posting the highest peak demand growth at 9.3 percent (from 6,993 MW in 2009 to 7,644 MW in 2010) while average demand grew by about 10.8 percent (from 5.053 MW to 5,600 MW). The significant growth in demand is influenced by the notable growth in the country's annual Gross Domestic Product (GDP)[3] that year at 7.6 percent, and likewise, by a relatively higher temperature, which averaged at 290C[4]. It is also worthy to mention that election-related spending could have influenced the high GDP that year, considering the conduct of local and national elections in June 2010.

Conversely, the annual GDP for 2011 at 3.6 percent is a notable decline from the annual GDP of 7.6 percent in 2010. This follows the decline in the maximum electricity demand growth that same year by about 2.1 percent. Note however, that this decline could be attributed to the

1 The demand is equal to the total scheduled MW of all load resources for each respective region plus losses.
2 http://www.neda.gov.ph/2016/02/02/statement-of-secretary-balisacan-on-the-2015-fourth-quarter-and-full-year-performance-of-the-philippine-economy-2/
3 The GDP is the basic measure of a country's economic performance.
4 www.weatherunderground.com

realignment of the GDP trend from a very high GDP growth rate in 2010, which was an election year. Meanwhile, the continued growth of the economy may have contributed to the steady increase in electricity demand from years 2012 to 2015. The National Statistical Coordination Board (NCSB), reported that the country's annual GDP grew robustly by about 6.7 percent in year 2012 and 7.1 percent in 2013, and continued to grow though at a slower rate, from years 2014 and 2015 at 6.1 percent and 5.8 percent, respectively.

Similarly, the Visayas region posted a notable 7.3 percent growth in its annual peak demand requirement at 1,684 MW from last year's 1,569 MW. This figure is the highest recorded maximum demand growth in the region since the start of the WESM commercial operations in the Visayas on 26 December 2010.

It is noted that the average demand in the region was sustained at 1,172 MW, similar to the previous year. Drop in minimum demand in year 2013 as shown in Figure 2 is on account of the high outage level in the Visayas on 08 November 2013 due to the destruction of power lines and facilities in the region brought about by typhoon Yolanda.

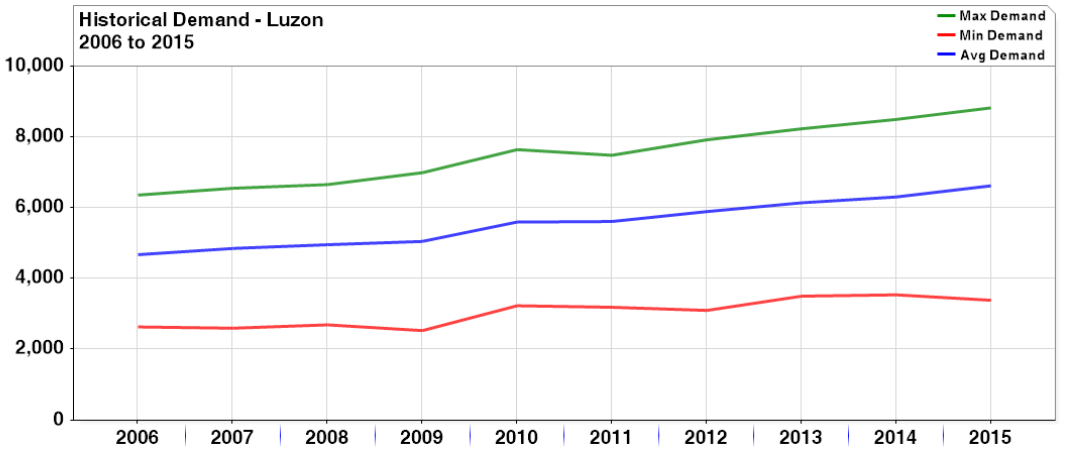

Figure 1 Historical Demand - Luzon

	Annual Demand Growth (MW) - Luzon									
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Max Demand	6,361	6,553	6,658	6,993	7,644	7,485	7,921	8,232	8,497	8,824
Avg Demand	4,678	4,854	4,960	5,053	5,600	5,615	5,895	6,143	6,307	6,623

Table 1 Annual Demand Growth - Luzon

	Demand Growth (% Change) - Luzon								
	2007	2008	2009	2010	2011	2012	2013	2014	2015
Max Demand	3.0	1.6	5.0	9.3	-2.1	5.8	3.9	3.2	3.8
Avg Demand	3.8	2.2	1.9	10.8	0.3	5.0	4.2	2.7	5.0

Table 2 Annual Demand Growth Percent (%) Change - Luzon

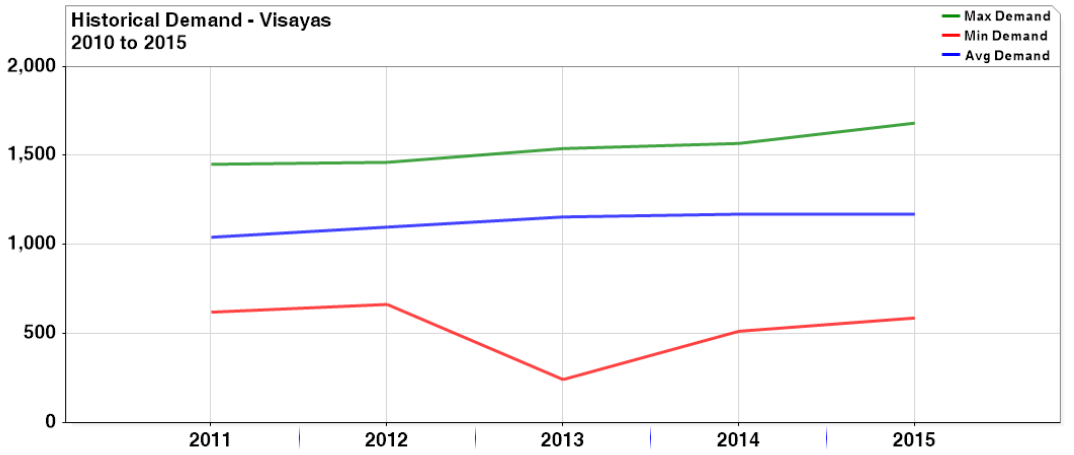

Figure 2 Historical Demand - Visayas

	Annual Demand Growth - Visayas				
	2011	2012	2013	2014	2015
Max Demand	1,452	1,463	1,540	1,569	1,684
Avg Demand	1,042	1,099	1,156	1,172	1,172

Table 3 Annual Demand Growth - Visayas

	Demand Growth (% Change)- Visayas			
	2012	2013	2014	2015
Max Demand	0.8	5.3	1.9	7.3
Avg Demand	5.5	5.2	1.3	0.0

Table 4 Annual Demand Growth Percent (%) Change - Visayas

Demand Profile

Figures 3, 4 and 5 show the hourly demand profiles system-wide, and separately for Luzon and Visayas. These charts illustrate the monthly variation of average hourly demand over the course of a 24-hour period. Note that this year's demand profile demonstrated the same pattern when compared to the previous year, with 3 demand peaks: during the day at 11AM, afternoon at 2PM and evening at 7PM.

System-wide peak demand this year averaged 8,906 MW at 1400H, 8,791 MW at 1100H and 8,728 MW at 1900H. These were higher than the average hourly peak demand recorded in the previous year averaging at 8,706 MW (1400H), 8,657 MW (1100H) and 8,568 MW (1900H). Meanwhile, demand was lowest at 0400H, averaging at 6,426 MW, higher than last year's 6,348 MW.

The demand profile in Luzon mirrored the above pattern, considering that the region accounts for about 85 percent of the total demand system-wide. Demand level during the afternoon peak averagied 7,563 MW at 1400H, higher than the previous year's 7,146 MW.

Similarly, morning and evening demand peak levels went up to 7,462 MW from 7,112 MW in 2014 and 7,314 MW from 7,004 MW in 2014. The region's demand profile illustrates that bulk of the demand requirement in Luzon is attributable to commercial and industrial consumers with high electricity usage during the afternoon work hours.

On the other hand, the Visayas hourly demand peaked at 1,414 MW from last year's 1,401 MW at 1900H. Morning peak was posted at 1,327 MW, slightly lower than the 1,335 MW posted in the previous year, while afternoon demand peaked at 1400H averaging at 1,341 MW, a slight reduction from the 1,344 MW posted in 2014. Nonetheless, the 2015 demand profile in the region is still comparable to the demand profile of the previous year, both of which denotes that majority of the electricity users in the Visayas remains to be the household and commercial end-users, with high energy consumption during the night.

As seen in the charts below, regardless of seasonal changes and varying temperatures throughout the year, the pattern of electricity demand during the course of a day is approximately the same for any given month. However, it must be noted that evening peak demand levels during the November and December billing months were posted at 1800H, instead of 1900H. This noticeable shift may be attributed to the usage of electricity associated with the Christmas festivities during these months.

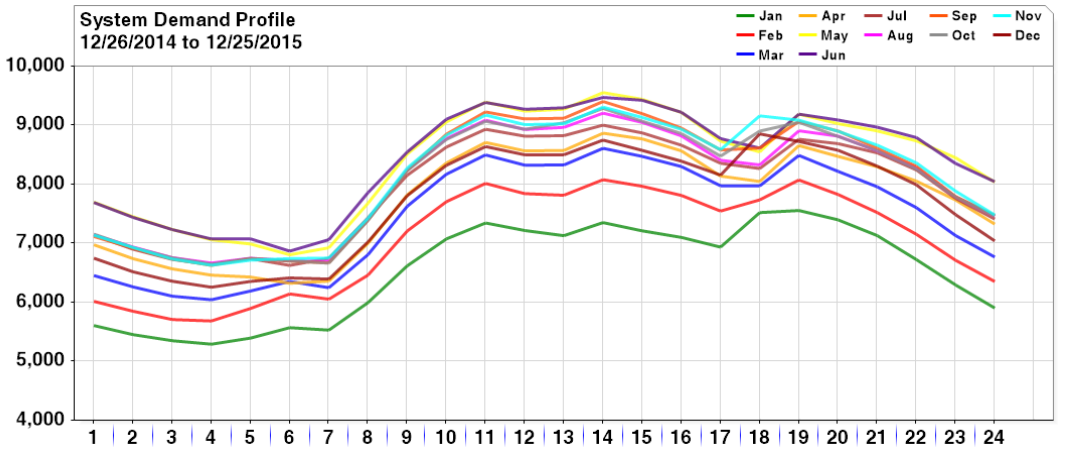

Figure 3 Hourly System Demand Profile

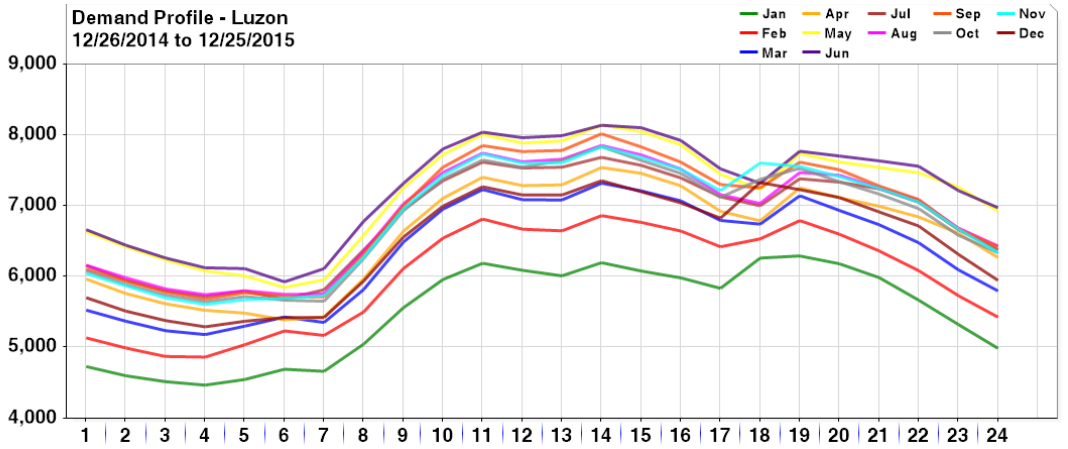

Figure 4 Hourly Demand Profile - Luzon

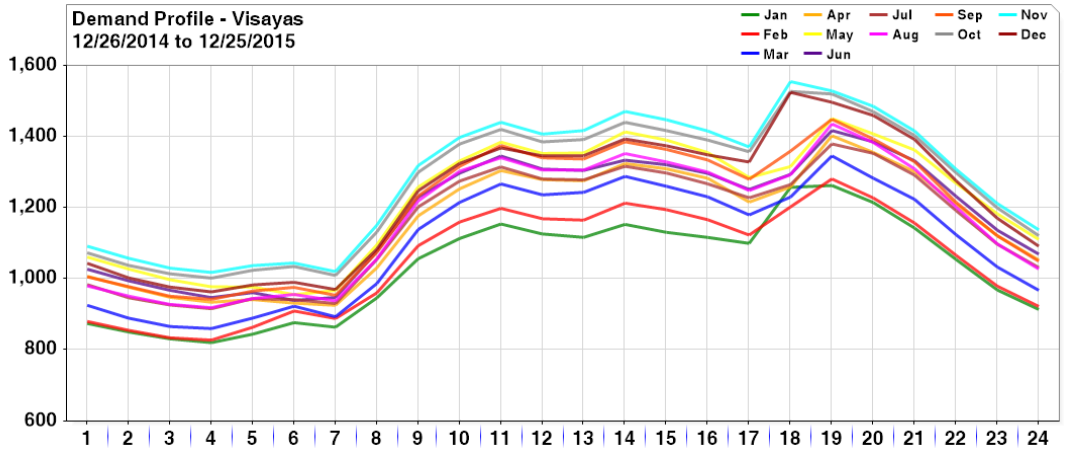

Figure 5 Hourly Demand Profile - Visayas

	Average Demand by Trading Interval (MW), 2015											
	1	2	3	4	5	6	7	8	9	10	11	12
Avg. Demand - Sys	6,907	6,694	6,524	6,426	6,505	6,496	6,508	7,158	7,941	8,468	8,791	8,647
Avg. Demand - Luz	5,911	5,730	5,584	5,497	5,555	5,538	5,565	6,102	6,732	7,188	7,462	7,350
Avg. Demand - Vis	996	964	940	928	949	957	943	1,055	1,207	1,281	1,327	1,295
continuation...	13	14	15	16	17	18	19	20	21	22	23	24
Avg. Demand - Sys	8,662	8,906	8,765	8,568	8,221	8,380	8,728	8,561	8,336	8,042	7,598	7,230
Avg. Demand - Luz	7,364	7,563	7,443	7,275	6,974	7,040	7,314	7,192	7,031	6,838	6,488	6,188
Avg. Demand - Vis	1,296	1,341	1,320	1,292	1,247	1,340	1,414	1,368	1,305	1,204	1,110	1,042

Table 5 Hourly Demand Profile - 2015

	Average Demand by Trading Interval (MW), 2014											
	1	2	3	4	5	6	7	8	9	10	11	12
Avg. Demand - Sys	6,832	6,630	6,448	6,348	6,414	6,378	7,103	7,846	8,385	8,657	8,524	8,524
Avg. Demand - Luz	5,604	5,438	5,290	5,215	5,284	5,294	5,336	5,833	6,427	6,882	7,112	7,006
Avg. Demand - Vis	997	967	944	931	951	955	948	1,065	1,217	1,292	1,335	1,304
continuation...	13	14	15	16	17	18	19	20	21	22	23	24
Avg. Demand - Sys	8,501	8,706	8,552	8,369	8,078	8,230	8,568	8,408	8,301	7,928	7,583	7,132
Avg. Demand - Luz	6,978	7,146	7,028	6,889	6,646	6,738	7,003	6,873	6,805	6,497	6,236	5,858
Avg. Demand - Vis	1,300	1,344	1,315	1,286	1,243	1,330	1,401	1,354	1,282	1,202	1,109	1,041

Table 6 Hourly Demand Profile - 2014

Looking at the quarterly demand trend in 2015, demand levels were largely influenced by the year-round changes in the weather, which are seasonal or predictable to some extent. System-wide, demand peaked during the second quarter of the year driven by the high demand summer months from April to June, and remained relatively high during the 3rd quarter. On the other hand, demand was low during the first quarter of the year due to cooler weather conditions associated particularly with the months of January and February. Drop in demand levels were likewise observed during the 4th quarter, in time for the holiday season as well as the onset of the colder months of November and December. This trend in system-wide demand is mirrored in the demand for energy in the Luzon region. In the Visayas on the other hand, demand followed an increasing trend, with demand reaching its peak during the last quarter of the year and was at its lowest during the 1st quarter.

The Table below provides an indication that although demand is mainly influenced by the seasonal trend in weather and temperature, demand is likewise influenced by the GDP trend, except during the third and fourth quarters, which recorded an increasing GDP growth rate trend for this year. Correspondingly, the highest GDP growth rate was posted during the last quarter, which could be partly due to the seasonal boost in economic activity in the lead-up to the elections. On the other hand, the significant increase in the level of quarterly demand in the second quarter was mirrored in the notable growth rate in GDP during the same period.

Quarter	Avg Quarterly Demand - System (MW)	Avg Quarterly Demand Growth Rate (%)	GDP Growth Rate (%)
1	7,100		5.0
2	8,211	15.6	5.9
3	8,029	(2.2)	6.2
4	7,861	(2.1)	6.5

Table 7 Comparison of Quarterly Average Demand and GDP, 2015

Load Factor[6]

Load factor is a measure of the degree of uniformity of demand over a period of time, and is determined by dividing the total energy withdrawn by the product of the peak load and total numbers of hours in a particular billing period. It is a useful indicator for describing the consumption characteristics of electricity over a period of time.

5 http://www.bworldonline.com/content.php?section=TopStory&title=first-quarter-gdp-growth-surprises&id=127772
6 Computed from the metered quantity of energy withdrawn

As shown in Figure 6 below, no significant month-on-month change was observed in the monthly load factor of the system, which indicates that the load factor for the covered period was steadily averaging at above 70 percent. The same can be said for both the Luzon and Visayas which consistently posted load factors of above 70 percent and 60 percent, respectively.

Year-on-year comparison indicates an improvement in this year's system load factor of 72.4 percent from last year's 69.6 percent, with Luzon registering a high load factor of 72.5 percent from 70.1 percent in 2014. Conversely, load factor in Visayas was slightly lower at 62.6 percent from last year's 63.5 percent.

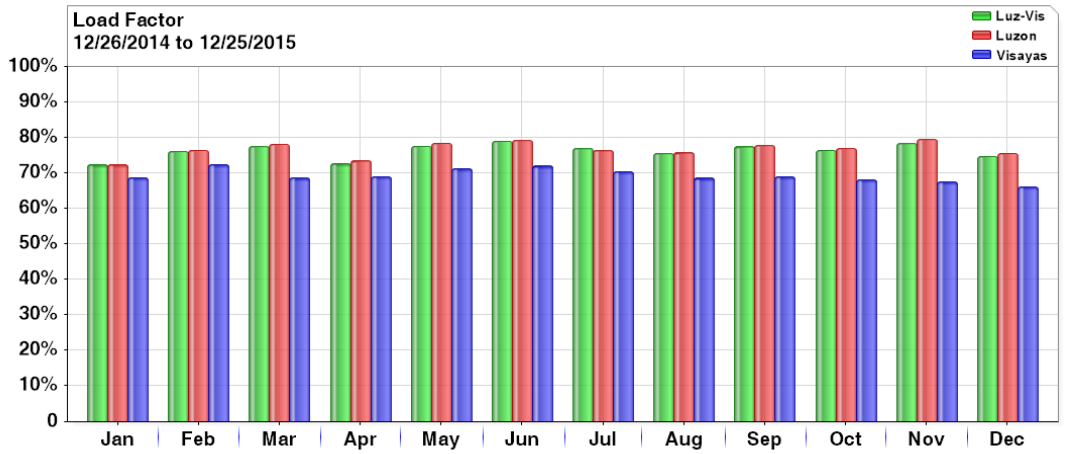

Figure 6 System Load Factor

	Load Factor (%) by Billing Month, 2015												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Avg
System	72.4	76.0	77.5	72.7	77.6	79.0	76.8	75.4	77.4	76.4	78.3	74.7	72.4
Luzon	72.5	76.4	78.1	73.4	78.4	79.2	76.3	75.6	77.7	76.9	79.4	75.5	72.5
Visayas	68.7	72.4	68.6	69.0	71.2	72.0	70.4	68.5	68.9	68.1	67.5	66.1	62.6

Table 8 Monthly Load Factor - 2015

	Load Factor (%) by Billing Month, 2014												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Avg
System	85.4	85.9	89.0	74.6	77.1	76.6	72.4	74.5	76.1	78.0	76.3	74.0	69.6
Luzon	74.0	74.7	76.9	75.7	77.7	77.4	72.3	75.3	77.3	79.0	77.4	74.1	70.1
Visayas	62.6	64.4	67.9	66.2	71.4	70.6	69.2	66.9	67.4	68.7	68.5	67.0	63.5

Table 9 Monthly Load Factor - 2014

LOAD FORECAST VARIATION

The load forecast variation compares the ex-ante load schedule and the ex-post load, and intends to measure the level of accuracy of the load forecast in the ex-ante from the actual load in the ex-post.

Load forecasts this year generally improved when compared to billing year 2014. In both regions for billing year 2015, bulk of the variation between the ex-ante and the ex-post load fell within the +/-3 percent, at 97.1 percent in Luzon and 91.6 percent in Visayas. When compared to the previous year, only 72.7 percent of the load forecast in Luzon and only 44.1 percent of the load forecast in the Visayas fell within +/-3 percent

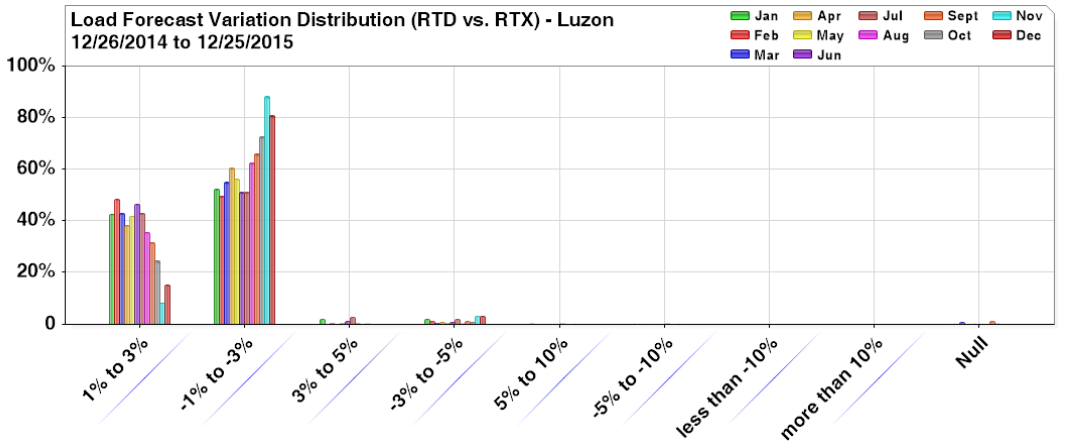

Figure 7 Load Forecast Variation Distribution (Ex-Ante vs. Ex-Post) - Luzon

	Load Factor Variation (%) Distribution (RTD vs RTX) - Luzon, 2015												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Avg
Less than -10%	-	-	-	-	-	-	-	-	-	-	-	-	-
-5% to -10%	0.3	0.1	-	0.1	0.1	-	0.6	0.3	-	0.3	-	-	0.3
-3% t0 -5%	2.0	1.1	0.7	0.8	0.7	0.8	2.1	0.5	1.1	1.0	3.1	3.2	1.4
-1% to -3%	52.4	49.6	54.9	60.5	65.4	51.1	51.1	62.5	65.9	72.6	88.3	80.8	62.2
1% to 3%	42.7	48.5	42.9	38.2	41.9	46.6	42.9	35.6	31.6	24.7	8.3	15.4	35.0
3% to 5%	1.9	0.4	0.6	0.4	0.7	1.1	2.6	0.7	0.4	0.6	0.3	0.4	0.8
5% to 10%	0.5	-	-	-	-	0.1	0.6	0.3	-	0.3	-	-	0.4
More than 10%	-	-	-	-	-	-	-	-	-	-	-	-	-
Null	0.1	0.3	0.9	-	0.1	0.3	0.1	0.1	1.1	0.6	-	0.1	0.4

Table 10 Load Forecast Variation Distribution (Ex-Ante vs. Ex-Post) - Luzon

Note: Results are null if either the ex-ante or the ex-post load forecast is null due to market intervention/suspension.

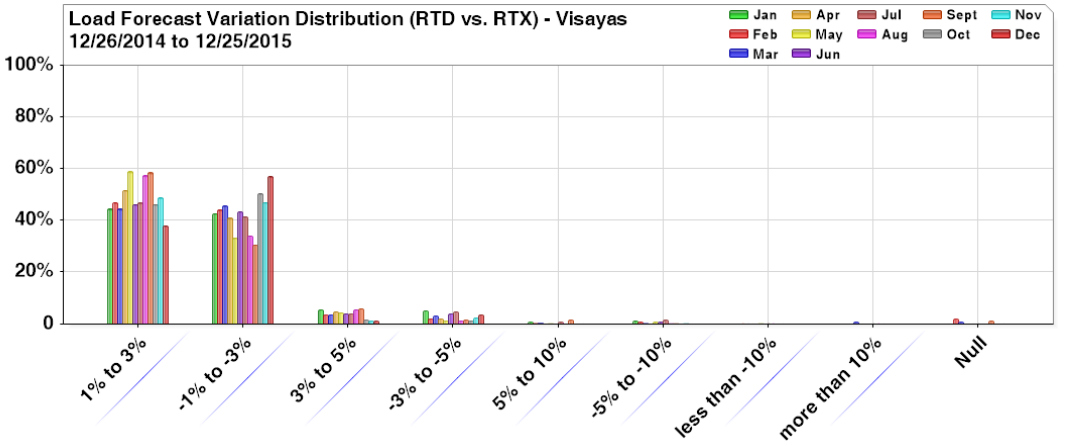

Figure 8 Load Forecast Variation Distribution (Ex-Ante vs. Ex-Post) - Visayas

	Load Factor Variation (%) Distribution (RTD vs RTX) - Visayas, 2015												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Avg
Less than -10%	-	0.3	0.1	0.1	0.6	0.4	0.3	0.3	0.1	0.1	-	-	0.3
-5% to -10%	1.2	0.8	0.6	0.4	0.8	0.9	1.5	0.5	0.5	0.1	0.5	0.1	0.7
-3% t0 -5%	5.2	1.9	3.3	2.0	1.3	3.9	4.9	1.3	1.5	1.3	2.4	3.5	2.7
-1% to -3%	42.7	44.1	45.7	40.9	33.2	43.5	41.5	34.1	30.6	50.4	47.0	57.1	42.6
1% to 3%	44.4	46.9	44.3	51.7	58.9	46.2	46.8	57.4	58.5	46.3	48.8	37.9	49.0
3% to 5%	5.4	3.5	3.4	4.7	4.4	4.0	3.8	5.6	5.9	1.7	1.1	1.1	3.7
5% to 10%	0.9	0.7	0.7	0.1	0.6	0.4	1.0	0.3	1.5	0.1	0.1	0.1	0.5
More than 10%	-	-	0.9	-	0.1	0.4	0.1	0.3	0.1	-	-	-	0.3
Null	0.1	1.9	0.9	-	0.1	0.1	0.1	0.1	1.2	-	-	0.1	0.5

Table 11 Load Forecast Variation Distribution (Ex-Ante vs. Ex-Post) - Visayas

Note: Results are null if either the ex-ante or the ex-post load forecast is null due to market intervention/suspension.

SUPPLY PROFILE

Sustained growth in the total WESM registered capacity was observed this year with the entry of twenty-one (21) new generating units (see Table 14) with a combined capacity of 984.3 MW. While most of these are preferential dispatch plants, the share of conventional generation facilities in terms of MW capacity remain large. It is noted that the combined capacity of coal and natural gas plants were posted at 614 MW, while new preferential dispatch plants comprising of biofuel, solar and wind plants accounted for 256 MW. The remaining additional capacities were attributable to the entry of new oil-based and hydro plants at 100 MW and 14.3 MW, respectively.

Expansion of some conventional plants were also observed this year with the increase in the registered capacity of the following plants: geothermal plant Bacman 1 (from 115 MW to 120

MW in March), oil-based plant Panay DPP III (from 52 MW to 57 MW in March), hydro plant Binga 1,2,3,4 (from 33 MW each to 35 MW per unit in May), oil-based plant TPC (Sangi) (from 60 MW to 145 MW in September) and hydro plant San Roque 1,2,3 (from 137 MW to 145 MW per unit in November). NWIND likewise posted an increase in its WESM registered capacity from 27 MW to 33 MW in February.

By the end of year 2015, the total WESM registered capacity already stood at 16,140 MW, higher by 9.3 percent from the yearend figure in 2014, posted at 14,760 MW. Other changes in the WESM registered capacities of certain plants were also noted during the billing year, including the adjustment in the registered capacity of SLTEC 1 from 135 MW to 120.6 MW in February, as well as the removal of the 95 MW coal-fired unit of SPC Power Corporation following the deregistration of said generating unit from the WESM effective 24 May.

Of the total WESM registered capacity, only about 60 percent or an average of 9,450 MW was offered in the market during the year. About 12.9 percent was unavailable due to plant outages, posted at 2,019 MW while about 14.9 percent were not offered, due to 2,344 MW. Nevertheless, more capacities were made available this year, marked with a moderate 4.1 percent increase in the average offered capacity from last year's 9,076 MW to 9,450 MW in the current year. On the other hand, outage capacity declined by 4.0 percent from 2,103 MW, while capacity not offered rose by 5.2 percent from last year's 2,228 MW.

About 5.9 percent averaging at about 928 MW corresponded to ancillary services which were scheduled by the System Operator to provide regulating, contingency and dispatchable reserves. Meanwhile, the MRU designation of oil-based plant Malaya comprised 2.6 percent, averaging at 409 MW, while the available capacities for non-scheduled generation accounted for the remaining 3.8 percent of the WESM registered capacity, averaging at about 606 MW. It is observed that the capacities scheduled for ancillary services increased by about 20.5 percent from last year's average of 770 MW. Also, increased availability of oil-based Malaya was observed this year, particularly from Malaya 1, which remained on outage for the most part of 2014. Further, non-scheduled generation[7] likewise grew significantly from an average of 157 MW in 2014.

The increasing trend of non-scheduled generation in the market was observed following the steady increase in the entry of new preferential dispatch generation units during the billing year. The December billing month recorded the highest available capacity from non-scheduled generation, averaging at 727 MW. Wind plants, which contributed about 427 MW in the market, topped the list among the registered non-scheduled generating units in the WESM, followed by biomass plants, with its combined registered capacity of about 149 MW; solar plants, with about 111 MW; and hydro plants, contributing about 37 MW of the total WESM registered capacity by the end of billing year 2015.

Note that trading intervals marked with market intervention events during the billing year were excluded from the system-wide and/or regional Supply Profiles, as shown in the succeeding Figures below.

7 Non-scheduled generation refers to the system-wide combined capacities of non-scheduled, priority dispatch and must dispatch generating units.

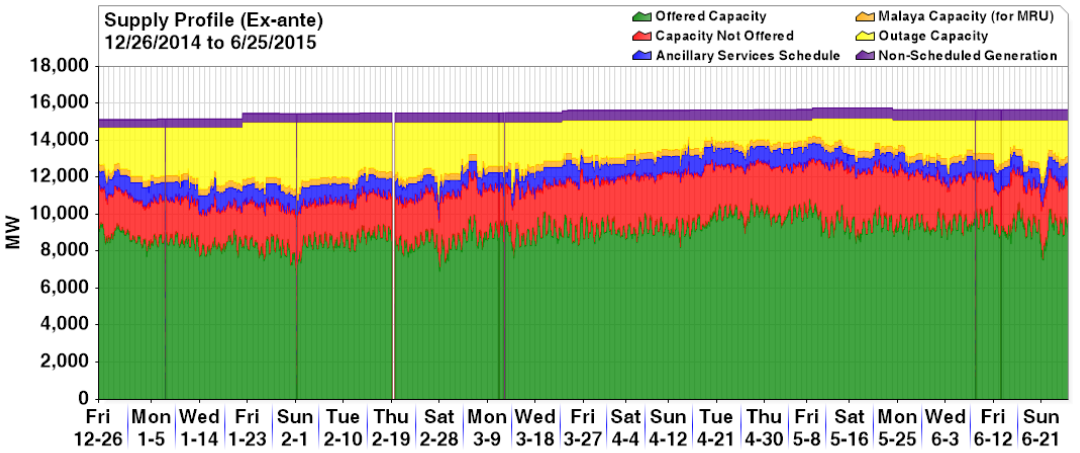

Figure 9 Supply Profile - 1st Half

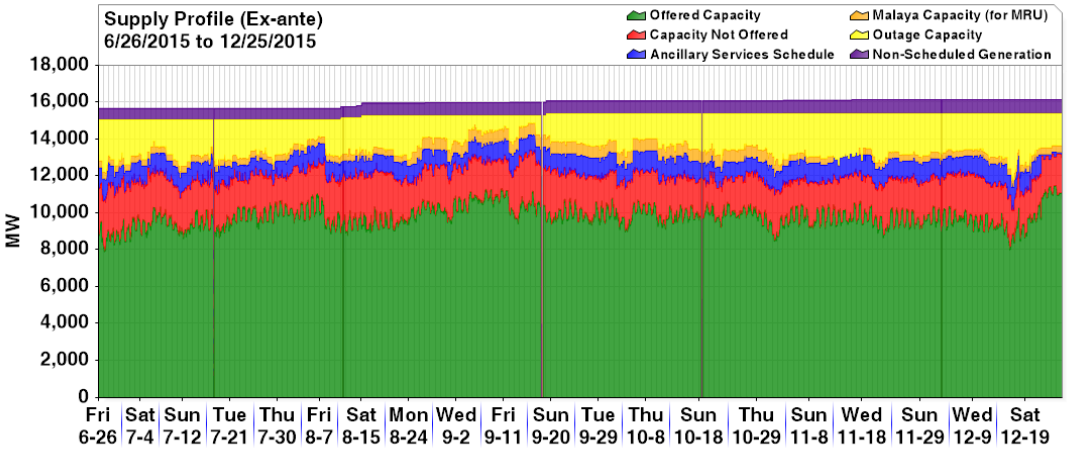

Figure 10 Supply Profile - 2nd Half

	Supply Profile by Billing Month (MW) - 2015						
	Jan	Feb	Mar	Apr	May	Jun	Jul
Registered Capacity (End of Month)	15,469	15,467	15,635	15,659	15,666	15,666	15,959
Avg. Offered Capacity	8,564	8,477	8,869	9,407	9,723	9,424	9,383
Avg. Outage Capacity	2,722	2,976	2,383	1,632	1,327	1,969	2,079
Avg. Capacity Not Offered	2,149	2,259	2,529	2,766	2,860	2,420	2,282
Avg. Ancillary Services Schedule	936	902	860	912	860	890	968
Avg. Malaya Capacity (for MRU)	350	350	350	350	350	350	354
Avg. Non-Scheduled Generation	474	506	51	563	590	594	594
continuation...	Aug	Sep	Oct	Nov	Dec	Annual Avg	
Registered Capacity (End of Month)	15,959	16,081	16,82	16,140	16,140	15,750	
Avg. Offered Capacity	9,780	10,342	9,922	9,720	9,758	9,450	
Avg. Outage Capacity	1,779	1,141	1,771	2,238	2,220	2,019	
Avg. Capacity Not Offered	2,348	2,250	2,038	2,069	2,176	2,344	
Avg. Ancillary Services Schedule	919	938	1,011	1,020	918	928	
Avg. Malaya Capacity (for MRU)	369	650	650	432	350	409	
Avg. Non-Scheduled Generation	617	680	692	703	727	606	

Table 12 Supply Profile - System

New Plants Registered in the WESM, 2015				
Region	Plant Type	Plant Name	Registered Capacity (MW)	Effective Registration Date
LUZON	BIOF	2020 Biomass	13	May 06, 2015
		MMPC Biomas	5.1	August 13, 2015
		IBEC Biomas	18	August 27, 2015
		PGEP Biogas	0.8	October 09, 2015
	COAL	SLPGC CFTPP 1	150	January 22, 2015
		SLPGC CFTPP 2	150	January 22, 2015
		ANDA CFTPP	82	May 09, 2015
		SLTEC CFTPP	135	August 15, 2015
	HYD	Sabangan HEP	14.3	April 16, 2015
	NATG	Avion NGPP	97	August 11, 2015
	OIL	Millenium GTPP	100	March 23, 2015
	SOLR	MEC Solar	32.9	January 06, 2015
		Burgos SOlar	3.7	March 24, 2015
		RASLAG Solar	10	April 23, 2015
		SM North Solar	1.22	August 13, 2015
	WIND	Pililia Wind	54	August 14, 2015
VISAYAS	BIOF	HPCO Biomass	3	January 06, 2015
		VMC Biomass	34	November 16, 2015
	SOLR	PSFLI Solar	24.48	March 24, 2015
		San Carlos Solar	19.8	September 12, 2015
	WIND	PWEI Nabas Wind	36	February 13, 2015

Table 13 New Power Plants

Registered capacity in Luzon mirrored the system-wide supply profile, increasing by about 4.6 percent from last year's 12,591 MW. As already discussed, this growth is influenced by the entry of additional capacities in the market as well as the above-mentioned adjustments in the registered capacities of existing plants.

About 59.3 percent of the WESM registered capacity in the region was offered in the market, averaging at 7,983 MW. Meanwhile, 13.9 percent was attributed to outage capacity, which for the year averaged at 1,863 MW, while 14.6 percent is on account of capacity not offered, averaging at 1,966 MW. When compared with the previous year, offered capacity grew by 4.6 percent from an average of 7,630 MW. On the other hand, outage capacity denoted a 3.2 percent decrease from an average of 1,925 in 2014, while capacity not offered slightly grew by 0.7 percent from last year's 1,953 MW.

On the other hand, about 6.4 percent or an average of 857 MW was allocated for the provision of ancillary services, while 3.0 percent averaging at 480 MW corresponded to the designation of Malaya as MRU. The remaining 2.9 percent or 396 MW was attributed to non-scheduled generation[8]. These were noted to have significantly increased when compared to the previous year, as follows: ancillary services schedule by 16.2 percent from an average of 738 MW; Malaya capacity for MRU by 8.5 percent from 376 MW in 2014; and non-scheduled generation by 370 percent from an average of 84 MW.

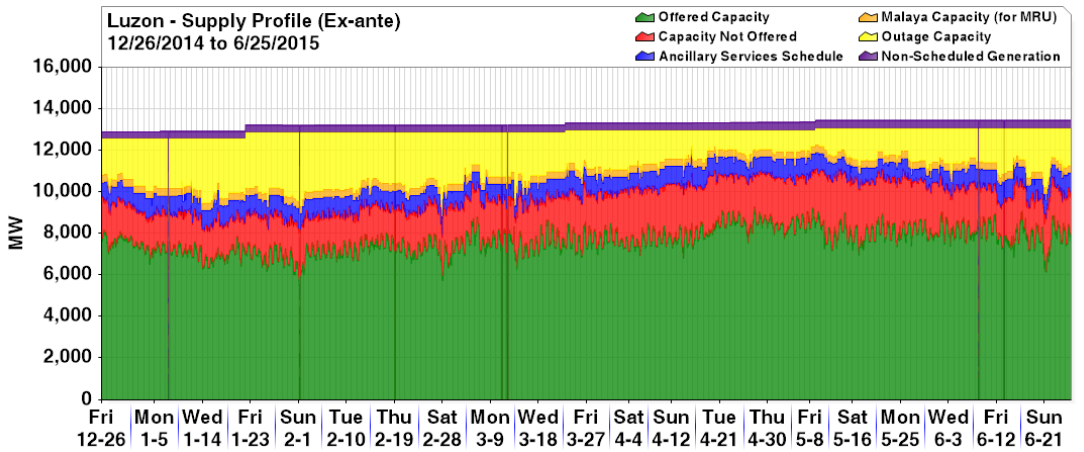

Figure 11 Supply Profile (Luzon) - 1st Half

8 Non-scheduled generation refers to the combined capacities of non-scheduled, priority dispatch and must dispatch generating units in the Luzon region.

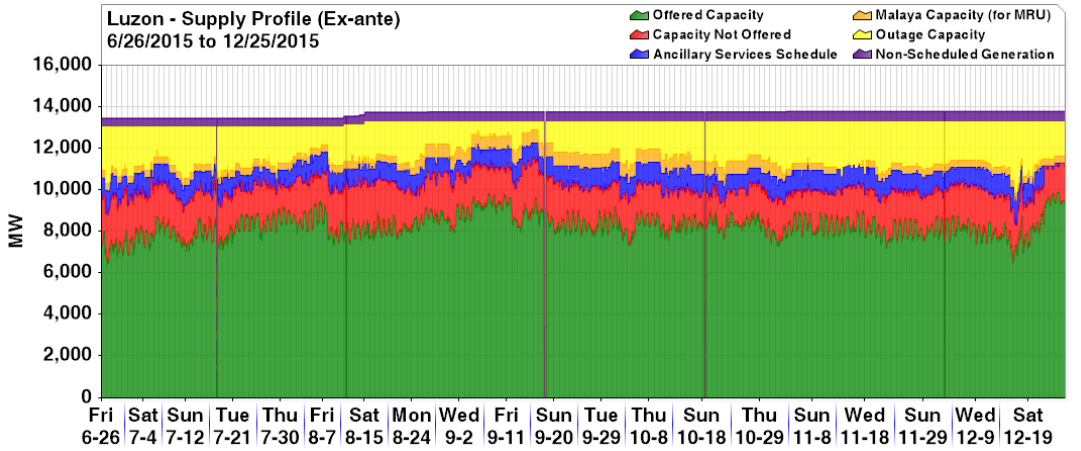

Figure 12 Supply Profile (Luzon) - 2nd Half

	Supply Profile by Billing Month (MW) - Luzon, 2015						
	Jan	Feb	Mar	Apr	May	Jun	Jul
Registered Capacity (End of Month)	13,221	13,213	13,322	13,346	13,448	13,448	13,448
Avg. Offered Capacity	7,218	7,154	7,535	7,929	8,229	8,015	7,844
Avg. Outage Capacity	2466	2,709	2,159	1,503	1,184	1,783	1,995
Avg. Capacity Not Offered	1,712	1,818	2,039	2,331	2,460	2,067	1,968
Avg. Ancillary Services Schedule	871	838	805	851	800	833	896
Avg. Malaya Capacity (for MRU)	350	350	350	350	350	350	354
Avg. Non-Scheduled Generation	324	340	342	351	378	382	382
continuation...	Aug	Sep	Oct	Nov	Dec	Annual Avg	
Registered Capacity (End of Month)	13,740	13,758	13,759	13,783	13,783	13,783	
Avg. Offered Capacity	8,308	8,806	8,328	3,213	8,205	7,983	
Avg. Outage Capacity	1,639	1,041	1,695	2,75	2,124	1,863	
Avg. Capacity Not Offered	2,023	1,936	1,699	1,720	1,830	1,966	
Avg. Ancillary Services Schedule	848	857	826	842	817	857	
Avg. Malaya Capacity (for MRU)	369	650	650	432	350	408	
Avg. Non-Scheduled Generation	405	460	461	461	461	396	

Table 14 Supply Profile - Luzon

At the end of the billing year, the total WESM registered capacity in the Visayas stood at 2,277 MW, an increase by about 5.9 percent from last year's 2,150 MW. About 64.4 percent of which accounted for the region's offered capacity, at an average of 1,466 MW. Unavailable capacities registered at 6.8 percent and 16.7 percent, respectively, accounting for average outage capacity at 155 MW and capacity not offered at 380 MW. On the other hand, 3.1 percent or 71 MW is attributable to ancillary services while the remaining 9.2 percent or 210 MW, is on account of non-scheduled generation[9].

When compared to the previous year, capacity offered in the Visayas slightly increased by 0.81 percent from 1,455 MW. Outage capacity demonstrated an increase by 5.2 percent from

9 Non-scheduled generation refers to the combined capacities of non-scheduled, priority dispatch and must dispatch generating units in the Visayas region.

148 MW, while capacity not offered declined by 14.2 percent from 443 MW. Ancillary services schedule and non-scheduled generation both registered significant growth by 46.3 percent and 252.7 percent, respectively, from 49 MW and 60 MW in 2014.

Drop in the region's registered capacity was observed with the deregistration from the WESM of the 95 MW coal-fired generating units of SPC Power Corporation effective 24 May 2015. Nevertheless, registered capacity in the Visayas continued to grow with the entry of new generating units, particularly during the September and November billing months (as shown in Table 12), as well as the increase in the registered capacity of coal plant TPC (Sangi) from 60 MW to 145 MW in September.

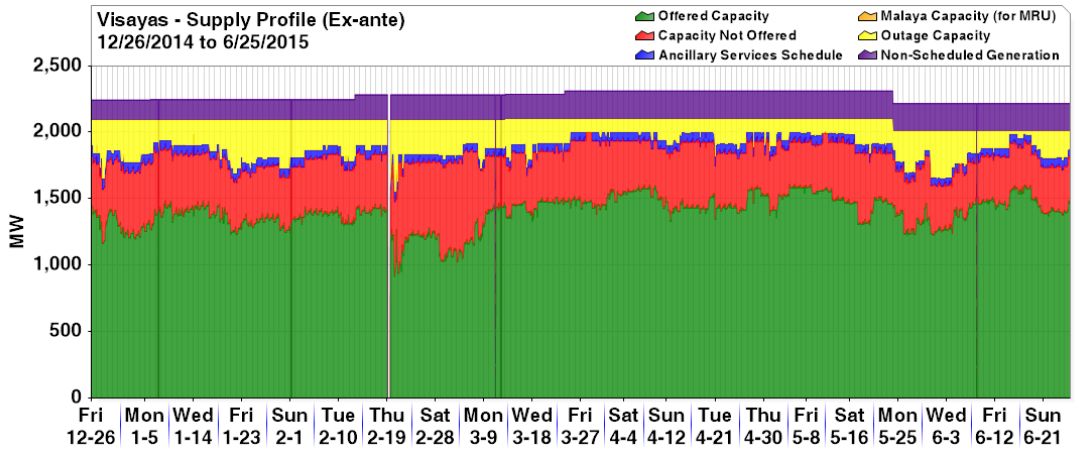

Figure 13 Supply Profile (Visayas) - 1st Half

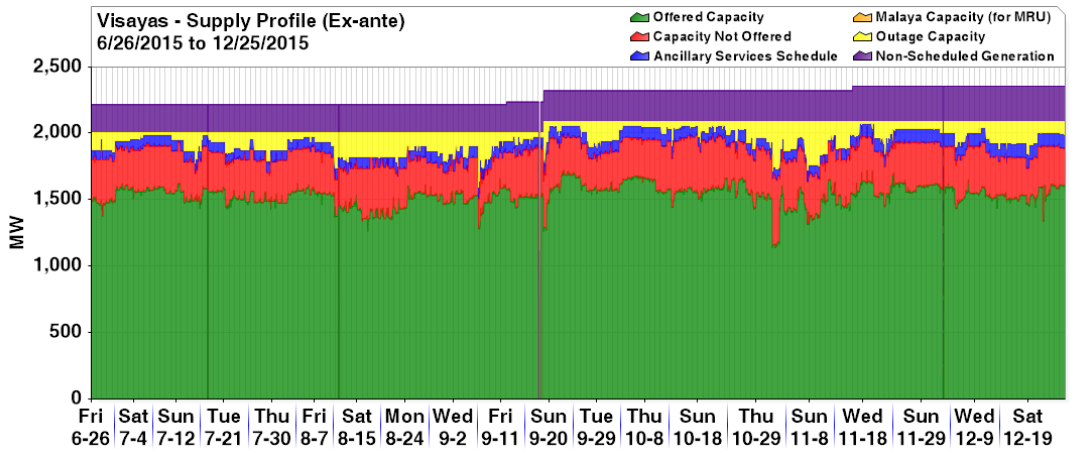

Figure 14 Supply Profile (Visayas) - 2nd Half

	Supply Profile by Billing Month (MW) - Visayas, 2015						
	Jan	Feb	Mar	Apr	May	Jun	Jul
Registered Capacity (End of Month)	2,248	2,248	2,313	2,313	2,218	2,218	2,218
Avg. Offered Capacity	1,346	1,326	1,334	1,478	1,494	1,409	1,539
Avg. Outage Capacity	267	223	129	143	186	84	
Avg. Capacity Not Offered	437	449	490	435	399	356	314
Avg. Ancillary Services Schedule	65	64	56	63	62	57	72
Avg. Non-Scheduled Generation	150	166	189	212	212	212	212
continuation...	Aug	Sep	Oct	Nov	Dec	Annual Avg	
Registered Capacity (End of Month)	2,218	2,323	2,323	2,357	2,357	2,277	
Avg. Offered Capacity	1,477	1,536	1,594	1,507	1,553	1,466	
Avg. Outage Capacity	140	100	76	163	96	155	
Avg. Capacity Not Offered	325	315	348	350	347	380	
Avg. Ancillary Services Schedule	71	81	85	77	101	71	
Avg. Non-Scheduled Generation	212	221	232	242	266	210	

Table 15 Supply Profile - Visayas

DEMAND AND SUPPLY

DEMAND[10] AND SUPPLY[11] SITUATION

Changes in the demand levels this year are generally predictable and followed seasonal patterns. Steady increase in the level of system demand was observed particularly during the first half of the year, coming from a low demand season at the beginning of the year due to colder temperature levels. Significant demand growth was posted during the summer months, demonstrated by the increase of about 8.3 percent in average demand from 7,741 MW in April to an average of 8,381 MW in May. It was further observed that hourly demand levels in May exhibited increases even during the evening off-peak hours. Peak demand reached an all-time high of 10,337 MW on 21 May at 1400H. While such growth was sustained through the June billing month, seasonal decline in the demand level was noted beginning July, marked with a 5.4 percent decrease in the monthly average demand level from 8,407 MW in June to 7,952 MW. No significant change in the monthly system demand was noted during the second half of the year, except for the month of December when demand levels dropped to 7,804 MW attributed to the holiday season and colder weather temperatures. Demand was particularly low during the last week of December billing month.

As shown in the Figures below, the seasonal characteristic of demand strongly influenced the demand pattern during certain periods of the year. Demand levels dropped due to cooler weather conditions during the first week of the billing year and also plunged during the declared holidays from 15 to 19 January (Papal visit to the Philippines), 2 to 4 April (Holy Week), on 9 April (“Araw ng Kagitingan”), 21 to 24 August when a nonworking holiday was declared in the country in view of the Ninoy Aquino Day, and during the observance of All Saints Day and All

10 The system effective supply is equal to the offered capacity of all generator resources adjusted for any security limit provided by SO and other constraints considered during the market dispatch optimization process such as generator offered ramp rates.

11 System demand is equal to the total scheduled MW of all load resources in Luzon and Visayas plus losses.

Souls Day on 01 and 02 November. Further dips in demand were recorded on 06 to 10 July 2015 due to Typhoon Egay and Typhoon Falcon which consecutively hit the country during the period, and on 17 to 20 October due to Typhoon Lando which particularly hit the northern part of Luzon.

On the other hand, effective supply levels indicated a modest increase by about 2.8 percent from an average of 8,936 MW in the previous year to 9,190 MW. Though effective supply growth was modest this year, supply availability during periods with projected low supply levels as well as the high-demand summer season notably improved when compared to last year.

The lowest monthly effective supply level was posted during the January and February billing months, averaging at 8,175 MW and 8,147 MW, respectively, when demand levels were also low. The high outage level during these months was driven by the high incidence of planned outages among the large generating coal plants. High outage capacity continued to drive supply levels down until the first half of the March billing month. Consequently, moderate increase in the effective supply level averaging at 8,625 MW was observed in March. Another contributing factor is the shutdown of SPEX Malampaya Onshore Natural Gas Plant which commenced as scheduled on 15 March 2015, cutting-off the supply of natural gas to plants Ilijan, Sta. Rita and San Lorenzo. The Sta. Rita and San Lorenzo units ran at full capacity on alternate liquid fuel from 15 March, except during periods when units went on forced outages. Also around this time, only Ilijan Block A was running using B2 fuel (diesel blended with 2% biodiesel), but at limited capability. Nevertheless, the weeks coinciding with the Malampaya shutdown posted better supply conditions, averaging at 8,846 MW, than the weeks prior to the shutdown when supply averaged at only 8,481 MW. As already mentioned, high outage capacity prior to the Malampaya shutdown was observed to be mainly on account of the outages of major coal plants, most of which went back online during the second half of the March billing month (see Chapter on Outage). SPEX Malampaya resumed normal operations on 12 April resulting in higher supply levels and wider supply margins during the April billing month.

Effective supply continued to increase through May, at an average of 9,589 MW, but begun to post a decline beginning June, averaging at 9,253 MW. Supply crept further down in July at 9,137 MW. Notwithstanding these increases, narrow supply margins prevailed in May and June, averaging at 1,209 MW and 635 MW, respectively, mainly on account of the higher demand requirement associated with the summer months. On the other hand, the July to September billing months followed an increasing supply trend due to the fewer plant outages during these months. However, as more plants went on outage during the 4th quarter of the year, corresponding decrease in the level of supply was likewise noted during this period.

Significant increase in supply was observed in the last part of the December billing month attributable to the increase in capacity offers from generator-trading participants. It may be recalled that the central scheduling and dispatch of energy and contracted reserves in the WESM (for the Luzon region only) was implemented effective 22 December 2015. This required all generator trading-participants with ERC-approved Ancillary Services Procurement Agreement (ASPA) to submit their reserve offers to the market corresponding to the day-ahead ancillary service schedule approved by the System Operator (SO).

Supply margins widened during the last week of the year as demand levels dropped during the holiday season while effective supply levels grew, with posted increase in the capacity offers in the market during the period. Wide supply margins were likewise observed coinciding with the significant dips in demand during the first week of the billing year, the observance of the Holy Week in April and the Ninoy Aquino holiday in August. Overall, average supply margin widened by about 10.3 percent to 1,386 MW from 1,257 MW in the previous year.

The maximum supply level was reached on 04 September at 1500H, posted at 11,194 MW while the minimum supply level was posted at 6,574 MW on 01 February at 0400H.

Note that the market was suspended in the Visayas from 08 November 2013 at 1500H to 25 March 2014 at 2400H due to the destruction of the Visayas power system by the passage of typhoon Yolanda. Hence, year-on-year comparison of the system-wide supply and demand covered only the April to December 2014 billing months as shown in Table 18.

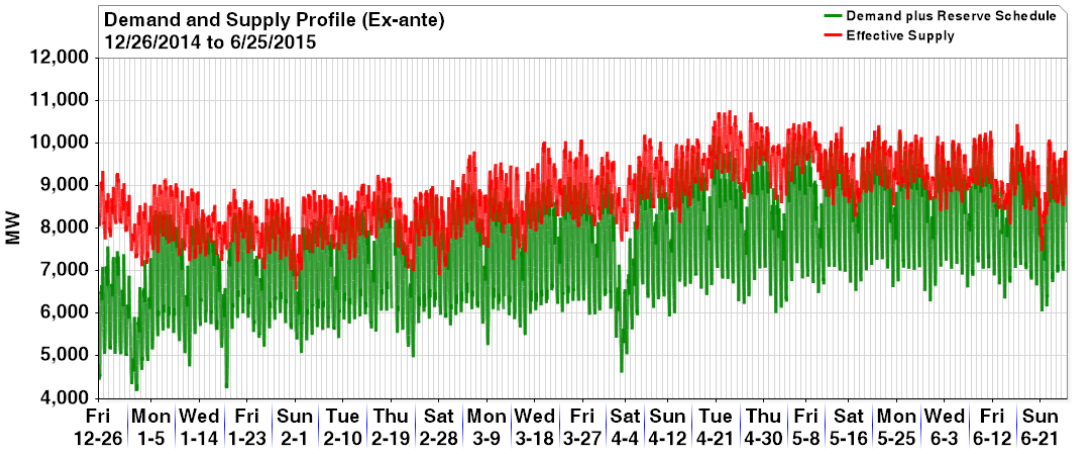

Figure 15 Demand and Effective Supply, 2015 - 1st Half

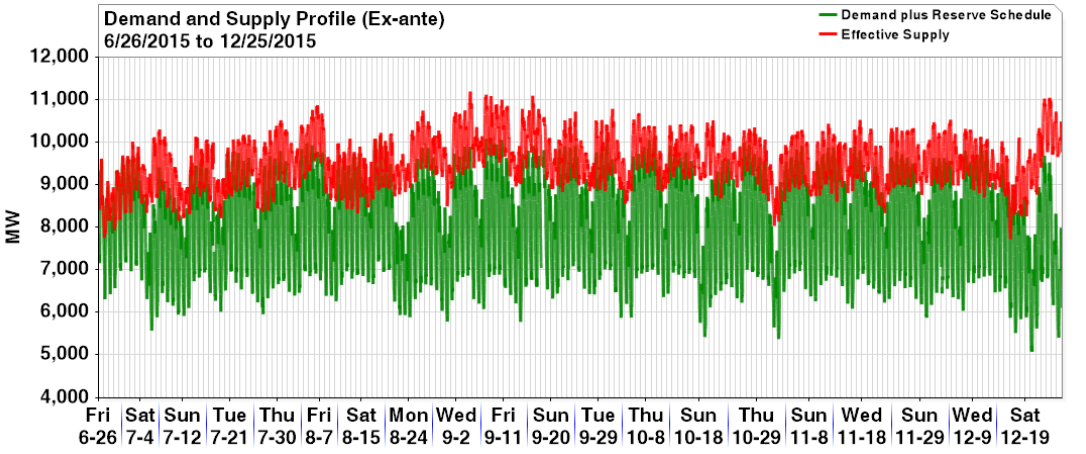

Figure 16 Demand and Effective Supply, 2015 - 1st Half

	Sumary of Demand and Supply (MW) - 2015						
	Jan	Feb	Mar	Apr	May	Jun	Jul
Avg. Demand	6,528	7,051	7,462	7,741	8,381	8,407	7,952
Avg. Effective Supply	8,175	8,147	8,625	9,264	9,589	9,253	9,137
Avg. Supply Margin	1,647	1,096	1,164	1,523	1,209	845	1,185
continuation...	Aug	Sep	Oct	Nov	Dec	Annual Avg	
Avg. Demand	8,027	8,106	8,058	8,119	7,804	7,804	
Avg. Effective Supply	9,477	9,913	9,633	9,466	9,566	9,190	
Avg. Supply Margin	1,450	1,807	1,574	1,347	1,761	1,386	

Table 16 Demand and Supply Summary - 2015

	Sumary of Demand and Supply (MW) - 2014				
	Apr	May	Jun	Jul	Aug
Avg. Demand	7,528	8,205	8,098	7,818	7,545
Avg. Effective Supply	8,485	9,225	8,998	8,500	8,878
Avg. Supply Margin	956	1,020	900	683	1,333
continuation...	Sep	Oct	Nov	Dec	Annual Avg
Avg. Demand	7,478	7,583	7,562	7,327	7,679
Avg. Effective Supply	8,863	9,090	9,060	9,214	8,936
Avg. Supply Margin	1,384	1,506	1,499	1,887	1,257

Table 17 Demand and Supply Summary - 2014

Meanwhile in Luzon, the decline posted in the monthly average effective supply[12] in January and February drove the 10.1 percent overall decrease in the region's average effective supply for 2015, which averaged at 6,631 MW from last year's 7,377 MW. The January and February billing months recorded the lowest monthly average supply throughout the year, at 6,811 MW and 6,809 MW, respectively, from an average of 7,104 MW and 7,284 MW in the previous year. The low supply levels during these months were attributable to the high level of outage capacity, mostly contributed by large generating plants which were mostly on planned outage in said months. Note however, that most of these unavailable plants were able to resume operations by mid-March. Consequently, higher supply levels were recorded from March to June 2015. This notwithstanding, driven by the higher demand[13] level during the summer months, supply margin narrowed in May and June, averaging at 939 MW and 625 MW, respectively, the latter incurring the most narrow monthly average supply margin this year in the Luzon region. Demand in Luzon during the summer months averaged at 6,356 MW in March, 6,582 MW in April, 7,160 MW in May and 6,970 MW in June, when the average monthly demand level in the region reached its peak.

Year-on-year comparison of monthly supply levels from March to June showed that more capacities became available this year when compared to the previous year, while supply margins were likewise wider this year, except for the June billing month which obtained a 1.6 percent decline from last year's average supply margin of 635 MW.

12 The regional effective supply is equal to the offered capacity of all generator resources in each region adjusted for any security limit provided by the System Operator and other constraints considered during MMS simulation such as generator offered ramp rates, excluding the HVDC import/export.

13 The regional demand is equal to the total scheduled MW of all load resources for each respective region plus losses.

Moving further, the billing month of July demonstrated a decline from 7,848 MW in June to 7,606 MW in its average effective supply, as tight supply conditions were observed more frequently, in part due to the month-long planned outage of Ilijan A (Units 2 and 3) and the series of unavailability among natural gas plants due to the Malampaya gas restriction this month. Furthermore, low supply levels were likewise observed on 20 July at 1900H and 21 July at 1100H triggered by the unavailability of coal plants QPPL, Pagbilao and Calaca 2.

Effective supply from August to October followed an increasing trend, with the September billing month obtaining the highest effective supply level for the year at an average of 8,401 MW, resulting in wider supply margins during the period. Drop in the level of demand was observed in November and December, though a slightly higher average effective supply in December at 8,019 MW coming from 7,975 MW in November was recorded following the implementation of the central scheduling in the region. This was also higher than previous year's 7,789 MW.

Observations from the exchange of power between the Luzon and Visayas regions through the HVDC Interconnection showed that Luzon is importing power from the Visayas majority of the time, particularly during off-peak hours. Increase in the frequency of the power flow from Visayas to Luzon was observed during the February and July billing months, in time with the tight supply conditions in the region during these months. Note that the HVDC Interconnection was unavailable for 72 trading intervals, from 14 to 17 December when the HVDC tripped due to the onslaught of Typhoon Nona.

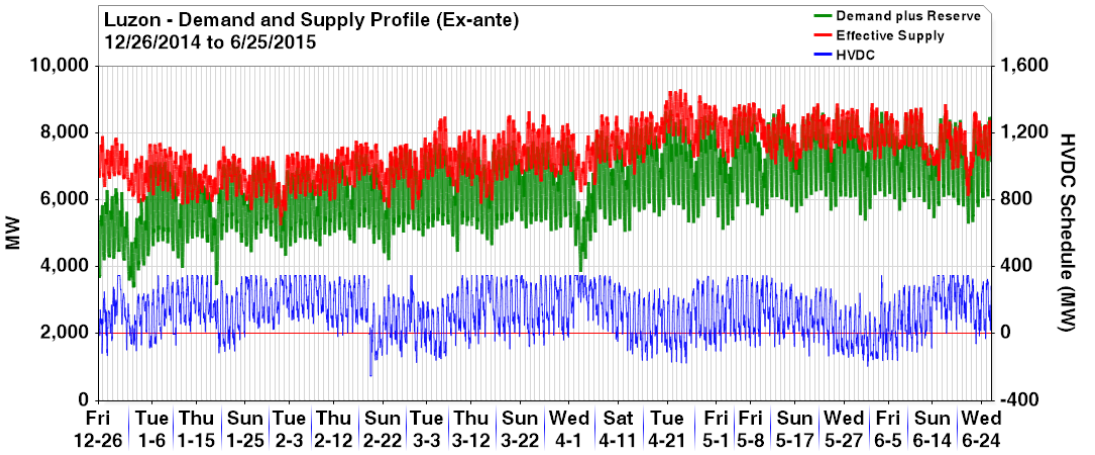

Figure 17 Demand and Effective Supply, 2015 - Luzon, 1st Half

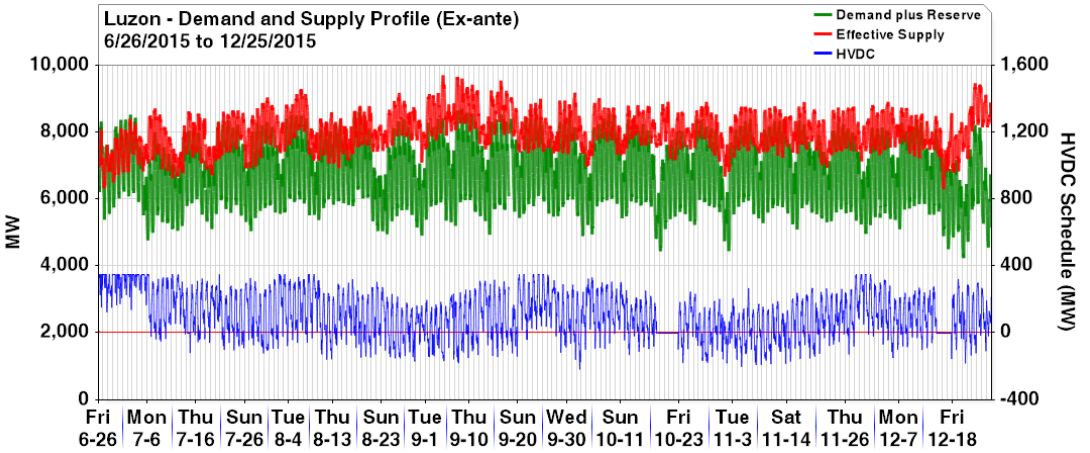

Figure 18 Demand and Effective Supply, 2015 - Luzon, 2nd Half

	Sumary of Demand and Supply (MW) - Luzon, 2015						
	Jan	Feb	Mar	Apr	May	Jun	Jul
Avg. Demand	5,495	5,996	6,356	6,582	7,160	7,223	6,797
Avg. Effective Supply	6,811	6,809	7,266	7,785	8,099	7,848	7,606
Avg. Supply Margin	1,317	814	910	1,203	939	625	810
continuation...	Aug	Sep	Oct	Nov	Dec	Annual Avg	
Avg. Demand	6,855	8,401	8,061	7,975	8,019	6,631	
Avg. Effective Supply	8,018	8,401	8,061	7,975	8,019	6,631	
Avg. Supply Margin	1,163	1,492	1,267	1,139	1,444	1,095	

Table 18 Demand and Supply Summary - Luzon, 2015

	Sumary of Demand and Supply (MW) - Luzon, 2014						
	Jan	Feb	Mar	Apr	May	Jun	Jul
Avg. Demand	5,424	5,785	6,076	6,400	6,970	6,854	6,650
Avg. Effective Supply	7,104	7,284	6,948	6,966	7,699	7,489	7,008
Avg. Supply Margin	1,680	1,499	871	567	729	635	358
continuation...	Aug	Sep	Oct	Nov	Dec	Annual Avg	
Avg. Demand	6,356	6,318	6,449	6,388	6,146	6,307	
Avg. Effective Supply	7,391	7,372	7,672	7,663	7,789	7,377	
Avg. Supply Margin	1,036	1,054	1,223	1,275	1,644	1,069	

Table 19 Demand and Supply Summary - Luzon, 2014

In the Visayas region, effective supply[14] levels dropped by 0.3 percent in year 2015 (from 1,468 MW last year to 1,463 MW), particularly during the summer months. In April, May and June, average supply were lower by 2.6 percent (from 1,518 MW to 1,479 MW), 2.4 percent (from 1,527 MW to 1,490 MW) and 6.9 percent (from 1,510 MW to 1,405 MW), respectively.

14 The regional effective supply is equal to the offered capacity of all generator resources in each region adjusted for any security limit provided by the System Operator and other constraints considered during MMS simulation such as generator offered ramp rates, excluding the HVDC import/export.

Essentially driven by the high outage capacity during the period, average supply levels plunged to its lowest during the first quarter of the year, with the January billing month registering the lowest average effective supply at 1,363 MW. Quarterly supply levels were observed to be increasing, but looking at the monthly average trend showed the fluctuating levels of effective supply in the region this year. The highest increase in supply was posted in October, demonstrated by a 10.9 percent increase at an average of 1,572 MW, from last year's average of 1,418 MW.

Supply margins were lower this year by 1.9 percent from last year's average of 296 MW to 291 MW. Though demand[15] levels were generally lower when compared to the previous year, thinning of supply margins were nevertheless observed particularly during the summer months. Decline in the respective supply margins in April, May and June were significantly higher by 17.9 percent (from last year's 390 MW to 320 MW), 7.1 percent (from 290 MW to 270 MW), 16.8 percent (from 265 MW to 221 MW), respectively. The billing months of August, September and November likewise incurred lower supply margins this year, from 297 MW to 287 MW (decline by 3.5 percent), from 329 MW to 314 MW (4.6 percent) and from 224 MW to 209 MW (6.7 percent, respectively, suggesting that supply and demand conditions this year were generally tighter, when compared to the previous year.

High demand levels were observed in the region during the last quarter of the year, averaging at 1,265 MW, 1,283 MW and 1,230 MW in October, November and December, respectively.

Maximum supply in Visayas was posted at 1,724 MW on 24 September at 1400H while minimum supply was recorded at 912 MW on 20 February at 0900H.

This year, the HVDC power flow continued to be mostly directed towards the Luzon region. Generating plants in the Visayas continued to export cheaper energy by as much as 350 MW through the HVDC Interconnection, particularly during peak hours. Increase in the frequency of the power flow from Luzon to Visayas was observed during the June and November billing months, which were the months associated with narrow supply margin levels in the region during the billing year.

Note that year-on-year comparison of the demand and supply in the Visayas region excluded the billing months of January to March 2014, following the ERC's partial market suspension which affected the Visayas during these months due to the destruction of power facilities caused by typhoon Yolanda in the region. The ERC's partial market suspension in the Visayas was lifted on 26 March 2014.

15 The regional demand is equal to the total scheduled MW of all load resources for each respective region plus losses.

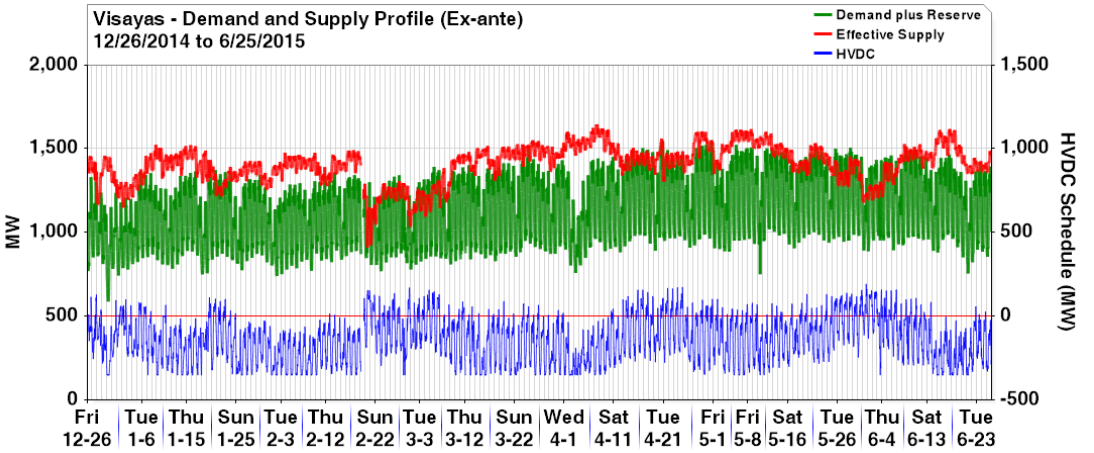

Figure 19 Demand and Effective Supply, 2015 - Visayas, 1st Half

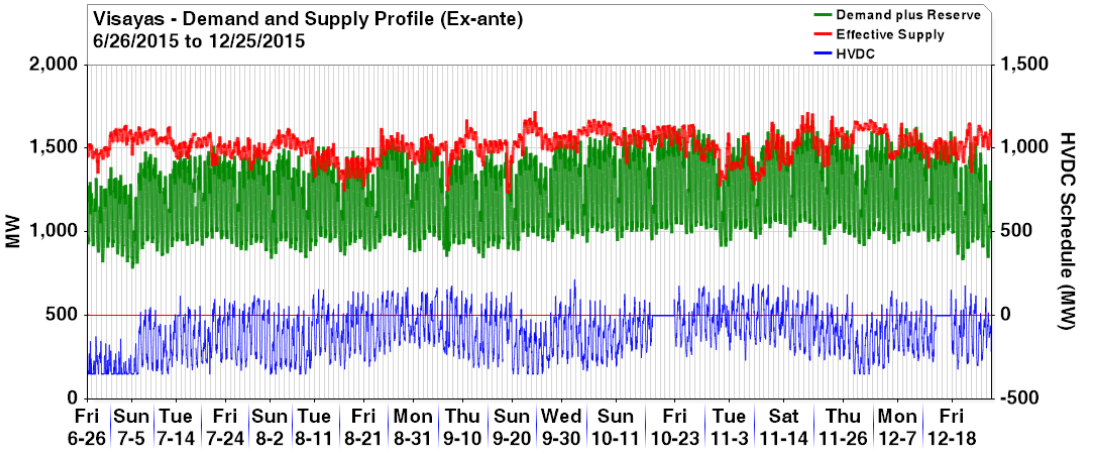

Figure 20 Demand and Effective Supply, 2015 - Visayas, 2nd Half

	Sumary of Demand and Supply (MW) - Visayas, 2015						
	Jan	Feb	Mar	Apr	May	Jun	Jul
Avg. Demand	1,033	1,057	1,106	1,159	1,220	1,184	1,155
Avg. Effective Supply	1,363	1,343	1,359	1,479	1,490	1,405	1,531
Avg. Supply Margin	330	287	254	320	270	221	375
continuation...	Aug	Sep	Oct	Nov	Dec	Annual Avg	
Avg. Demand	1,172	1,199	1,265	1,283	1,230	1,172	
Avg. Effective Supply	1,459	1,513	1,572	1,491	1,546	1,463	
Avg. Supply Margin	287	314	308	209	317	291	

Table 20 Demand and Supply Summary - Visayas, 2015

	Sumary of Demand and Supply (MW) - Visayas, 2014				
	Apr	May	Jun	Jul	Aug
Avg. Demand	1,129	1,237	1,244	1,160	1,189
Avg. Effective Supply	1,518	1,527	1,510	1,46	1,486
Avg. Supply Margin	390	290	265	302	297
continuation...	Sep	Oct	Nov	Dec	Annual Avg
Avg. Demand	1,162	1,34	1,173	1,113	1,172
Avg. Effective Supply	1,491	1,418	1,397	1,395	1,468
Avg. Supply Margin	329	284	224	282	296

Table 21 Demand and Supply Summary - Visayas, 2014

RESERVE MARGIN INDEX (RMI)

The reserve margin index measures the supply-demand balance in the market. Its purpose is to measure and identify how tight the energy balance in the market is, because a tight energy balance in the market is usually accompanied by higher spot prices and tighter supply conditions suggest greater opportunities to exercise market power.

The hourly RMI trend during the covered period shows that for the most part or 76.6 percent of the all the trading intervals in year 2015, the supply margin exceeded 10 percent of the hourly demand. This is most particularly manifested during off-peak periods (at 95.5 percent of the time during off-peak hours). It was observed that occurrences of trading intervals with RMIs of less than 10 percent was highest during the hot summer months of May and June when demand picked up. Decline in supply was likewise noted in June. During this time, occurrences of price spikes during the evening off-peak hours were observed.

Moving further, the hourly RMI had gone on increasing trend from July to September attributed to better demand and supply conditions during these months. However, increase in the occurrence of RMI of less than 10 percent was again observed starting October, as supply levels begin to decline following the high outage capacity which was recorded in the last quarter of the year.

Overall, better generation and demand balance was noted in year 2015 when compared to the previous year. The frequency of trading intervals with RMIs of less than 10 percent occurred in about 28 percent of the time in 2014, higher by 4.5 percent from the 23.4 percent posted this year. Correspondingly, trading intervals with RMIs above 10 percent was higher this year than last year's 72 percent, suggesting that generally, supply and demand conditions were tighter in the previous year.

Note that the system-wide RMI during the first quarter of 2014 covered the Luzon region only, on account of the ERC's partial market suspension affecting the Visayas region which was lifted only on 26 March 2014.

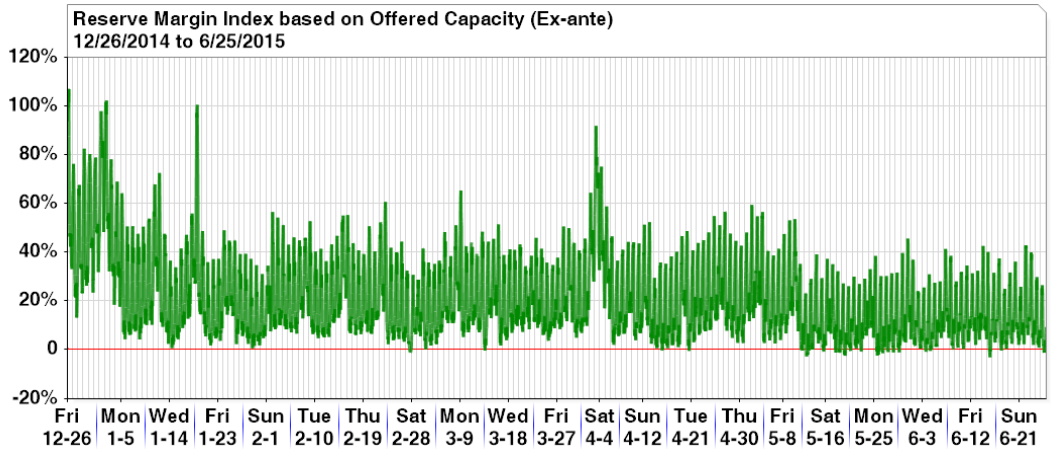

Figure 21 Reserve Margin Index (RMI), System - 1st Half

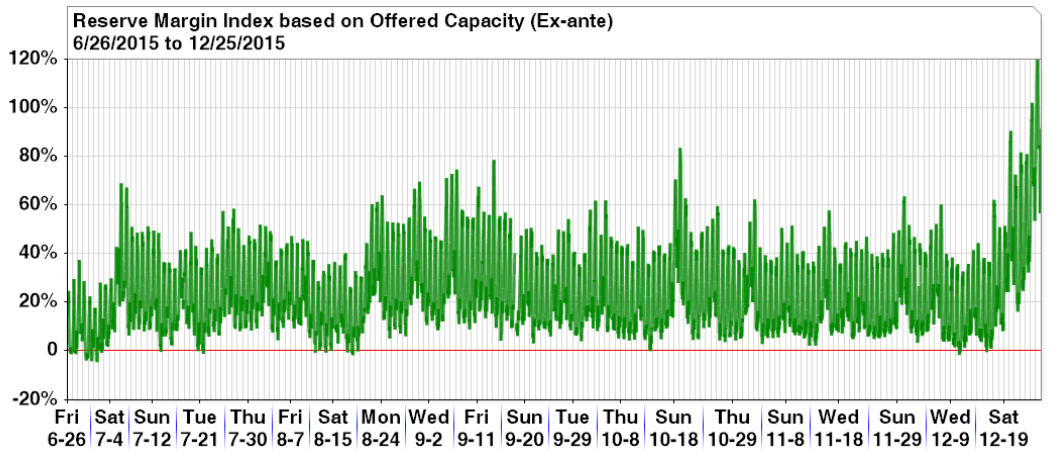

Figure 22 Reserve Margin Index (RMI), System - 2nd Half

	RMI Distribution by Billing Month (%) - 2015						
	Jan	Feb	Mar	Apr	May	Jun	Jul
Less or equal to 10%	14.4	23.6	24.4	21.9	35.3	49.3	28.4
More than 10%	85.6	76.4	75.6	78.1	64.7	50.7	71.6
continuation...	Aug	Sep	Oct	Nov	Dec	Annual Avg	
Less or equal to 10%	17.0	4.7	15.1	25.4	21.7	23.4	
More than 10%	83.0	95.3	84.9	74.6	78.3	76.6	

Table 22 RMI Distribution - System, 2015

	No. of Trading Intervals		Percent of Time	
RMI Distribution	**Peak**	**Off-Peak**	**Peak**	**Off-Peak**
Less or equal to 10%	1,825	221	48.3	4.5
More than 10%	1,954	4,737	51.7	95.5

Table 23 RMI Distribution by Hour Type - System, 2015

	RMI Distribution by Billing Month (%) - 2014						
	Jan	Feb	Mar	Apr	May	Jun	Jul
Less or equal to 10%	3.1	8.7	39.3	46.4	45.4	53.1	54.7
More than 10%	96.6	91.3	60.7	53.6	54.6	46.9	45.3
continuation...	Aug	Sep	Oct	Nov	Dec	Annual Avg	
Less or equal to 10%	29.6	18.3	166.9	14.8	6.8	28.0	
More than 10%	70.4	81.7	83.1	85.2	93.2	72.0	

Table 24 RMI Distribution - System, 2014

OUTAGES

OUTAGE CAPACITY BY PLANT TYPE

Outage capacity decreased by about 4.0 percent from last year's average of 2,103 MW to 2,019 MW this year. The same is influenced by the decline of about 10.0 percent in the outage capacity of geothermal plants which averaged at 388 MW in 2014 to 349 MW in the current year. It can be recalled that geothermal plants came from a significantly high outage incidence in the previous year, mainly on account of the destruction of power facilities in the Visayas affecting the January to March 2014 billing months. More geothermal capacities were likewise made available this year, an example of which is Bacman 2 which was mostly on outage in the previous year. Similarly, oil-based plants likewise registered a 22.8 percent decrease in its outage capacity, averaging at 332 MW from last year's 431 MW.

Despite said decrease, coal, natural gas and hydro plants posted year-on-year increases in their outage capacities at 3.8 percent, 1.4 percent and 8.3 percent, respectively.

Coal plants posted significant increase in its outage capacity during the first and fourth quarters of the year. This drove the increase in the 2015 outage capacity of coal plants from an average of 862 MW in the previous year to 894 MW this year. Natural gas plants likewise posted higher outage capacity this year particularly during the January to April billing months, as well as in June and July partly driven by the month-long planned outage of Ilijan A in the July billing month. Outage capacity of natural gas plants slightly increased by 1.4 percent from 220 MW in 2014 to 223 MW this year. Meanwhile, hydro plants also increased its outage capacity by 8.3 percent, from an average of 203 MW in the previous year to 220 MW.

It is observed that unavailable coal generating units resumed operations in time for the seasonal higher outage capacity among hydro plants during the second quarter (summer months). Consequently, driven by the high outage capacity among coal plants, outage capacity was at its highest during the first quarter, averaging at 2,722 MW, 2,976 MW and 2,383 MW from January to March.

As already mentioned, lower outage capacity levels during the summer months of April and May was observed this year attributed to the considerable decrease by about 81.8 percent in the outage capacity of coal plants from an average of 1,119 MW in March to 204 MW in April, and 240 MW in May. Nevertheless, outage capacity remained high in the June and July billing months, averaging at 1,969 MW and 2,079 MW, respectively, when all resource types posted a relatively higher level of outage capacity. Note that the lowest average monthly supply margin level was observed in June. Outage capacity level dropped in the third quarter and recorded

the lowest monthly average outage capacity during the September billing month at 1,441 MW. Outage capacity of coal plants again increased during the last quarter, averaging at 1,237 MW, in part influencing the high outage capacity from October to December, averaging at 1,771 MW, 2,238 MW and 2,220 MW, respectively.

The maximum outage capacity posted at 4,044 MW was recorded from 27 February at 2300H to 28 February at 0100H when one unit of Limay B went on forced outage which overlapped with the existing outages of major Luzon coal plants Calaca 1 and 2, GN Power 1 and 2, Masinloc 1, SL Thermal Energy, QPPL, and Sual 1.

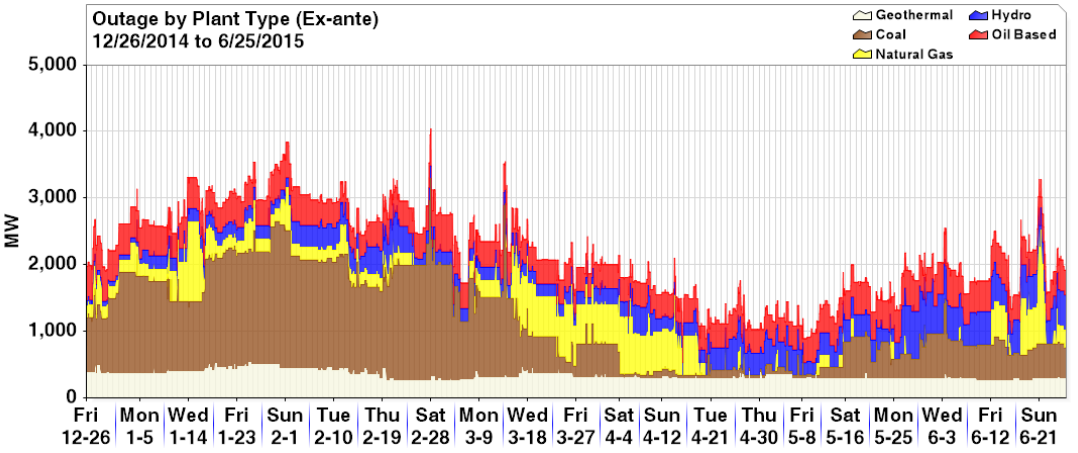

Figure 23 Capacity on Outage by Plant Type - 1st Half

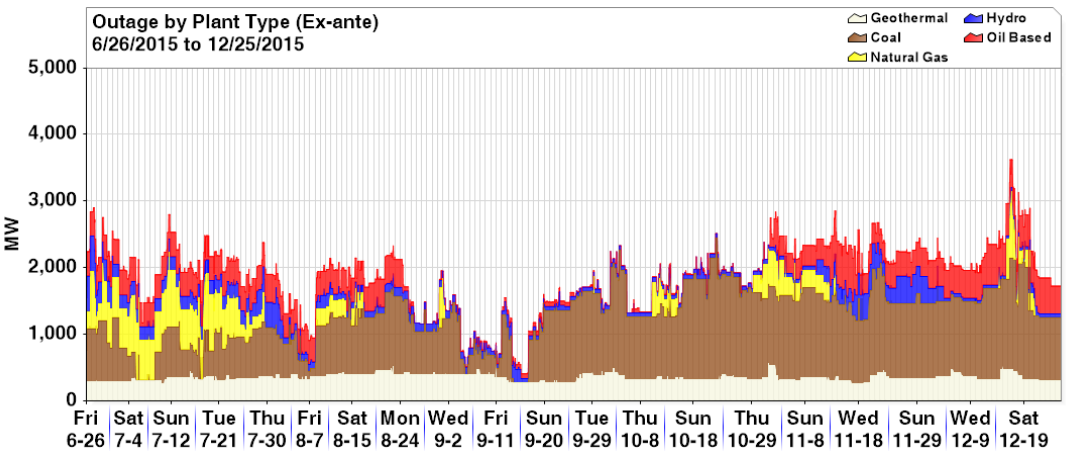

Figure 24 Capacity on Outage by Plant Type - 2nd Half

Average Outage Capacity by Billing Month (MW) - 2015							
Plant Type	Jan	Feb	Mar	Apr	May	Jun	Jul
Coal	1,346	1,661	1,119	204	240	518	535
Nat Gas	370	214	336	492	42	212	618
Geo	413	400	325	310	312	286	328
Hydro	155	305	190	261	322	509	235
Oil	438	397	413	366	410	444	363
Total	2,722	2,976	2,383	1,632	1,327	1,969	2,079
continuation...	Aug	Sep	Oct	Nov	Dec	Annual Avg	
Coal	768	640	1,271	1,241	1,199	894	
Nat Gas	94	18	56	160	69	223	
Geo	391	349	362	349	362	349	
Hydro	166	104	72	180	131	220	
Oil	359	30	9	308	458	332	
Total	1,779	1,141	1,771	2,238	2,220	2,019	

Table 25 Capacity on Outage by Plant Type, 2015

	Year-onYear Average Outage Capacity Comparision by Billing Month						
	Jan	Feb	Mar	Apr	May	Jun	Jul
2015 (MW)	2,722	2,976	2,383	1,632	1,327	1,969	2,079
2014 (MW)	2,098	2,126	2,320	2,650	1,944	1,942	2,894
Y-Y (%) Change	29.8	40.0	2.7	(38.4)	(31.7)	1.4	(28.2)
continuation...	Aug	Sep	Oct	Nov	Dec	Annual Avg	
2015 (MW)	1,779	1,141	1,771	2,238	2,220	2,019	
2014 (MW)	2,001	2,133	1,929	1,676	1,544	2,103	
Y-Y (%) Change	(11.1)	(46.5)	(8.2)	33.5	43.8	(4.0)	

Table 26 Year-on-Year Average Outage Capacity Comparison

In terms of the frequency of outage incidents over the year, oil-based plants recorded the highest number of outage occurrences with a total of 249 incidents, closely followed by geothermal plants with 235, coal plants with 195, hydro plants with 171 and natural gas plants with 109 outage incidents. Monthly comparison of the frequency of outages in 2015 showed that the June and October billing months posted the highest frequency of outage occurrences at 102 and 106 incidents, respectively. Note that the monthly frequency of outages mentioned in this chapter is a count of the actual occurrence of the outage, regardless of length. Thus, a short-duration outage and an outage spanning an entire year are given one count each. Overall, occurrences of outage incidents totalled 959 during billing year 2015.

Monthly Frequency of Outage Incidents, 2015													
Plant Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Grand Total
Coal	23	15	18	9	11	11	21	18	27	16	16	10	185
Geo	32	22	26	12	20	8	26	18	17	21	19	14	235
Hydro	6	14	4	15	11	17	1	25	9	48	15	6	171
NatG	12	5	9	16	6	21	11	4	3	4	6	12	109
Oil	18	14	21	19	33	45	14	7	14	17	26	21	249
Grand Total	91	70	78	71	81	102	73	72	70	106	82	63	959

Table 27 Monthly Frequency of Outage Incidents, 2015

Geothermal plants recorded the highest total outage factor[16] system-wide, averaging at 19.8 percent in 2015. It is observed that geothermal plants consistently posted its outage factor at above 16.2 percent, across all billing months. The total outage factor of coal plants were the next highest, averaging at 15.5 percent during the billing year. Following its outage capacity data, the outage factor of coal plants were highest during the 1st and 4th quarters of the year, indicating that coal plants incurred high outage levels during these periods.

Oil-based plants likewise recorded high outage factor which averaged at 14.1 percent this year. Its outage factor reached a high of 19.0 percent, 18.7 percent and 19.3 percent, respectively, during the January, June and December billing months, consistent with the high outage capacities of oil-based plants during these months. On the other hand, hydro plants incurred an 8.9 percent total outage factor, mainly contributed by its high unplanned outage factor at 7.3 percent. The total outage factor of hydro plants was highest in June at 20.9 percent attributable to its high unplanned outages during this month. Natural gas plants obtained an outage factor of 7.9 percent, with unplanned outage accounting for 5.7 percent of its total outage factor. Outage factor of natural gas plants was particularly high in July at 22.3 percent, attributable to the outages related to the Malampaya gas supply restriction during this period.

Outage Factor (%) by Billing Month - System-2015														
Plant Type	Outage Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Grand Total
COAL	Planned Outage	12.2	15.1	5.3	0.7	0.0	5.9	3.9	2.1	3.2	10.9	10.9	7.8	6.5
	Unplanned Outage	12.3	13.7	14.3	3.0	4.2	3.1	5.5	11.3	7.8	10.5	10.0	12.4	9.0
	Deactivated Shutdown	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal Total Outage Factor		24.6	28.8	19.6	3.7	4.2	9.1	9.4	13.4	11.0	21.4	20.9	20.2	15.5

16 Outage factor is the ratio of the product of the capacity on outage and total number of outage days of plant type to the product of total capacity and period days covered, expressed in percent.

Based on the Daily Operations Report by NGCP-SO, which adopted the revised outage classification of ERC through its Resolution No. 17, s.2013 “Adopting and Approving the Rules and Procedures to Govern the Monitoring of Reliability Performance of Generating Units and Transmission System”.

Unplanned Outage is comprised of forced outage and maintenance outage.

Outage Factor (%) by Billing Month - System-2015														
Plant Type	Outage Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Grand Total
NATG	Planned Outage	2.0	0.1	2.0	0.7	0.3	-	18.9	0.9	0.0	1.5	-	0.0	2.1
	Unplanned Outage	11.4	7.7	10.1	17.1	1.2	7.6	3.4	2.5	-	0.4	5.6	2.5	5.7
	Deactivated Shutdown	-	-	-	-	-	-	-	-	0.6	0.0	-	-	0.1
NAT GAS Total Outage Factor		13.4	7.9	12.1	17.8	1.4	7.6	22.3	3.3	0.6	1.9	5.6	2.5	7.9
GEO	Planned Outage	3.1	2.6	0.0	0.0	0.0	-	0.3	1.5	1.0	0.5	1.3	0.9	1.0
	Unplanned Outage	11.3	11.8	11.7	11.9	12.1	10.6	10.9	15.1	13.2	14.4	12.8	13.7	12.5
	Deactivated Shutdown	9.2	8.3	6.8	5.6	5.6	5.6	7.3	5.6	5.6	5.6	5.6	5.8	6.4
GEO Total Outage Factor		23.6	22.7	18.5	17.5	17.7	16.2	18.6	22.1	19.7	20.5	19.6	20.4	19.8
HYD	Planned Outage	0.4	-	3.8	3.5	5.0	1.3	0.1	-	-	-	0.3	2.6	1.4
	Unplanned Outage	5.1	11.7	4.0	7.0	8.0	19.6	9.4	6.8	4.2	3.0	5.7	2.7	7.3
	Deactivated Shutdown	0.9	0.9	-	0.3	0.2	-	-	0.0	0.1	0.1	-	-	0.2
HYDRO Total Outage Factor		6.4	12.6	7.8	10.8	13.2	20.9	9.5	6.8	4.3	3.1	5.9	5.3	8.9
OIL	Planned Outage	0.0	0.0	0.0	0.0	0.0	-	0.0	-	-	-	2.3	-	0.2
	Unplanned Outage	19.0	17.3	17.9	15.4	17.2	18.7	15.6	15.1	1.3	0.4	10.3	19.2	13.9
	Deactivated Shutdown	-	-	-	-	-	0.1	-	-	-	-	0.5	0.1	0.1
OIL Total Outage Factor		19.0	17.3	17.9	15.4	17.3	18.7	15.6	15.1	1.3	0.4	13.0	19.3	14.1

Table 28 Outage Factor

Outage capacity likewise declined in the Luzon region by about 3.2 percent, from 1,925 MW in the previous year to 1,863 MW. High outage capacity were observed most particularly during the first quarter of the billing year, with outage capacity averaging at 2,466 MW, 2,709 MW and 2,159 MW from January to March. This was reduced in the second and third quarters, though surges in outage capacity were still noted during some periods. The lowest monthly outage capacity was noted in September, averaging at 1,041 MW which resulted in the highest monthly effective supply level in the region in 2015.

Major coal plants contributed about 50 percent of the total outage capacity during the first quarter of the year. GN Power 1, which went on forced outage since 26 October 2014 went back online only on 17 March while GN Power 2 which underwent maintenance outage since 29 December 2014, resumed operations only on 23 March. On the other hand, major coal plant Masinloc 1 was on planned outage from 01 January to 02 February; Calaca 1, on 26 December to 10 January; QPPL, from 17 January to 05 March; and SLTEC 1, from 16 January to 05 April.

On the other hand, the highest increase in average outage capacity was posted by natural gas plants in June at 410.4 percent (from 42 MW in May to 212 MW), which further increased in July by 191.1 percent (618 MW). In June, outages of natural gas plants were mainly because of the

forced outage of Ilijan units on 15 June and from 17 to 22 June due to limited Malampaya gas supply. Moreover, San Lorenzo and Sta. Rita units went on a series of short outages during the month. Meanwhile, series of outages following the Malampaya gas restriction, coupled with the month long planned outage of Ilijan A (Units 2 and 3) were observed in July.

Hydro plants, on the other hand, recorded its highest outage capacities during the second quarter, coinciding with the summer season. Rise in its outage capacities were observed in April, May and June, averaging at 261 MW, 322 MW and 509 MW, respectively. February likewise posted high outage capacity for hydro plants at an average of 305 MW following the maintenance outages of Kalayaan 1, 2 and 4. In June, increase in the outage capacity of hydro plants was due to the simultaneous maintenance outages of major hydro plants such as Angat, Magat, Kalayaan, Pantabangan and San Roque.

The Luzon region likewise observed a considerably higher average outage capacity during the last quarter of the year, posted at 1,695 MW, 2,075 MW and 2,124 MW, respectively, in October, November and December. Coal plants, which accounted for about 61 percent of the total outage capacity, drove the surge in the outage capacity level during these months. Significantly, the 647 MW of Sual 2 remained unavailable during the period, due to the plant's conduct of annual preventive maintenance since 16 September until 17 December. Further, Calaca 2 underwent maintenance outage while Masinloc 1 was on forced outage resulting in the increase in average outage capacity of coal plants to 1,171 MW in December from previous month's 1,138 MW.

Geothermal plants consistently posted its monthly outage capacity within the range of 250 MW to 355 MW, with the January billing month posting the highest monthly average at 355 MW. Rise in geothermal plants' outage was noted this month on account of the maintenance outage of Bacman 1 beginning 28 December 2014 which persisted until the end of the month. Year/s-long outages of geothermal plants Makban 6 (from 13 November 2014), Tiwi 2 (from 18 December 2014 and Tiwi 3 (from 23 October 2005) were also noted.

Oil-based plants' outage capacity averaged at 328 MW during the year, with December marking the highest outage level among oil-based plants at an average of 457 MW. Outage capacity of oil-based plants were also noted to be higher during the first quarter of the year. Limay 1 and 2 went on maintenance outage while Limay 3, 4, 5 and 8 recorded forced outages in said months on top of the forced outage of the 300 MW unit of Malaya 1 which started on 21 March 2014 due to high turbine vibration. Outage capacities of oil-based plants were also relatively high in the second semester. Limay 3 and 6 as well as Navotas all registered forced outages during these months on top of the existing outage of Malaya 1. Limay 2 also contributed, with its maintenance outage which lasted from 16 February until 24 August.

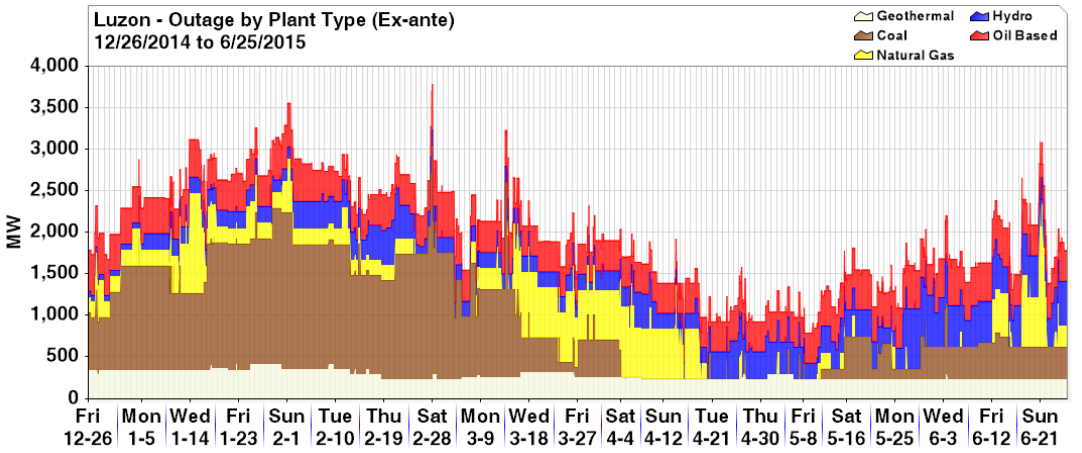

Figure 25 Capacity on Outage by Plant Type (Luzon) - 1st Half

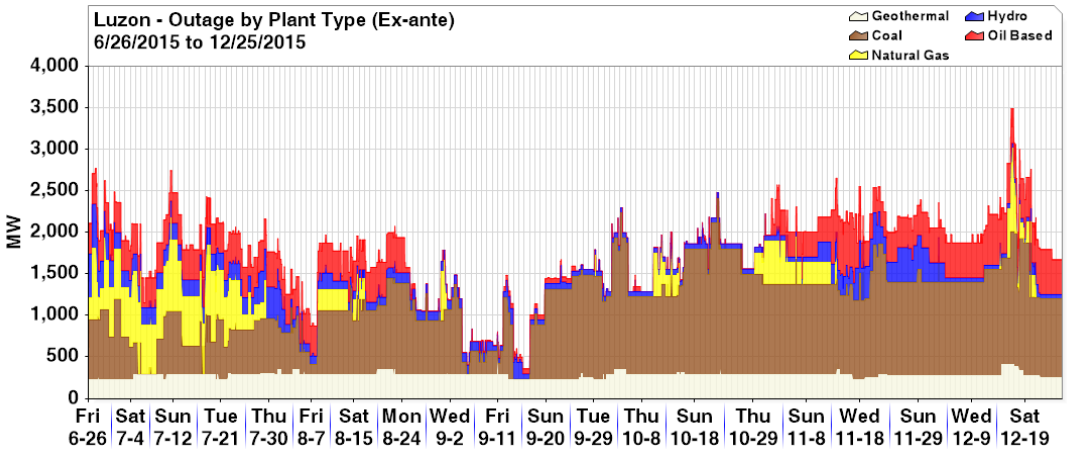

Figure 26 Capacity on Outage by Plant Type (Luzon) - 2nd Half

Average Outage Capacity by Billing Month (MW) - Luzon, 2015							
Plant Type	Jan	Feb	Mar	Apr	May	Jun	Jul
Coal	1,166	1,472	952	136	160	379	502
Nat Gas	370	214	336	492	92	212	618
Geo	355	332	277	250	253	241	279
Hydro	155	305	190	261	322	509	235
Oil	420	386	405	365	407	441	362
Total	2,466	2,709	2,159	1,503	1,184	1,783	1,995
continuation...	Aug	Sep	Oct	Nov	Dec	Annual Avg	
Coal	711	618	1,267	1,138	1,171	805	
Nat Gas	95	18	56	160	69	223	
Geo	308	273	296	291	294	288	
Hydro	166	104	72	180	131	220	
Oil	359	28	3	306	457	328	
Total	1,639	1,041	1,695	2,075	2,124	1,863	

Table 29 Capacity on Outage by Plant Type - Luzon

Year-onYear Average Outage Capacity Comparision by Billing Month - Luzon							
	Jan	Feb	Mar	Apr	May	Jun	Jul
2015 (MW)	2,466	2,709	2,159	1,503	1,184	1,783	1,995
2014 (MW)	1,756	1,823	2,162	2,532	1,803	1,759	2,6725
Y-Y (%) Change	40.4	48.6	(0.1)	(40.6)	(34.4)	1.4	(25.4)
continuation...	Aug	Sep	Oct	Nov	Dec	Annual Avg	
2015 (MW)	1,639	1,041	1,695	2,075	2,124	1,863	
2014 (MW)	1,867	2,037	1,804	1,526	1,379	1,925	
Y-Y (%) Change	(12.2)	(48.9)	(6.0)	36.0	54.0	(3.2)	

Table 30 Year-on-Year Average Outage Capacity Comparison - Luzon

Mirroring the trend system-wide, the June and October billing months likewise posted the highest number of outage incidents in 2015, indicating that outage incidents mostly occurred during these months. Hydro and coal plants contributed the bulk in the count of outage incidents, registering the highest occurrences at 171 and 130 incidents, respectively. Hydro plants registered a significant number of short-duration outages in October. On the other hand, it can be recalled that simultaneous outages of large coal plants were observed in numerous intervals during the October billing month due to various technical concerns. Further, it is noted that outage incidents among natural gas plants was highest in June, attributed to outages related to the Malampaya gas supply restriction during the month.

Monthly Frequency of Outages by Plant Type, Luzon - 2015													
Plant Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Grand Total
Coal	15	4	14	5	8	6	18	13	18	12	9	8	130
Geo	13	8	6	-	8	1	10	7	7	9	7	5	81
Hydro	6	14	4	15	11	17	1	25	9	48	15	6	171
NatG	12	5	9	16	6	21	11	4	3	4	6	12	109
Oil	9	9	8	5	15	17	8	6	3	2	18	18	118
Grand Total	55	40	41	41	48	62	48	55	40	75	55	49	609

Table 31 Monthly Frequency of Outage Incidents, Luzon - 2015

Consistent with the high outage capacities of the Luzon coal plants during the first and last quarters of the year, its corresponding planned and unplanned outage factors likewise demonstrated significant increases during the period. These drove the total outage factor of the Luzon coal plants to 16.0 percent in 2015.

Natural gas plants, on the other hand, registered its outage factor at 7.9 percent, while hydro plants recorded its outage factor at 8.9 percent and oil-based plants, at 17.2 percent. Outage factor of geothermal plants remained consistently high throughout the year, all posting an outage factor of above 27 percent. For year 2015, total outage factor of geothermal plants was posted at 32.4 percent. It is observed that 12.7 percent of the total outage factor of geothermal plants is on account of deactivated shutdown.

Outage Factor (%) by Billing Month - Luzon-2015														
Plant Type	Outage Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Grand Total
COAL	Planned Outage	12.5	16.4	4.9	0.8	0.0	6.7	4.4	2.3	3.7	12.5	12.5	9.0	7.2
	Unplanned Outage	12.3	13.3	14.3	2.0	3.2	0.8	5.6	11.7	8.3	12.0	9.6	13.7	8.9
	Deactivated Shutdown	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal Total Outage Factor		24.8	29.7	19.3	2.9	3.2	7.6	10.0	14.0	12.0	24.5	22.1	22.6	16.0
NATG	Planned Outage	2.0	0.1	2.0	0.7	0.3	0.0	18.9	0.9	0.0	1.5	0.0	0.0	2.1
	Unplanned Outage	11.4	7.7	10.1	17.1	1.2	7.6	3.4	2.5	0.0	0.4	5.6	2.5	5.7
	Deactivated Shutdown	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.0	0.0	0.0	0.1
NAT GAS Total Outage Factor		13.4	7.9	12.1	17.8	1.4	7.6	22.3	3.3	0.6	1.9	5.6	2.5	7.9
GEO	Planned Outage	5.8	3.6	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.1	0.0	0.0	0.8
	Unplanned Outage	16.1	17.5	17.9	16.9	17.4	16.0	16.9	23.4	19.6	22.2	21.7	21.5	18.9
	Deactivated Shutdown	18.3	16.5	13.5	11.2	11.1	11.1	14.6	11.1	11.1	11.1	11.1	11.6	12.7
GEO Total Outage Factor		40.2	37.6	31.3	28.1	28.5	27.1	31.5	34.6	30.7	33.4	32.8	33.1	32.4
HYD	Planned Outage	0.4	-	3.8	3.5	5.0	1.3	0.1	0.0	0.0	0.0	0.3	2.6	1.4
	Unplanned Outage	5.1	11.7	4.0	7.0	8.0	19.3	9.4	6.8	4.2	3.0	5.7	2.7	7.3
	Deactivated Shutdown	0.9	0.9	-	0.3	0.2	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.2
HYDRO Total Outage Factor		6.4	12.6	7.8	10.8	13.2	20.9	6.5	6.8	4.3	3.1	5.9	5.3	8.9
OIL	Planned Outage	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	2.5	0.0	0.2
	Unplanned Outage	22.6	20.9	21.9	19.0	21.1	22.9	19.1	18.6	1.4	0.2	12.6	23.6	16.9
	Deactivated Shutdown	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.6	0.2	0.1
OIL Total Outage Factor		22.6	20.9	21.9	19.0	21.1	23.0	19.1	18.6	1.4	0.2	15.9	23.7	17.2

Table 32 Outage Factor - Luzon

In the Visayas region, outage capacity recorded a decrease by 12.8 percent from an average of 178 MW in 2014 to 155 this year. Coal plants accounted for majority or 57.4 percent (averaged at 89 MW) of the total outage capacity in the region, followed by geothermal plants with 39.6 percent (62 MW) while the remaining 2.9 percent (5 MW) is attributed to oil-based plants.

Outage capacity in the Visayas was highest during the first quarter of the year, averaging at 256 MW in January, 267 MW in February and 223 MW in March. It is noted that coal plants CEDC 1 and PEDC 1 underwent planned outages for their preventive maintenance shutdown in January. Also, geothermal plant LGPP underwent forced outage due to the tripping of 138kV Ormoc-Tongonan line at this month. In February, coal plants KSPC 1 & 2 and PEDC 1 went on planned and forced outages which drove the increase in the average outage capacity of

Visayas coal plants from 180 MW to 189 MW. Similarly, the planned outage of Palinpinon 1 from 23 January to 7 February drove the average outage capacity of Visayas geothermal plants up to 68 MW from 58 MW. Meanwhile, among oil-based plants, only Panay DPP went on outage during the February billing month.

Decline in the outage capacity of the Visayas generating plants was noted during the March billing month, attributable to the resumption of operations of TPC Sangi and KSPC 2 from their forced outages and decline in the outage capacity of PEDC 1 coming from planned outage in February. Meanwhile, the decrease in the outage capacity of geothermal plants was attributable to the end of the forced outage of Leyte A in February and planned outage of Palinpinon 1.

Further decline in the outage capacity in the region was observed in the next succeeding months, except for June which likewise posted a relatively higher outage level at an average of 186 MW. Said increase in outage capacity in June was attributed to the forced outages of coal plants KEPCO Salcon 1, CEDC 1 and 2, TPC Sangi, and PEDC 2. In addition, geothermal plants PGPP1 Unit 2 and PGPP2 Units 2, 3 and 4 were also on maintenance outage during the month.

The lowest monthly outage capacity was posted in October averaging at 76 MW. Meanwhile, the minimum outage capacity was posted at an average of only 20 MW on 14 June at 1600H. On the other hand, the maximum outage capacity in the region was reached on 09 February at 0300H, posted at 607 MW.

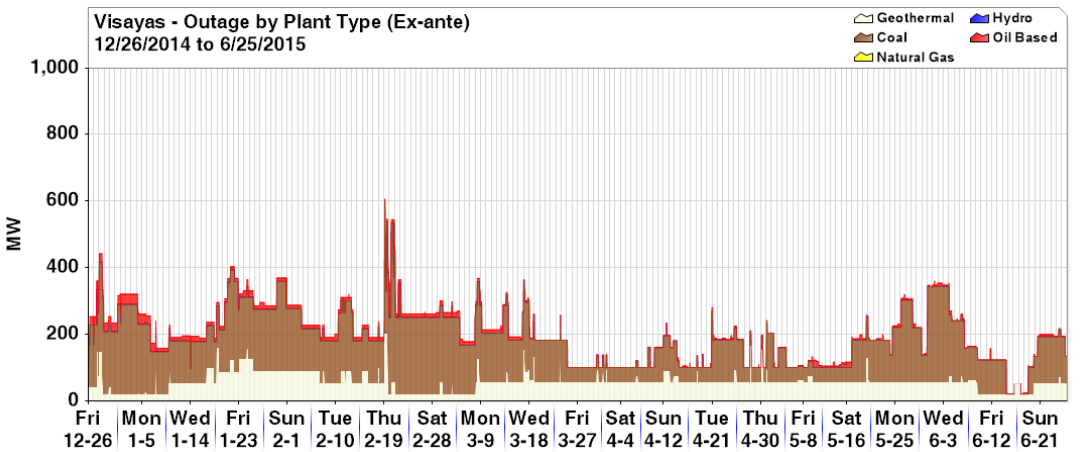

Figure 27 Capacity on Outage by Plant Type (Visayas) - 1st Half

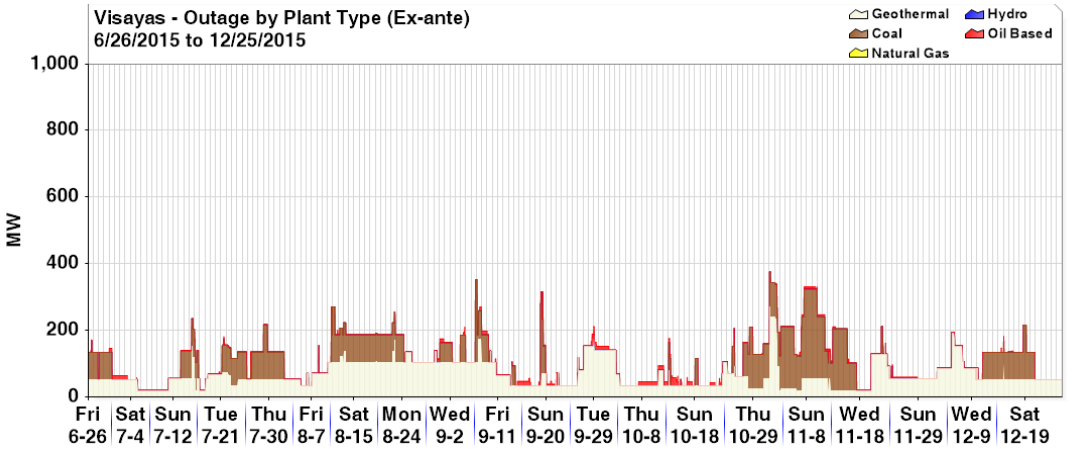

Figure 28 Capacity on Outage by Plant Type (Visayas) - 2nd Half

Average Outage Capacity by Billing Month (MW) - Visayas, 2015													
Plant Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Avg.
Coal	180	189	168	68	8	139	33	57	22	4	104	28	89
Geo	58	68	48	60	59	45	49	83	76	66	58	67	62
Oil	18	11	7	1	4	2	1	0	3	6	2	1	5
Total	256	267	223	129	143	186	84	140	100	76	163	96	155

Table 33 Capacity on Outage by Plant Type - Visayas

Year-on-Year Average Outage Capacity Comparison by Billing Month - Visayas													
Plant Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Avg.
2015 (MW)	256	267	223	129	143	186	82	140	100	76	163	96	155
2014 (MW)	342	303	158	118	141	183	220	134	96	125	150	165	178
Y-Y (%) Change	(25.1)	(11.9)	41.0	9.1	1.6	1.8	(61.9)	4.7	4.5	(39.0)	8.3	(41.6)	(12.8)

Table 34 Year-on-Year Average Outage Capacity Comparison - Visayas

In the Visayas, outage incidents most frequently occur during the June billing month, with 40 incidents. The same is driven by the significant increase in the frequency of short-duration outages among oil-based plants in June.

Over-all, the Visayas region posted a total of 350 incidents, with geothermal plants accounting for 154 outage incidents while 131 incidents were attributable to oil-based plants. The remaining 65 incidents were outages recorded by coal plants in the region.

Monthly Frequency of Outages by Plant Type - Visayas, 2015													
Plant Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Grand Total
Coal	8	11	4	4	3	5	3	5	9	4	7	2	65
Geo	19	14	20	12	12	7	16	11	10	12	12	9	154
Oil	9	5	13	14	18	28	6	1	11	15	8	3	131
Grand Total	36	30	37	30	33	40	25	17	30	31	27	14	350

Table 35 Monthly Frequency of Outage Incidents, Visayas - 2015

Outage factor in the Visayas totalled at 7.5 percent, 6.3 percent of which is attributed to the unplanned outages in the region while 1.2 percent is due to planned outage.

Coal plants in the region posted the highest outage factor at 12 percent, essentially due to unplanned outages which comprised 9.8 percent of the total outage factor among coal plants. Rise in the outage factor of coal plants were observed during the first quarter and in June, consistent with the high outage capacities exhibited during these months.

Geothermal plants posted an outage factor of 7 percent, 5.9 percent of which is on account of unplanned outages. On the other hand, oil-based plants posted an outage factor of 1.0 percent during the billing year.

Outage Factor (%) by Billing Month - Visayas-2015														
Plant Type	Outage Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Grand Total
COAL	Planned Outage	10.7	6.9	7.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.2
	Unplanned Outage	12.6	16.1	14.0	8.9	10.5	20.4	5.0	8.5	3.8	0.6	13.1	3.7	9.8
	Deactivated Shutdown	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal Total Outage Factor		23.3	23.0	21.6	8.9	10.5	20.4	5.0	8.5	3.8	0.6	13.1	3.7	12.0
GEO	Planned Outage	0.4	1.6	0.0	0.0	0.0	0.0	0.7	2.7	2.0	1.0	2.6	1.9	1.1
	Unplanned Outage	6.5	6.1	5.5	6.9	6.8	5.1	4.9	6.7	6.6	6.6	3.8	5.7	5.9
	Deactivated Shutdown	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GEO Total Outage Factor		6.9	7.8	5.5	6.9	6.8	5.1	5.6	9.5	8.6	7.5	6.4	7.6	7.0
OIL	Planned Outage	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Unplanned Outage	4.0	2.4	1.7	0.2	0.8	0.6	0.4	0.0	0.6	1.3	0.4	0.1	1.0
	Deactivated Shutdown	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OIL Total Outage Factor		4.1	2.4	1.7	0.2	0.8	0.6	0.4	0.0	0.6	1.3	0.4	0.1	1.0

Table 36 Outage Factor - Visayas

OUTAGE CAPACITY BY OUTAGE TYPE[17]

Unplanned outages account for majority or 69.6 percent of the total outage capacity in 2015, followed by planned outages which account for 24.3 percent. The remaining 6.1 percent is attributed to the occurrences of outages due to deactivated shutdown.

As already discussed, outage capacity was highest during the first quarter of the year, attributed to the high level of unplanned outages during the period. On a similar note, the level of planned outages and deactivated shutdown were also at its highest during the first quarter of 2015.

It is noted that the highest level of outage capacity all throughout the year was posted during the February billing month. This is mainly on account of the high unplanned outage during the month, averaging at 1,862 MW while planned outage capacity was likewise at its highest, posted at an average of 925 MW. The level of deactivated shutdown was similarly high during the February billing month at 168 MW.

Conversely, outage capacity was lowest during the September billing. Unplanned outage capacity was at its lowest during the month, averaging at 853 MW, while planned outage capacity was also relatively lower, posted at an average of 276 MW.

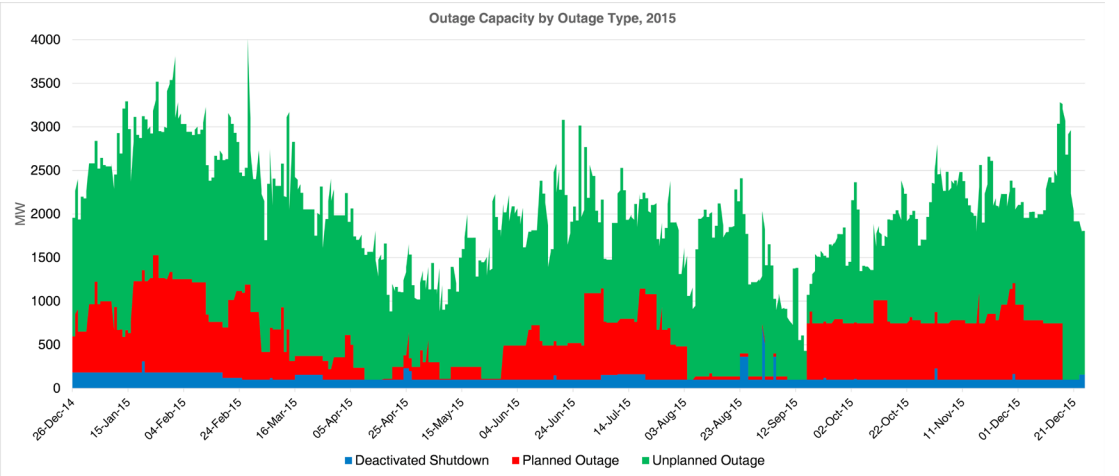

Figure 29 Capacity on Outage by Outage Type, 2015

	Average Outage Capacity by Outage Type per Billing Month (MW), 2015											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Planned Outage	792	925	453	184	142	382	757	184	276	701	680	760
Unplanned Outage	1,728	1,862	1,766	1,371	1,066	1,538	1,202	1,522	853	1,002	1,424	1,602
Deactivated Shutdown	183	168	120	107	104	100	130	120	131	102	109	107

Table 37 Capacity on Outage by Outage Type, 2015

17 Based on the Daily Operations Report by NGCP-SO, which adopted the revised outage classification of ERC through its Resolution No. 17, s.2013 “Adopting and Approving the Rules and Procedures to Govern the Monitoring of Reliability Performance of Generating Units and Transmission System”.

Consistent with the above discussion on outage capacity, unplanned outages comprised the bulk of the total outage factor system-wide, posted at 8.7 percent, while about 3.3 percent was due to planned outage factor. The remaining 0.7 percent is on account of deactivated shutdown.

Unplanned outage factor was particularly high in February at 12.6 percent. Similarly, the monthly planned outage factor and the monthly outage factor for deactivated shutdown were also highest in February at 6.1 percent and 1.1 percent, respectively.

	Outage Factor by Outage Type, 2015												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Deactivated Shutdown	0.0	1.1	0.8	0.7	0.7	0.7	0.9	0.8	0.9	0.7	0.7	0.7	0.7
Planned Outage	5.4	6.1	3.0	1.0	0.9	2.5	5.0	1.1	1.4	4.5	4.7	3.5	3.3
Unplanned Outage	3.9	12.6	12.1	9.2	7.2	10.0	8.0	10.0	5.6	6.5	9.0	10.3	8.7

Table 38 Outage Factor by Outage Type, 2015

CAPACITY GAP[18]

Generator-trading participants continued to submit capacity offers less than their respective maximum available capacity, as indicated by the persistently high level of capacity gap throughout the billing year 2015.

Capacity gap levels manifested a 5.2 percent increase this year from an average of 2,228 MW in 2014 to 2,344 MW. The April and May billing months posted the highest monthly average capacity gap at 2,766 MW and 2,860 MW, respectively, while the billing months of October and November marked the lowest monthly capacity gap levels at an average of 2,038 MW and 2,069 MW, respectively. Consequently, average capacity gap levels were observed to be generally higher during the first semester than the second semester of the year.

Among all resource types, hydro plants continued to account for majority or 40.4 percent of the system-wide capacity gap, averaging at 948 MW, followed by coal plants, accounting for 26.5 percent at an average of 622 MW; oil-based plants, which contributed 17 percent or an average of 398 MW; geothermal plants, which comprised 11 percent or 257 MW and natural gas plants, accounting for 5.1 percent at an average of 119 MW. It is noted however, that the capacity gap of hydro plants was lower by 14.4 percent this year when compared to last year's average of 1,108 MW.

When compared to the previous year, it is observed that the rise in capacity gap this year is attributable to the increase in the capacity gap among coal plants by 64.2 percent from last year's average of 379 MW. Significant increase of about 146.3 percent in the capacity gap of natural gas plants which in 2014 only averaged at 49 MW is also noted.

Note that the system-wide capacity gap levels during billing year 2014 accounted the capacity gap in the Luzon region only, in view of the market suspension in the Visayas during the 1st quarter of the previous year.

18 Capacity gap is calculated as the registered capacity less offered capacity and outage capacity, calculated for each generator resource node per trading interval, including capacity of generating units on commissioning tests.

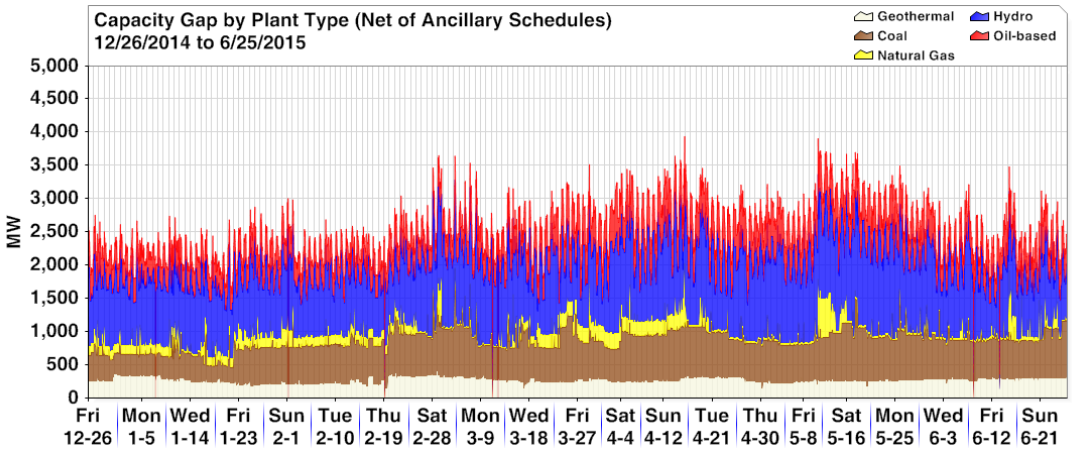

Figure 30 Capacity Gap - 1st Half

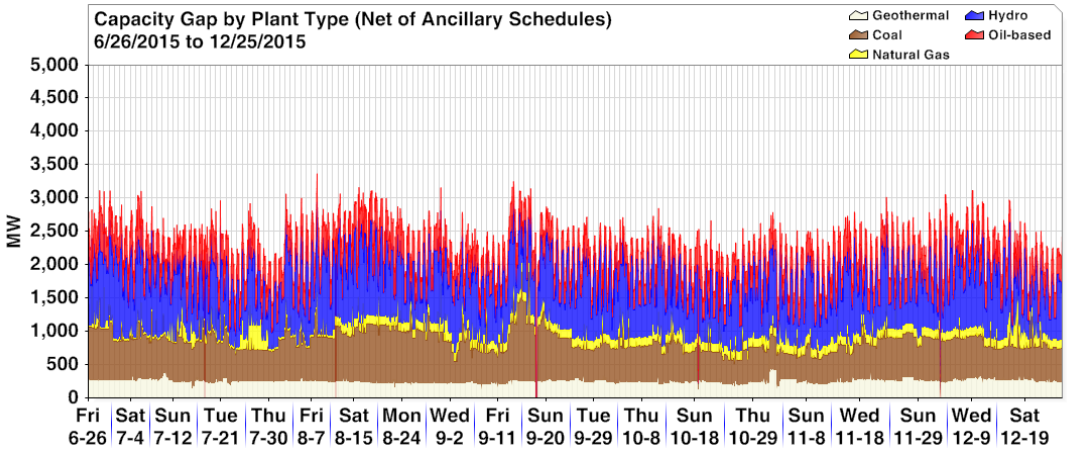

Figure 31 Capacity Gap - 2nd Half

Average Outage Gap by Billing Month (MW) - 2015							
Plant Type	Jan	Feb	Mar	Apr	May	Jun	Jul
Coal	405	605	678	685	684	653	669
Natural Gas	135	149	93	180	97	69	60
Geothermal	270	240	279	274	249	282	260
Hydro	969	900	1,089	1,098	1,301	1,001	880
Oil-Based	371	365	390	528	529	417	413
Total	2,149	2,259	2,529	2,766	2,860	2,420	2,282
continuation...	Aug	Sep	Oct	Nov	Dec	Annual Avg	
Coal	713	729	535	521	591	622	
Natural Gas	112	131	126	132	145	119	
Geothermal	243	235	235	253	269	257	
Hydro	876	817	836	821	800	948	
Oil-Based	405	338	311	342	371	398	
Total	2,348	2,250	2,038	2,069	2,176	2,344	

Table 39 Capacity Gap

	Year-onYear Average Capacity Gap Comparision by Billing Month						
	Jan	Feb	Mar	Apr	May	Jun	Jul
2015 (MW)	2,149	2,259	2,529	2,766	2,860	2,420	2,282
2014 (MW)	2,021	1,760	2,025	2,398	2,388	2,580	2,091
Y-Y (%) Change	6.3	28.4	24.9	15.4	19.7	(6.2)	9.1
continuation...	Aug	Sep	Oct	Nov	Dec	Annual Avg	
2015 (MW)	2,348	2,250	2,038	2,069	2,176	2,344	
2014 (MW)	2,481	2,185	2,28	2,231	2,280	2,228	
Y-Y (%) Change	(5.4)	3.0	(10.6)	(7.2)	(4.6)	5.2	

Table 40 Year-on-Year Average Capacity Gap Comparison

Similar to the trend system-wide, bulk of the capacity gap in the Luzon region is attributed to hydro plants, accounting for 48.2 percent of the region's total capacity gap at an average of 948 MW.

When compared to the previous year, however, capacity gap in Luzon registered a slight 0.7 percent decrease from last year's average of 1,953 MW to 1,966 MW this year. All resource types, except for coal and natural gas plants, registered decrease in their capacity gap levels on a year-on-year comparison. Coal plants demonstrated a 64.4 percent year-on-year increase averaging at 573 MW from last year's 348 MW while natural gas plants recorded a 146.3 percent increase at an average of 119 MW from 49 MW in 2014. Hydro, geothermal and oil-based plants all recorded decreases in their respective capacity gap levels at 14.4 percent (from 1,108 MW to 948 MW), 11.9 percent (from 149 MW to 132 MW) and 35 percent (from 299 MW to 194 MW), respectively. Nevertheless, capacity gap levels were still high throughout the year, denoting that generator-trading participants continued to submit offers less than their maximum available capacity.

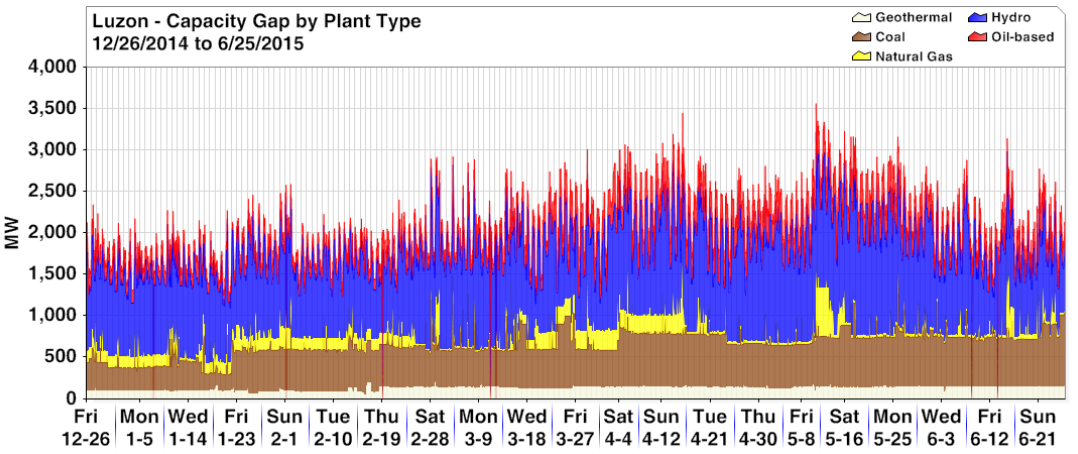

Figure 32 Capacity Gap (Luzon) - 1st Half

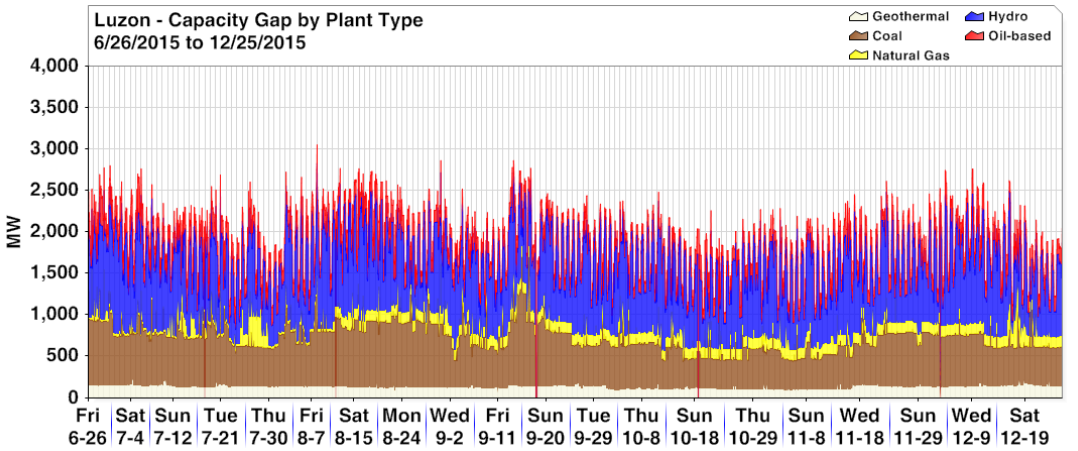

Figure 33 Capacity Gap (Luzon) - 2nd Half

Average Capacity Gap by Billing Month (MW) - Luzon, 2015							
Plant Type	Jan	Feb	Mar	Apr	May	Jun	Jul
Coal	352	517	552	600	601	639	666
Natural Gas	135	149	93	180	97	69	60
Geothermal	102	109	140	149	144	150	146
Hydro	969	900	1,089	1,098	1,301	1,001	880
Oil-Based	154	144	165	305	317	208	216
Total	1,712	1,818	2,039	2,331	2,460	2,067	1,968
continuation...	Aug	Sep	Oct	Nov	Dec	Annual Avg	
Coal	696	701	491	495	565	573	
Natural Gas	112	131	126	132	145	119	
Geothermal	134	133	116	115	144	132	
Hydro	876	817	836	821	800	948	
Oil-Based	206	154	130	157	175	194	
Total	2,023	1,936	1,699	1,720	1,830	1,966	

Table 41 Capacity Gap - Luzon

	Year-onYear Average Capacity Gap Comparision by Billing Month - Luzon						
	Jan	Feb	Mar	Apr	May	Jun	Jul
2015 (MW)	1,712	1,818	2,039	2,331	2,460	2,067	1,968
2014 (MW)	2,021	1,760	2,025	1,994	1,960	2,154	2,435
Y-Y (%) Change	(15.3)	3.3	0.7	16.9	25.5	(4.1)	(19.2)
continuation...	Aug	Sep	Oct	Nov	Dec	Annual Avg	
2015 (MW)	2,023	1,936	1,699	1,720	1,830	1,966	
2014 (MW)	2,005	1,730	1,859	1,816	1,839	1,953	
Y-Y (%) Change	0.9	11.9	(8.6)	(5.3)	(0.5)	0.7	

Table 42 Year-on-Year Average Capacity Gap Comparison - Luzon

In the Visayas, oil-based plants accounted for 53.8 percent of the total capacity gap in the region at an average of 204 MW, followed by geothermal plants with an average capacity gap of 126 MW, comprising of about 33.2 percent of the total capacity gap in the Visayas, while the remaining 13 percent is attributed to coal plants, with an average capacity gap of 49 MW.

Year-on-year comparison showed a decrease of 14.2 percent from last year's average of 443 MW to 380 MW this year, mainly on account of the decrease in the capacity gap of geothermal plants by about 25.3 percent, from an average of 169 MW in 2014. Coal plants similarly recorded a decline by about 8.9 percent from last year's average of 54 MW, while oil-based plants registered a decrease by 7 percent, from an average of 220 MW.

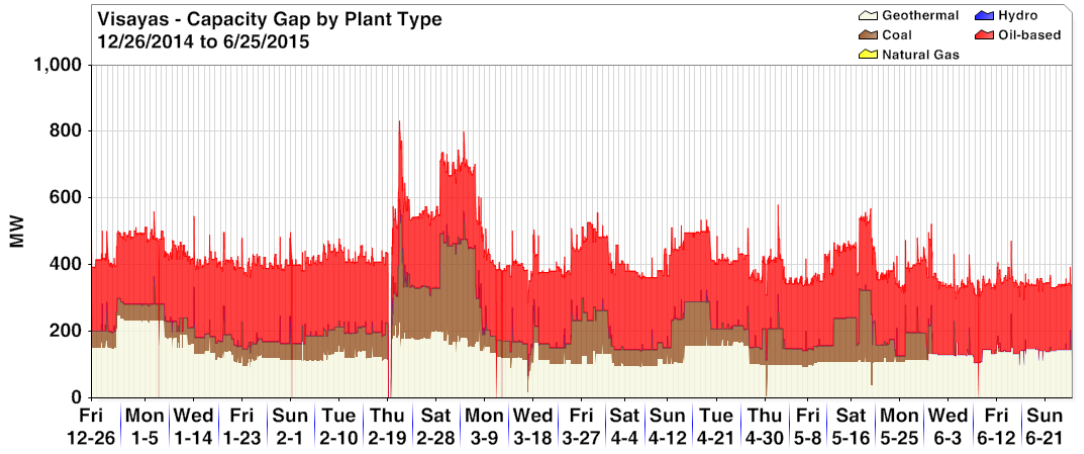

Figure 34 Capacity Gap (Visayas) - 1st Half

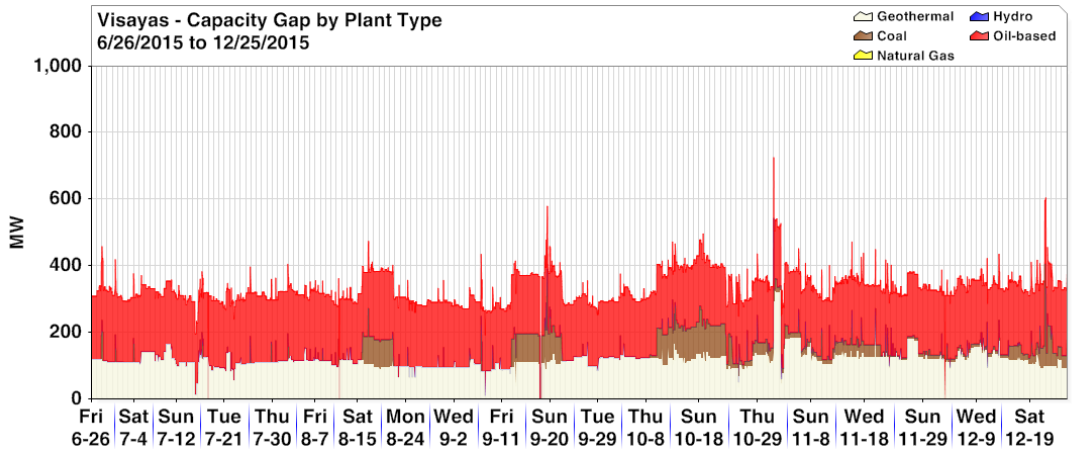

Figure 35 Capacity Gap (Visayas) - 2nd Half

	Average Capacity Gap by Billing Month (MW) - Visayas, 2015												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Avg.
Coal	52	90	126	86	83	15	2	17	28	46	26	26	49
Geothermal	168	134	139	126	105	133	114	109	103	120	138	126	126
Oil-Based	217	225	226	223	211	209	197	199	184	182	185	195	204
Total	437	449	490	435	399	356	314	325	315	348	350	347	380

Table 43 Capacity Gap - Visayas

	Year-on-Year Average Capacity Gap Comparison by Billing Month - Visayas									
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Avg.
2015 (MW)	86	83	15	2	17	28	46	26	26	49
2014 (MW)	126	105	133	114	109	103	120	138	126	126
Y-Y (%) Change	223	211	209	197	199	184	182	185	195	204

Table 44 Year-on-Year Average Capacity Gap Comparison - Visayas

MARKET PRICE OUTCOME[19]

MARKET PRICES

Market prices were generally lower this year when compared to the previous year, averaging at PhP3,824/MWh, from PhP4,835/MWh in 2014. It is noted that no imposition of the secondary cap[20] was made all throughout the year.

At the start of the billing year, the 20 percent increase threshold for weekly average prices was breached in all weeks of the January billing month, following the increasing trend in market prices during the period. Said increase is driven by the rise in outage capacity in January, particularly from major coal plants which were mostly on planned outage. Market prices averaged at PhP3,381/MWh in January and continued to rise by about 50.9 percent in February as system-wide market prices averaged at PhP5,101/MWh. Price spikes were observed on 11 to 12 February when supply margin was relatively narrow, as well as on 24 February at 1600H due to supply insufficiency.

Better supply and demand condition was experienced for the most part of March, resulting in the minimal increase of 0.1 percent during the period, with market prices averaging at PhP5,105/MWh. It was noted that prices were particularly higher at the start of the March billing month considering the high outage capacity among large coal plants at this time. Consequently,

19 The market prices were represented by the following: (i) ex-ante load weighted average price (LWAP) for trading intervals without pricing error during ex-ante, (ii) ex-post LWAP for trading intervals with pricing error during ex-ante but without pricing error during ex-post, (iii) LWAP based on the market re-run result for trading intervals with pricing error both during ex-ante and ex-post, (iv) administered price for loads for trading intervals under market intervention, and (v) estimated load reference price (ELRP) for trading intervals where the ERC-approved Price Substitution Mechanism (PSM) was applied.

20 ERC Resolution No. 20, series of 2014 entitled “Adopting and Establishing a Pre-Emptive Mitigation Measure in the WESM” sets the cumulative price threshold (CPT) equivalent to an average spot price of PhP9,000/MWh over a rolling 7-day period or 168 trading intervals. A breach of the CPT triggers the imposition of a price cap amounting to PhP6,245/MWh.

market prices reached a high of PhP24,800/MWh on 28 February at 0100H. The insufficiency in cheaper-priced capacities paved the way for the dispatch of the higher-priced offers from oil-based plants, such as Bauang, Limay, Therma Mobile, TPC (Carmen), and CPPC and hydro plants Magat and Angat. Price spikes were also observed on 13 March from 1200H to 1600H, 1900H, and from 2200H to 2300H, with prices ranging from PhP16,354/MWh to PhP28,631/MWh due to tight supply, following the unavailability of Sual 1 and 2 as well as Sta. Rita 1.

Major coal plants which were on outage resumed operations before the Malampaya facility went on shutdown on 15 March. Owing to increased supply availability during this period, market price levels were relatively lower, averaging at PhP3,7778/MWh, lower than the PhP6,003/MWh recorded during the period 26 February to 14 March. In addition, while there were occurrences of forced outages during the Malampaya shutdown, these were of short duration only. Malaya 2, meanwhile, which was called to run by the System Operator on 16 to 20 March, affecting a total of 106 trading intervals, provided a maximum of additional 130 MW capacity.

In April, market prices further declined by about 44.7 percent to PhP2,824/MWh following the decrease in the capacity on outage involving coal plants this month. It may be recalled that the unavailability of cheaper-priced offers from coal plants in the previous months resulted in the dispatch of the higher-priced oil-based plants. During this billing month, however, coal plants were able to set prices more often.

Significant high demand led to the 59.8 percent increase in the system-wide market prices in May, averaging at PhP4,512/MWh. Notwithstanding, the same is observed to be lower when compared to previous year's PhP6,302/MWh. Occurrences of price spikes were observed during twelve (12) evening off-peak intervals on 11-12, 14-15, 17, 19 and 21 May, as market prices surged above PhP16,000/KWh. These occurred as additional capacities, mostly from hydro plants, were shifted to ancillary services resulting in the dispatch of the higher-priced capacity offers of oil-based plants. It is noted that some oil-based plants usually submit offers at higher prices during the evening off-peak hours. Supply levels during the evening off-peak hours were likewise influenced by other factors. The SPEX-Malampaya gas restriction affected the output of natural gas plants from 11 to 15 May, particularly during the evening off-peak on 11-12 and 14 May when the 2x600 MW Ilijan plant was limited to a maximum 611 MW on 11-12 May and 607 MW on 14 May. On the other hand, on 17 May, decline in the capacity offers of Sual Unit 1 to 225 MW were noted from trading intervals 1400H to 2100H due to lube oil motor bearing damage. Meanwhile, the offered capacity of QPPL was noted to have reduced from 456 MW to 270 MW during trading intervals 2200H to 2400H on 21 May. Evening off-peak price spikes in May ranged from PhP16,965/MWh to a high of PhP24,947/MWh.

In June, the monthly system-wide average market price significantly rose by 41.9 percent, to PhP6,402/MWh. The same is an increase by 10.9 percent from the previous year's PhP5,772/MWh. Evidently high market prices were observed during the first week of the June billing month. Aside from the price spikes during peak hours, occurrences of high prices, ranging from PhP16,186/MWh to PhP24,967/MWh, were likewise observed during sixteen (16) evening off-peak intervals on 02,12,14-15,17, 20 and 23-25 June 2015. Tight supply conditions were noted during these trading intervals driven by factors such as capacity gap level, as well as the high outage capacity among major coal plants (due to equipment related problems) and natural gas plants (due to Malampaya gas restriction). This resulted in the dispatch of capacity offers of oil-based plants which were noticeably priced higher during off-peak intervals.

The decrease in demand in the July billing month resulted in significantly lower market prices by 30.1 percent averaging at PhP4,473/MWh, and by 44.7 percent from last year's 7,027/MWh. Market prices followed a decreasing trend until September, averaging at PhP3,729/

MWh and PhP2,168/MWh in August and September, respectively, as a result of the better supply conditions that prevailed throughout these months. It is noted that the September billing month posted the lowest monthly average market price this year. Average market prices went slightly up in October at PhP3,249/MWh, influenced by the lower effective supply levels recorded during the period. Nevertheless, the same is still lower by 22.4 percent from last year's PhP3,268/MWh.

Tighter supply and demand condition during the November billing month led to a 28.1 percent increase in the system-wide market prices, averaging at PhP3,249/MWh. Finally, drop in market prices were observed in December averaging at PhP2,487/MWh. This was 23.5 percent lower when compared to the previous month but still higher by 13.7 percent when compared to the previous year, posted at PhP2,186/MWh.

Maximum and Minimum Prices

The maximum price on record was posted at PhP30,234/MWh on 29 May at 1400H, coinciding with the forced outage of major coal plant Pagbilao 1 on top of the existing forced outage of coal plant SLTEC during the month.

On the other hand, market prices went as low as PhP-953/MWh on 26 December at 0700H. Negative prices were similarly noted in 24 trading intervals throughout the billing year, all of which were posted during morning off-peak hours. Nonetheless, the frequency of the occurrence of negative prices reduced from 45 events in the previous year. Last year's minimum market price was posted PhP-84,433/MWh on 25 December 2014 at 0700H.

Market Prices in Luzon and Visayas

In Luzon, market prices averaged at PhP3,791/MWh, lower by about 21.6 percent than the previous year's average price of PhP54.835/MWh.

Market prices in the Visayas, on the other hand, was lower by 1.7 percent from last year's average price of PhP4,087/MWh.

Month-on-month comparison of Luzon and Visayas prices showed that market prices are higher in the Visayas all throughout the billing year, except during the July and December billing months. Luzon market prices is said to be generally lower by about 5.7 percent than those in the Visayas. It is observed however, that the higher market prices in the Visayas were not necessarily on account of higher offer prices in the region, but due to the imposition of regional pricing error notices (PENs) and the application of the corresponding substitute prices in Luzon.

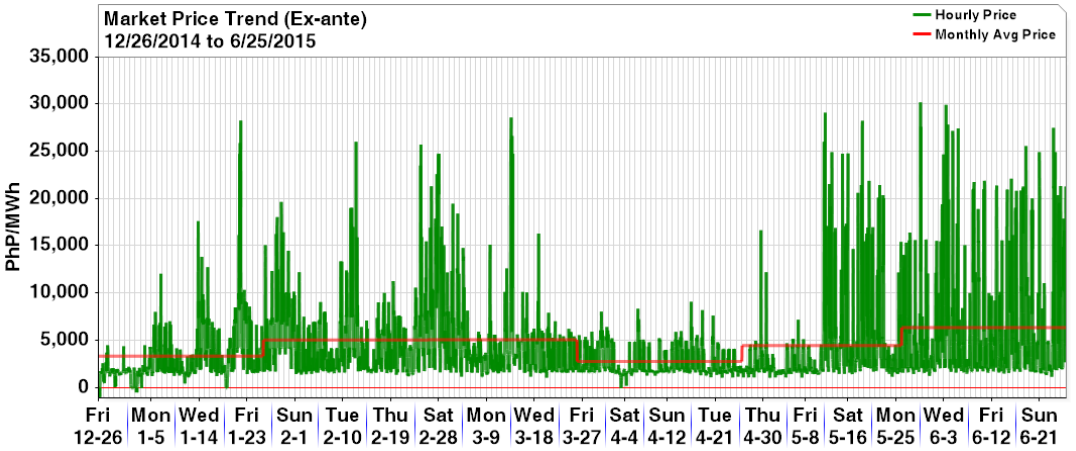

Figure 36 Market Price Trend - 1st Half

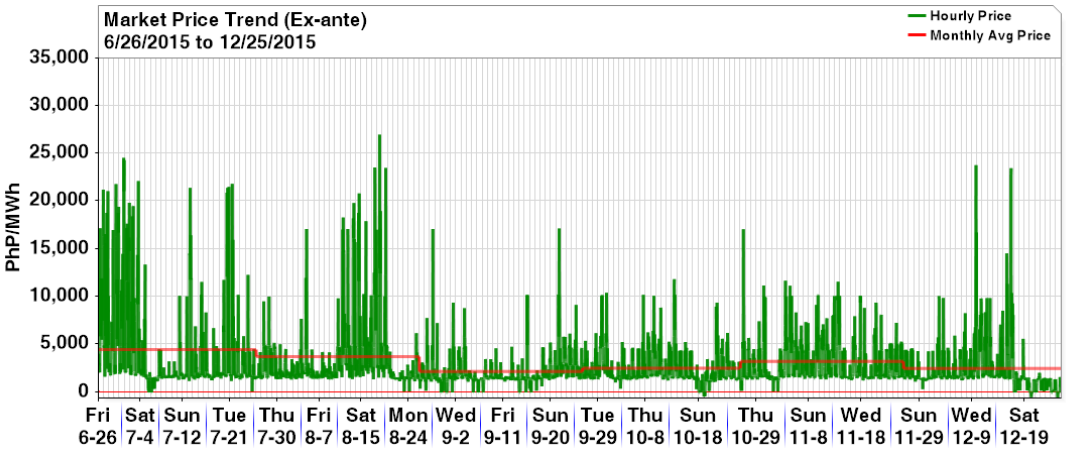

Figure 37 Market Price Trend - 2nd Half

	Market Price Trend by Billing Month (PhP/MWh) - 2015						
	Jan	Feb	Mar	Apr	May	Jun	Jul
Max Price	28,303	26,063	28,631	9,124	29,131	30,234	24,550
Min Price	(953)	1,249	1,103	0	1,109	1,202	0
Avg Price	3,381	5,101	5,105	2,824	4,512	6,402	4,473
continuation...	Aug	Sep	Oct	Nov	Dec	Annual Avg	
Max Price	26,975	17,155	11,848	17,083	23,777	30,234	
Min Price	102	0	(426)	102	(551)	(953)	
Avg Price	3,729	2,168	2,536	3,249	2,486	3,824	

Table 45 Market Price Trend - System

	Year-on-Year Market Price Trend Comparison by Billing Month - 2014						
	Jan	Feb	Mar	Apr	May	Jun	Jul
2015 (PhP/MWh)	3,381	5,101	5,105	2,824	4,512	6,402	4,473
2014 (PhP/MWh)	2,478	2,668	6,339	9,416	6,302	5,772	7,027
Y-Y (%) Change	36.4	91.2	(19.5)	(70.0)	(28.4)	10.9	(36.3)
continuation...	Aug	Sep	Oct	Nov	Dec	Annual Avg	
2015 (PhP/MWh)	3,729	2,168	2,536	3,249	2,486	3,824	
2014 (PhP/MWh)	5,317	4,028	3,268	3,348	2,186	4,835	
Y-Y (%) Change	(29.9)	(46.2)	(22.4)	(3.0)	13.7	(20.9)	

Table 46 Year-on-Year Average Price Trend Comparison - System

Evening Off-Peak Price Spikes			
Date	Trading Interval	LWAP (PhP/MWh)	Marginal Plant
11-May-15	2200H	17,143	Bauang DPP
12-May-15	2200H	24,947	Limay CCGT
	2300H	18,293	Navotas DPP
14-May-15	2200H	24,801	Navotas DPP
	2300H	16,965	Bauang DPP
15-May-15	2200H	19,154	Navotas DPP
	2300H	24,826	Navotas DPP
17-May-15	2100H	17,496	Bauang DPP
19-May-15	2200H	21,924	Navotas DPP
	2300H	18,021	Navotas DPP
21-May-15	2200H	21,473	Navotas DPP
	2300H	18,052	Navotas DPP
2-Jun-15	2200H	24,724	Navotas DPP
12-Jun-15	2100H	20,949	Limay CCGT
	2200H	21,419	Navotas DPP
	2300H	16,890	Bauang DPP
	2400H	16,828	Bauang DPP
14-Jun-15	2100H	20,971	Bauang DPP
	2200H	21,012	Navotas DPP
15-Jun-15	2200H	16,186	Limay CCGT
17-Jun-15	2200H	21,324	Navotas DPP
	2300H	16,840	Bauang DPP
20-Jun-15	2200H	24,966	Navotas DPP
	2300H	21,317	Limay CCGT
	2400H	20,397	Bauang DPP
23-Jun-15	2200H	24,967	Navotas DPP
24-Jun-15	2200H	21,372	Navotas DPP
25-Jun-15	2200H	21,319	Limay CCGT

Table 47 Summary of Evening Off-Peak Price Spikes, 2015

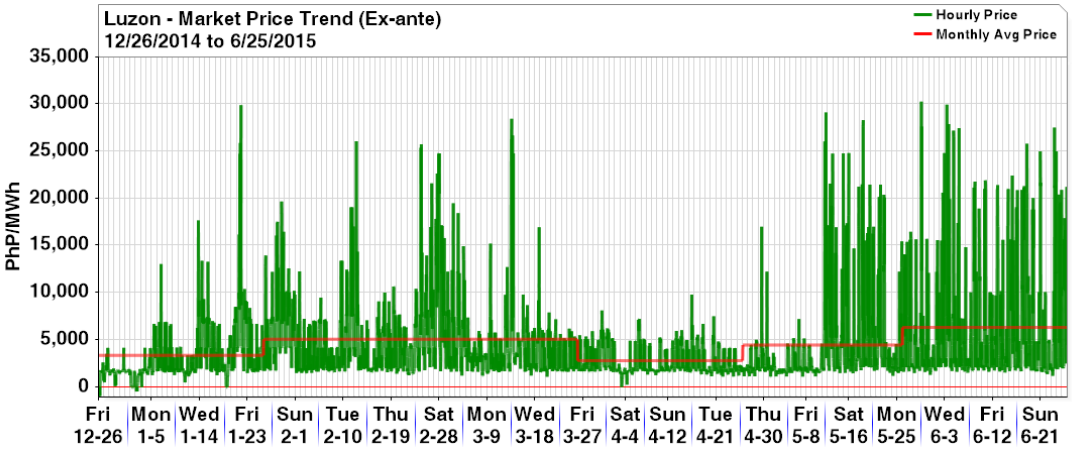

Figure 38 Market Price Trend (Luzon) - 1st Half

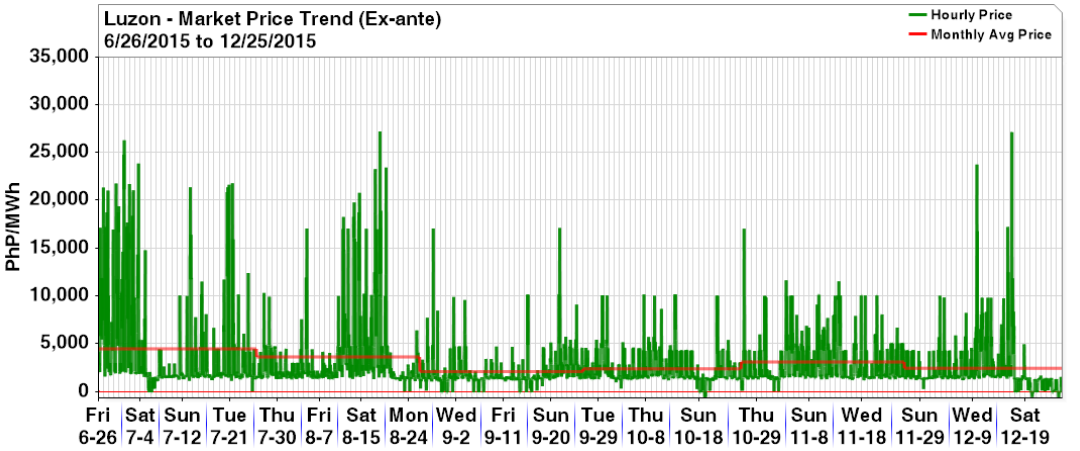

Figure 39 Market Price Trend (Luzon) - 2nd Half

	Market Price Trend by Billing Month (PhP/MWh) - Luzon, 2015						
	Jan	Feb	Mar	Apr	May	Jun	Jul
Max Price	29,900	26,063	28,457	9,816	29,131	30,273	26,329
Min Price	(972)	1,249	1,103	0	1,109	1,202	0
Avg Price	3,367	5,079	5,075	2,810	4,457	6,322	4,518
continuation...	Aug	Sep	Oct	Nov	Dec	Annual Avg	
Max Price	27,251	17,155	10,206	17,083	27,179	30,273	
Min Price	102	0	(508)	102	(551)	(972)	
Avg Price	3,691	2,157	2,454	3,158	2,491	3,791	

Table 48 Market Price Trend - Luzon

	Year-on-Year Market Price Trend Comparison by Billing Month - Luzon						
	Jan	Feb	Mar	Apr	May	Jun	Jul
2015 (PhP/MWh)	3,367	5,079	5,075	2,810	4,457	6,322	4,518
2014 (PhP/MWh)	2,478	2,668	6,339	9,416	6,302	5,772	7,027
Y-Y (%) Change	35.9	90.4	(19.9)	(70.2)	(29.3)	9.5	(35.7)
continuation...	Aug	Sep	Oct	Nov	Dec	Annual Avg	
2015 (PhP/MWh)	3,691	2,157	2,454	3,158	2,491	3,791	
2014 (PhP/MWh)	5,317	4,028	3,268	3,348	2,186	4,835	
Y-Y (%) Change	(30.6)	(46.5)	(24.9)	(5.7)	13.9	(21.6)	

Table 49 Year-on-Year Average Price Trend Comparison - Luzon

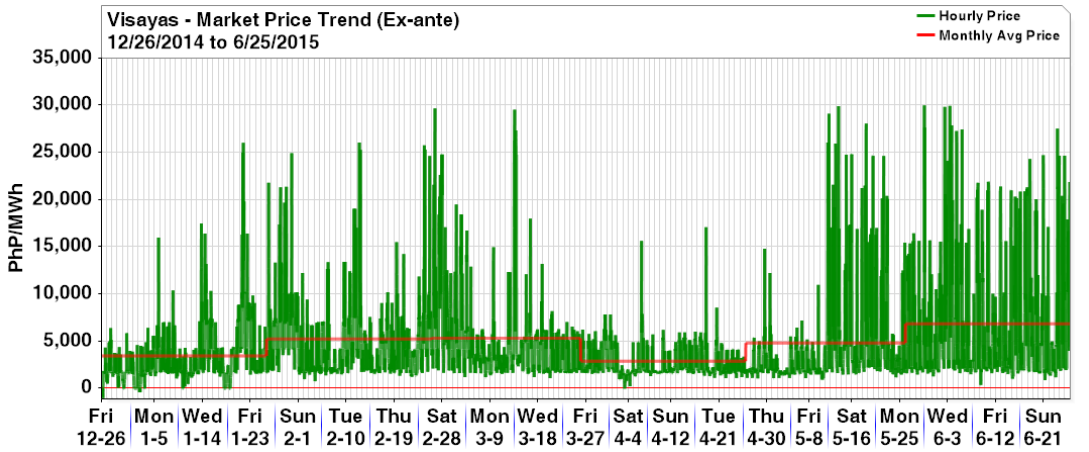

Figure 40 Market Price Trend (Visayas) - 1st Half

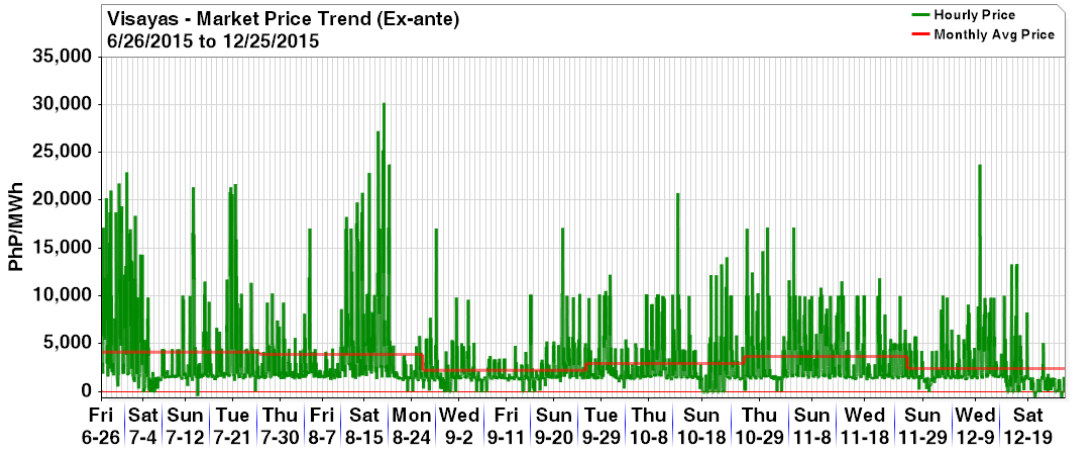

Figure 41 Market Price Trend (Visayas) - 2nd Half

	Market Price Trend by Billing Month (PhP/MWh) - Visayas, 2015						
	Jan	Feb	Mar	Apr	May	Jun	Jul
Max Price	26,043	26,063	29,685	17,093	29,920	30,003	22,980
Min Price	(1,001)	799	1,103	0	957	386	-401
Avg Price	3,474	5,260	5,328	2,905	4,839	6,871	4,190
continuation...	Aug	Sep	Oct	Nov	Dec	Annual Avg	
Max Price	30,236	17,155	20,813	17,217	23,777	30,236	
Min Price	102	0	(50)	102	(551)	(1,001)	
Avg Price	3,953	2,277	2,999	3,736	2,470	4,019	

Table 50 Market Price Trend - Visayas

	Year-on-Year Market Price Trend Comparison by Billing Month - Visayas						
	Jan	Feb	Mar	Apr	May	Jun	Jul
2015 (PhP/MWh)	3,474	5,260	5,328	2,905	4,839	6,871	4,190
2014 (PhP/MWh)	3,616	3,916	3,367	6,377	6,618	5,741	6,965
Y-Y (%) Change	(3.9)	34.3	58.3	(54.5)	(26.9)	19.7	(39.8)
continuation...	Aug	Sep	Oct	Nov	Dec	Annual Avg	
2015 (PhP/MWh)	3,953	2,277	2,999	3,736	2,470	4,019	
2014 (PhP/MWh)	4,389	(380)	1,706	3,874	2,848	4,087	
Y-Y (%) Change	(9.9)	(698.6)	75.8	(3.6)	(13.3)	(1.7)	

Table 51 Monthly Average Price Comparison - Visayas

FREQUENCY AND DISTRIBUTION

Majority or about 47.4 percent of the market prices this year were distributed to prices below PhP2,000/MWh. On the other hand, prices ranging from the above PhP2,000/MWh to PhP4,000/MWh level comprised about 22.5 percent of the market prices for 2015, while about 17.1 percent were prices ranging from above PhP4,000/MWh to PhP6,000/MWh. On the other hand, prices above PhP6,000/MWh to PhP8,000 averaged at 5 percent this year; above PhP8,000/MWh to PhP10,000/MWh, at 1.9 percent; while prices above PhP10,000/MWh comprised about 6 percent of the market prices, with 1.1 percent of which comprised of prices above PhP20,000/MWh.

When compared with other billing months, the billing months of May, June and July demonstrated higher frequency in the distribution of prices at the above PhP10,000/MWh and above PhP20,000/MWh level. These correspond to the higher market prices which were observed during these months and manifested in the increase in the distribution of prices ranging above PhP10,000/MWh to PhP20,000/MWh, at 6,9 percent, 13.2 percent and 11 percent, respectively. For prices above PhP20,000/MWh, the same comprised 2.1 percent, 5.4 percent and 1.7 percent, respectively, during said months, higher than the average price distribution of 1.1 percent throughout the billing year.

Also, the frequency of prices distributed to higher price ranges during the February and March billing months were above the typical price distribution for the year. Thus, these months incurred increases in the distribution of prices within the range of above PhP10,000/MWh to PhP20,000/MWh, averaging at 7 percent and 7.6 percent, respectively. Furthermore, prices

above PhP20,000/MWh during these months were posted at 0.4 percent and 1.9 percent, respectively.

On the other hand, low market prices in September corresponded to the price distribution trend during said month, with about 72.8 percent of the prices falling below PhP2,000/MWh.

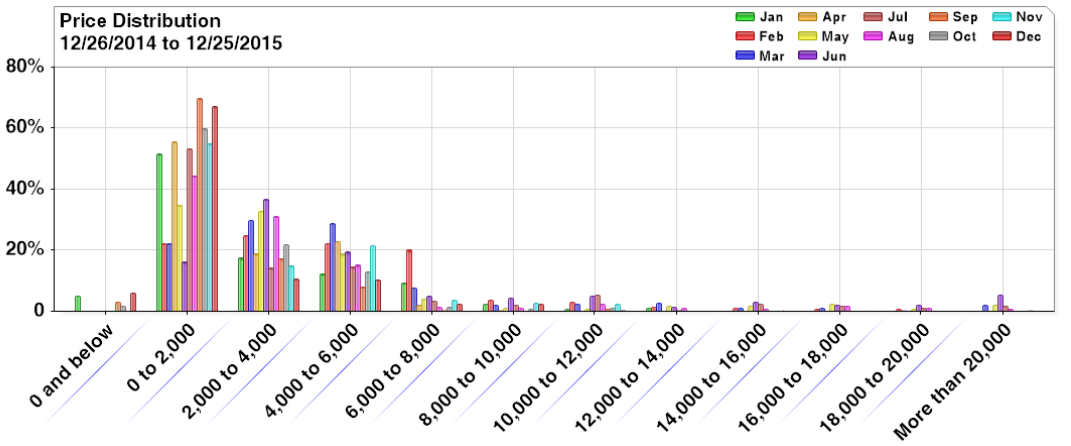

Figure 42 Monthly Market Price Distribution

Market Price Distribution by Billing Month (%) - 2015													
Price Range (PhP/MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Avg.
0 & Below	5.1	0.0	0.0	0.1	0.0	0.0	0.1	0.0	3.0	1.8	0.0	6.0	1.3
0 to 2,000	51.5	22.0	22.0	55.6	34.6	16.1	53.3	44.4	69.9	60.0	55.0	67.2	46.1
2,000 to 4,000	17.5	24.7	29.9	19.0	32.8	36.6	14.2	30.9	17.3	21.9	14.9	10.6	22.5
4,000 to 6,000	12.1	22.3	28.7	22.8	18.8	19.5	14.4	15.1	7.8	13.1	21.6	10.3	17.1
6,000 to 8,000	9.1	20.0	7.7	1.9	3.9	4.8	3.2	1.5	0.5	1.4	3.5	2.4	5.0
8,000 to 10,000	2.2	3.5	2.1	0.5	1.0	4.4	2.1	1.1	0.4	0.7	2.6	2.2	1.9
10,000 to 12,000	0.8	3.0	2.4	0.0	0.7	5.0	5.4	2.2	0.8	1.1	2.0	0.6	2.0
12,000 to 14,000	0.9	1.5	2.7	0.0	1.7	1.5	0.6	0.9	0.0	0.0	0.0	0.0	0.8
14,000 to 16,000	0.0	1.1	1.0	0.0	1.5	2.8	2.2	0.8	0.0	0.0	0.0	0.3	0.8
16,000 to 18,000	0.4	0.8	1.0	0.0	2.4	1.9	1.8	1.6	0.3	0.0	0.1	0.1	0.9
18,000 to 20,000	0.0	0.7	0.4	0.0	0.7	2.0	1.0	0.9	0.0	0.0	0.0	0.0	0.5
More than 20,000	0.4	0.4	1.9	0.0	2.1	5.4	1.7	0.7	0.0	0.0	0.0	0.4	1.1

Table 52 Monthly Market Price Distribution

Comparison of the price distribution between the Luzon and Visayas regions demonstrates that market prices in Visayas during the year were generally higher than the market prices in Luzon.

In Luzon, the frequency of market prices distributed below PhP2,000/MWh averaged at 48.9 percent during the billing year. The same is higher than the 47.5 percent posted in the Visayas. Also, market prices distributed between the above PhP10,000/MWh and above PhP20,000/MWh levels were correspondingly higher in the Visayas than in Luzon. About 6.1 percent of the market prices in Visayas were distributed at the above PhP10,000/MWh while these were posted at only 5.0 percent in Luzon. On the other hand, about 1.3 percent of the market prices in Visayas were at the above PhP20,000/MWh range, while these comprised only about 1.1 percent of the market prices in Luzon.

As already stated, the higher market prices in the Visayas were not necessarily on account of higher offer prices in the region, but due to the imposition of regional pricing error notices (PENs) and the application of the corresponding substitute prices in Luzon.

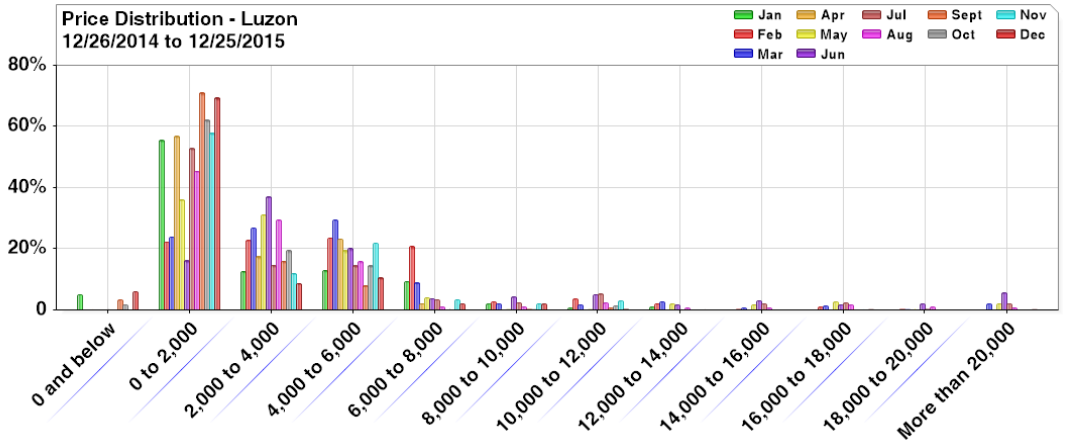

Figure 43 Monthly Market Price Distribution - Luzon

Market Price Distribution by Billing Month (%) - Luzon, 2015													
Price Range (PhP/MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Avg.
0 & Below	5.1	0.0	0.0	0.1	0.0	0.0	0.1	0.0	3.2	1.8	0.0	6.1	1.4
0 to 2,000	55.5	22.3	24.0	56.9	36.0	16.1	52.8	45.4	71.0	62.1	57.8	69.3	47.5
2,000 to 4,000	12.6	22.7	26.9	17.5	31.1	37.0	14.6	29.4	16.0	19.6	12.0	8.6	20.6
4,000 to 6,000	12.9	23.5	29.5	23.3	19.4	20.3	14.4	16.0	7.8	14.4	21.9	10.4	17.8
6,000 to 8,000	9.4	20.8	8.8	2.0	4.0	3.8	3.3	1.1	0.4	0.3	3.4	2.1	4.9
8,000 to 10,000	1.9	2.8	2.1	0.3	0.4	4.2	2.4	1.1	0.5	0.4	2.0	1.9	1.7
10,000 to 12,000	0.8	3.5	1.8	0.0	0.4	5.0	5.1	2.2	0.8	1.4	2.8	0.6	2.0
12,000 to 14,000	0.9	2.0	2.7	0.0	1.9	1.6	0.3	0.8	0.0	0.0	0.0	0.1	0.9
14,000 to 16,000	0.0	0.5	0.7	0.0	1.7	3.1	2.1	0.8	0.0	0.0	0.0	0.0	0.7
16,000 to 18,000	0.4	0.9	1.2	0.0	2.6	1.6	2.2	1.6	0.3	0.0	0.1	0.4	0.9
18,000 to 20,000	0.0	0.5	0.4	0.0	0.3	1.9	0.6	0.9	0.0	0.0	0.0	0.0	0.4
More than 20,000	0.4	0.4	1.9	0.0	2.1	5.5	2.1	0.7	0.0	0.0	0.0	0.4	1.1

Table 53 Monthly Market Price Distribution - Luzon

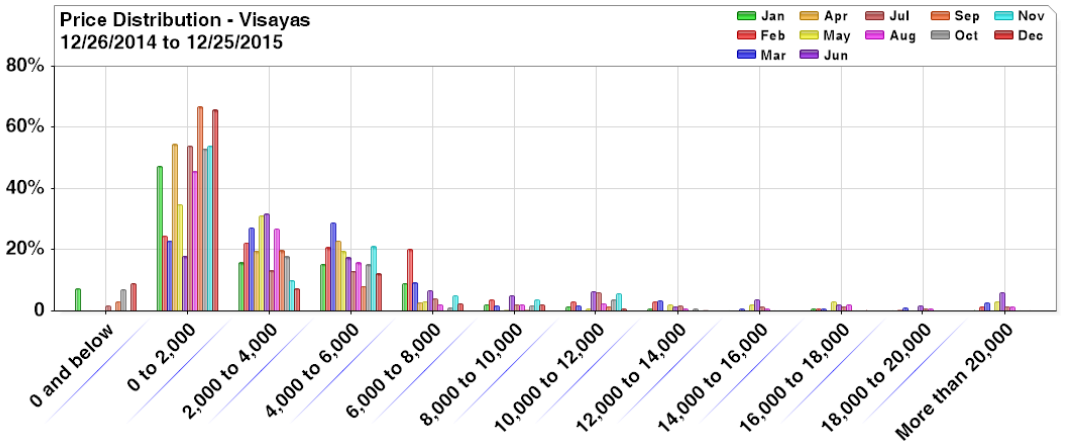

Figure 44 Monthly Market Price Distribution - Visayas

Market Price Distribution by Billing Month (%) - Visayas, 2015													
Price Range (PhP/MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Avg.
0 & Below	7.3	0.0	0.0	0.1	0.0	0.0	1.5	0.0	3.0	6.9	0.0	9.0	2.3
0 to 2,000	47.3	24.5	22.8	54.4	34.9	17.9	54.0	45.6	66.8	52.9	54.0	65.7	45.2
2,000 to 4,000	15.7	22.3	27.2	19.6	31.1	31.7	13.2	26.9	19.8	17.8	9.9	7.2	20.2
4,000 to 6,000	15.3	20.7	28.9	22.8	19.6	17.5	13.1	15.7	8.1	15.1	21.1	12.1	17.4
6,000 to 8,000	9.0	20.3	9.2	2.6	3.1	6.7	3.9	2.0	0.4	0.8	5.0	2.4	5.4
8,000 to 10,000	2.0	3.5	1.6	0.1	0.6	5.0	2.1	2.0	0.5	1.8	3.6	2.1	2.1
10,000 to 12,000	1.3	3.0	1.8	0.0	0.7	6.3	6.1	2.4	1.2	3.5	5.6	0.7	2.7
12,000 to 14,000	0.8	2.8	3.4	0.0	2.1	1.5	1.5	0.7	0.0	0.7	0.1	0.4	1.2
14,000 to 16,000	0.1	0.4	0.7	0.1	1.9	3.8	1.3	0.8	0.0	0.1	0.1	0.0	0.8
16,000 to 18,000	0.7	0.8	0.7	0.1	3.1	1.9	1.3	2.0	0.3	0.1	0.4	0.3	1.0
18,000 to 20,000	0.1	0.5	1.0	0.0	0.1	1.7	0.7	0.7	0.0	0.0	0.0	0.0	0.4
More than 20,000	0.3	1.2	2.5	0.0	2.9	6.0	1.4	1.2	0.0	0.1	0.0	0.1	1.3

Table 54 Monthly Market Price Distribution - Visayas

SUPPLY MARGIN AND MARKET PRICE ANALYSIS

This section provides an analysis of market prices relative to the level of supply margin in the WESM.

Supply margin is defined as the MW difference between total offered capacity, duly considering security limit & ramp limitations, and system demand. As shown in Figure 45, the supply margin and price have an inverse relationship, that is: if the supply margin is low, prices tend to be high and conversely, if supply margin is high, market prices are low.

In 2015, there were 205 intervals (2.35 percent of the time) with supply margin of 100 MW and below with corresponding prices ranging from PhP4,854.31/MWh to PhP29,952.33/MWh. The highest price at PhP29,952.33//MWh was recorded on 03 June 2015 0900H with a supply margin of about 16 MW. On the other hand, there were 6,048 intervals (69.35 percent of the time) with supply margin greater than 1,000 MW. Prices during said intervals ranged from

PhP2,003.56/MWh up to PhP15,050.59/MWh. The lowest supply margin recorded in 2015 was at 0.01 MW on 16 March 2015, 1100H at PhP7,412.89/MWh.

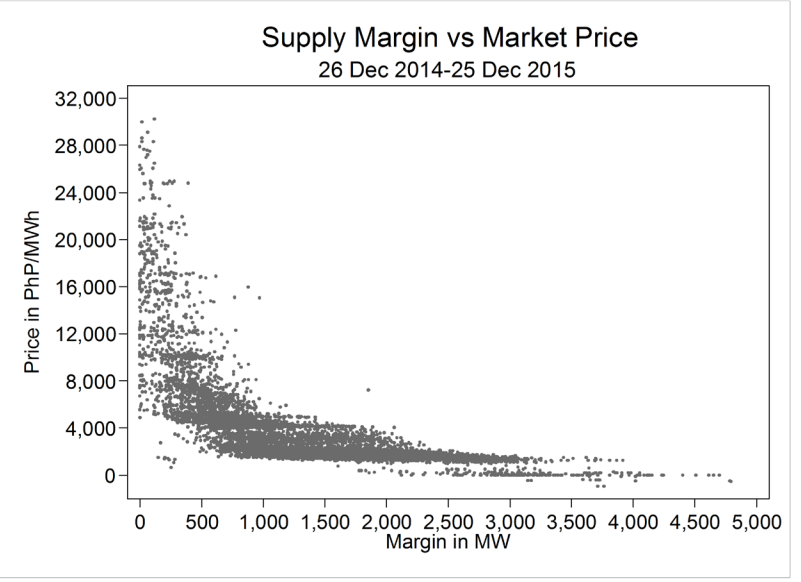

Figure 45 Supply Margin vs. Market Price

To further assess the relationship between supply margin and market prices, a supply margin analysis[21] was conducted to determine interesting pricing events. A combination of statistical methods namely, bandwidth method, ordinary least squares (OLS) method and non-parametric method was used to establish upper and lower price thresholds. The criteria used for this assessment were as follows: (a) Reference prices were derived using 2014 billing year market prices; (b) upper and lower thresholds of the reference price were computed using the ±3 standard deviations; and (c) periods having negative supply margins were excluded.

As shown in Figure 46, there were 39 intervals wherein prices went above the upper threshold during the billing year. Consistent with the foregoing discussion on market prices, it is observed that these interesting pricing events mostly occurred during periods of tight supply and demand conditions. On the other hand, there was no interval with prices that went beyond the lower threshold.

The most narrow supply margins were noted to have occurred during the January, May and June billing months. In January, a rise in outage capacity was noted, particularly from major coal plants which were mostly on planned outage. On the other hand, significant increase in demand mainly drove the narrow supply margins in the May and June billing months, while supply levels during several trading hours likewise dropped particularly during the period of the Malampaya gas restriction which started on 10 May.

In contrast, negative market prices were observed in December following the wide supply margins as demand levels dropped significantly while effective supply levels increased particularly during the last part of the December billing month.

21 The methodology used in this section is based on the methodology adopted by the Market Surveillance Administrator (MSA) of Alberta, Canada.

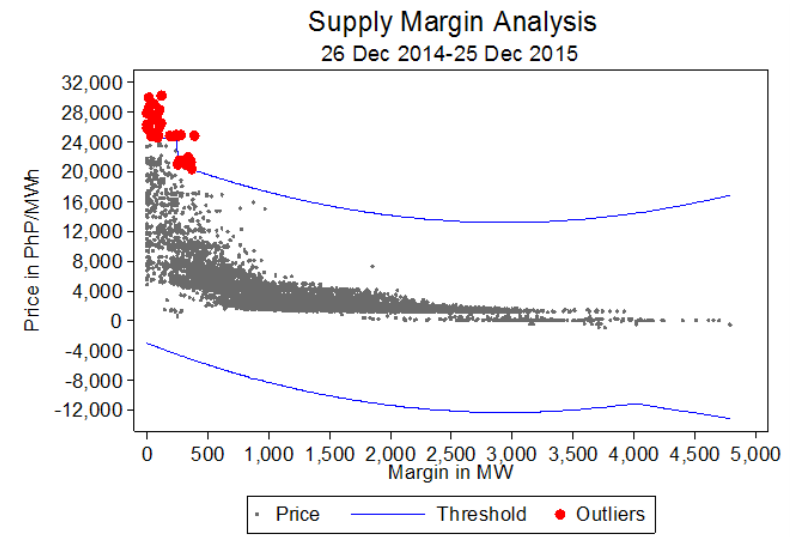

Figure 46 Supply Margin Analysis

Table 55 lists the interesting pricing events during the period. It can be observed that mostly oil-based plants were able to set prices at high levels or near the offer price cap (PhP 32,000/MWh) when the supply margin was low.[22]

Date	Hour	Market Price (PhP/MWh)	Supply Margin (MW)	Price Setters (Resource Name)
21-Jan-15	14	24,774.45	34.5	None (Pricing Error in both RTD and RTX)
21-Jan-15	16	25,921.00	0.7	Limay CCGT
21-Jan-15	19	28,302.52	107.5	Bauang DPP
12-Feb-15	11	26,063.04	104.3	Bauang DPP, Limay CCGT, Subic Power Corp
27-Feb-15	22	24,748.75	41.3	None (Pricing Error in both RTD and RTX)
27-Feb-15	23	24,776.63	86.4	Therma Mobile
28-Feb-15	1	24,800.41	391.1	Therma Mobile
13-Mar-15	14	26,292.87	0.7	None (Pricing Error in both RTD and RTX)
13-Mar-15	15	28,632.88	15.1	Bauang DPP, Limay CCGT
13-Mar-15	22	24,775.52	225.5	Therma Mobile
13-Mar-15	23	24,790.09	263.1	Therma Mobile
11-May-15	11	26,060.41	11.3	Limay CCGT, TPC Carmen
11-May-15	16	29,130.71	60.8	CEDC CFTPP, Limay CCGT
12-May-15	22	24,946.59	85.7	CEDC CFTPP, Therma Mobile
14-May-15	22	24,801.47	191.3	Bauang DPP, Therma Mobile
15-May-15	23	24,826.34	96.6	Therma Mobile
18-May-15	15	27,567.60	55.9	Limay CCGT
18-May-15	16	28,281.81	15.9	Limay CCGT, Bauang DPP
19-May-15	22	21,923.75	340.1	Bauang DPP, Therma Mobile
21-May-15	22	21,473.30	263.5	Bauang DPP, Therma Mobile

22 Interesting Pricing Event — Refers to intervals with prices which lie outside the resulting upper and lower thresholds. The term avoids having a negative and accusing tone but instead touches on the general intent of assessing a rather unusual event based on the relationship between supply margin and market price.

Date	Hour	Market Price (PhP/MWh)	Supply Margin (MW)	Price Setters (Resource Name)
29-May-15	14	30,233.89	117.0	Limay CCGT, Bauang DPP
29-May-15	16	27,641.41	30.1	Bauang DPP
2-Jun-15	22	24,724.29	198.4	Therma Mobile, TPC (Carmen)
3-Jun-15	9	29,952.33	15.8	Bauang DPP
3-Jun-15	17	27,886.32	0.6	Limay CCGT
4-Jun-15	15	27,217.08	61.3	Limay CCGT
4-Jun-15	16	26,486.52	114.3	Limay CCGT
5-Jun-15	16	27,467.12	82.6	Bauang DPP, Limay CCGT
12-Jun-15	22	21,419.09	296.2	Bauang DPP, Therma Mobile, TPC (Sangi)
14-Jun-15	22	21,012.24	318.0	Bauang DPP, kepco Ilijan, Limay CCGT, Therma Mobile, TPC (Sangi)
17-Jun-15	22	21,324.26	361.4	Bauang DPP, Limay CCGT, Therma Mobile, TPC (Sangi)
18-Jun-15	10	25,597.41	20.8	TPC (Carmen)
20-Jun-15	22	24,965.53	238.8	Bauang DPP, Therma Mobile
20-Jun-15	23	21,316.63	356.6	Bauang DPP, Limay CCGT
20-Jun-15	24	20,396.72	370.7	Bauang DPP, Cebu DPP I, Cebu DPP II, Limay CCGT
23-Jun-15	22	24,966.78	278.9	Bauang DPP, Therma Mobile
27-Jun-15	20	21,054.84	253.7	Bauang DPP, Limay CCGT
30-Jun-15	20	24,549.66	91.5	TPC (Carmen)
18-Aug-15	11	26,974.99	48.1	Navotas GTPP

Table 55 List of Interesting Price Events, 2015

While occurrence of high prices during low supply margin is a common feature in a liberalized electricity market, further assessment of the market conditions on hours with price outliers is needed to validate the reasonableness of high prices. It should be noted that while the supply margin analysis can serve as a tool in detecting interesting pricing events, it will not in itself determine definitively the existence of abuse of market power and possible conduct of anti-competitive behaviour.

MARKET INTERVENTION/SUSPENSION

The market intervention (MI) or suspension index is a general indicator used to assess the development of the WESM in relation to special conditions, which, under the WESM Rules, include emergency, system security threat, and force majeure events. Either the Market Operator (MO) or System Operator (SO) may declare/initiate market intervention depending on the emergency events. On the other hand, market suspension (MS) is an event wherein the ERC declares the operation of the spot market to be suspended in cases of natural calamities or national and international security emergencies. In the event of market intervention or suspension, the administered price[23] shall be used for WESM settlement.

23 Under the WESM Rules, the administered price shall be used for settlement in cases where there is intervention in the market by the System Operator or where the market is suspended by the ERC (WESM Rule 6.2.3 and 6.8.3.1). The administered price applies when the Market Operator is not able to generate or determine the price for energy for a grid or island grid for any given trading interval that intervention or suspension is in effect.

MI was declared system-wide and in the Luzon and Visayas regions, affecting a total of 36 trading intervals throughout billing year 2015. System-wide, market intervention events was imposed in 18 trading intervals this year, 17 of which were noted to be initiated by the MO, while the SO declared one MI event in January. System-wide MI events were mostly force majeure due to a Market Management System (MMS)[24] concern. On the other hand, 5 MI events were declared in Luzon. Of which, 4 are initiated by the SO and only 1 is initiated by the MO. The 4 SO-initiated MI events in the region during the October billing month were emergency/security events on account of the outage of San Jose – Tayabas 500kV Lines 1 and 2 caused by Typhoon "Lando". In the Visayas, 13 MI events were observed during the year, 12 of which were declared by the SO and 1 by the MO. These SO-declared MI events were attributable to the multiple tripping of transmission lines in the Visayas on 19 February.

It is likewise worthy to note that there was no declaration of MS throughout the year. It can be recalled that MS was declared by the ERC in the Visayas for the whole duration of the January to March billing months. This is on account of the destruction of the Visayas power system due to typhoon Yolanda which hit the region in November 2013.

When compared to the previous year, the frequency of MI/MS events during the year is significantly lower than the total of 2,463 MI/MW events in 2014. Note however, that the 2,160 events comprised of the ERC's MS declaration which affected the Visayas during the 1st quarter of 2014. This notwithstanding, the remaining 302 events which accounted for the MI events in the previous year was still notably higher when compared to the frequency of the MI events this year.

		2015												
Initiated by	Remarks (Luz-Vis)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
MO	Force Majeure (MMS Concern)		2				1	1	1	7				12
	Force Majeure (MO Other Concern)			4										4
	Force Majeure (SCADA/EMS Concern)												1	1
	Sub-Total (MO-Initiated)	0	2	4	0	0	1	1	1	7	0	0	1	17
NGCP-SO	Emergency/Security Event													0
	Force Majeure (SCADA/EMS Concern)	1												1
	Force Majeure (SO Other Concern)													0
	Sub-Total (NGCP-SO-Initiated)	1	0	0	0	0	0	0	0	0	0	0	0	1
ERC	Declaration of (Partial) Market Suspension													0
	Sub-Total (ERC-Initiated)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total		1	2	4	0	0	1	1	1	7	0	0	1	18

Table 56 Total Monthly Occurrences of Market Intervention

24 The MMS is the is the infrastructure that supports the WESM and the ancillary IS/IT facilities of the Market Operator.

2015														
Initiated by	Remarks (Luzon)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
MO	Force Majeure (MMS Concern)													0
	Force Majeure (MO Other Concern)						1							1
	Sub-Total (MO-Initiated)	0	0	0	0	0	1	0	0	0	0	0	0	1
NGCP-SO	Emergency/Security Event										4			4
	Force Majeure (SCADA/EMS Concern)													0
	Force Majeure (SO Other Concern)													0
	Sub-Total (NGCP-SO-Initiated)	0	0	0	0	0	0	0	0	0	0	0	0	4
ERC	Declaration of (Partial) Market Suspension													0
	Sub-Total (ERC-Initiated)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total		0	0	0	0	0	1	0	0	0	0	0	0	5

Table 57 Monthly Occurrences of Market Intervention - Luzon

2014														
Initiated by	Remarks (Visayas)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
MO	Force Majeure (MMS Concern)									1				1
	Force Majeure (MO Other Concern)													0
	Sub-Total (MO-Initiated)	0	0	0	0	0	0	0	0	1	0	0	0	1
NGCP-SO	Emergency/Security Event		12											12
	Force Majeure (SCADA/EMS Concern)													0
	Force Majeure (SO Other Concern)													0
	Sub-Total (NGCP-SO-Initiated)	0	12	0	0	0	0	0	0	0	0	0	0	12
ERC	Declaration of (Partial) Market Suspension													0
	Sub-Total (ERC-Initiated)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total		0	12	0	0	0	0	0	0	1	0	0	0	13

Table 58 Monthly Occurrences of Market Intervention/Suspension - Visayas

PRICE SETTING INDICES

PRICE SETTING FREQUENCY INDEX (PSFI)

The price setting indices identify generating plants that set the price or are near setting the spot prices. A generating plant is considered a price setter if its last accepted offer price is within 95 to 100 percent of the nodal price.

The figures and tables below show the generating plants that qualified as price setters as well as the frequency by which these plants became price setters by billing month throughout the billing year. The PSFI are determined for several price ranges.

Luzon coal plants Sual, Masinloc, Pagbilao and Mariveles dominated the list of price-setters across all price levels during the billing year followed by Visayas coal plants KSPC and PEDC and natural gas plants Ilijan in Luzon and Leyte A in Visayas.

Prices within the range of above PhP5,000/MWh were most frequently set by oil-based plants. Luzon plant Navotas and Visayas plant EAUC both topped the list, followed by Visayas oil-based plant PEDC, Luzon plant Bauang, Visayas plants Nabas and TPC (Carmen), Luzon plants Subic and TAPGC. Hydro plants Magat and Kalayaan likewise figured in the list of price setters during the billing year.

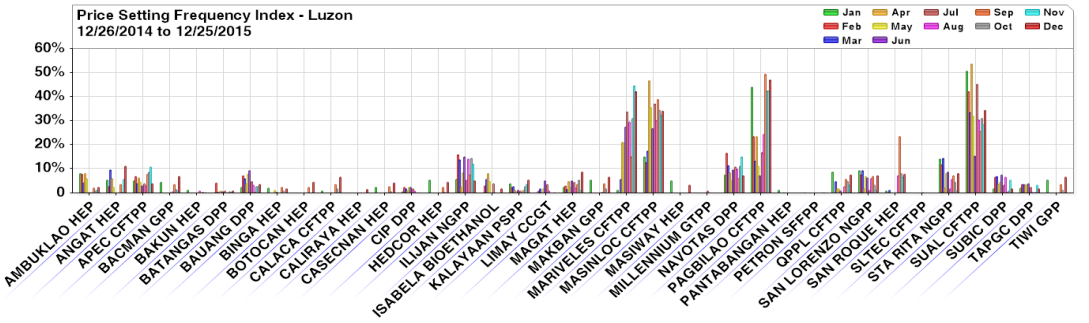

Figure 47 Price Setting Frequency Index - Luzon Plants

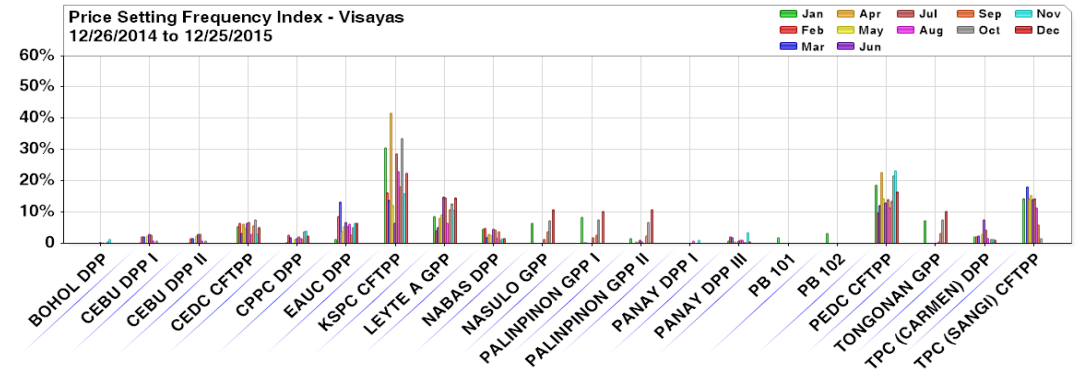

Figure 48 Price Setting Frequency Index - Visayas Plants

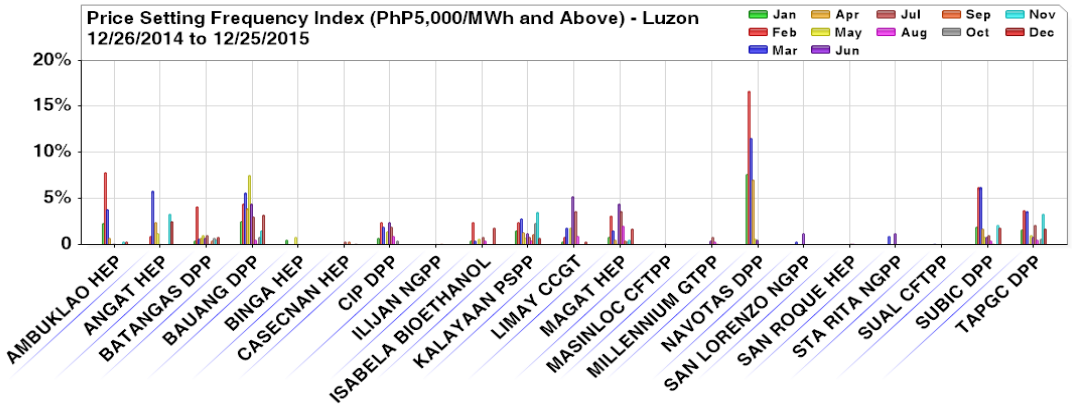

Figure 49 Price Setting Frequency Index - Luzon Plants (Above PhP5,000/MWh)

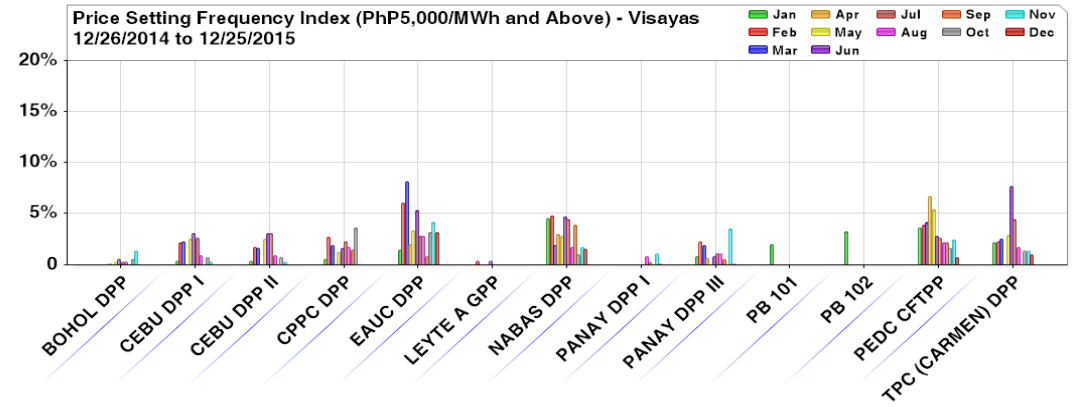

Figure 50 Price Setting Frequency Index - Visayas Plants (Above PhP5,000/MWh)

PSFI (%) by Billing Month - Luzon

Generating Plant	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
AMBUKLAO HEP	8.1	7.8	4.3	8.2	6.1	0.4	0.4	0.4	2.0	0.8	1.2	2.5
ANGAT HEP	5.4	2.8	9.5	5.9	2.4		0.1		3.8	0.6	5.8	11.3
APEC CFTPP	5.2	6.9	4.0	6.5	4.4	3.0	4.0	3.1	7.8	8.8	10.9	3.9
BACMAN GPP	4.4	0.1		0.1	0.1		0.4	.7	3.8	1.5	0.8	7.1
BAKUN HEP	1.3				0.1		0.1	0.9	0.3	0.6		0.3
BATANGAS DPP	0.4	4.2	0.6	0.7	1.0	0.7	1.0	0.1	0.4	0.7	0.5	0.8
BAUANG DPP	2.6	7.1	6.0	4.0	7.8	9.4	4.7	3.4	0.5	2.8	2.8	3.8
BINGA HEP	2.0			0.1	1.3	0.5	0.1		2.4	1.0	0.3	1.7
BOTOCAN HEP				0.1			0.1		2.4	0.3	0.3	4.6
CALACA CFTPP	0.9			0.1			0.3		3.8	1.8	0.4	6.7
CALIRAYA HEP									0.3			1.5
CASECNAN HEP	2.4						0.4		2.7	0.7	0.1	4.3
CIP DPP	0.7	2.4	1.9	0.8	2.4	2.4	1.9	0.9		0.4		
HEDCOR HEP	5.4			0.1			0.1		2.4	0.6	0.1	4.6
ILIJAN NGPP	5.6	15.9	13.8	2.4	8.5	15.2	5.4	14.2	7.5	14.6	12.1	5.1

PSFI (%) by Billing Month - Luzon												
Generating Plant	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
ISABELA BIOETHANOL	0.4	3.0	5.8	8.1	4.9		4.0	0.4				1.8
KALAYAAN PSPP	3.9	2.4	2.8	1.3	0.7	1.2	0.8	0.4	1.3	2.6	3.5	5.6
LIMAY CCGT	0.3	0.8	1.8		1.8	5.2	3.6	0.9				0.3
MAGAT HEP	2.4	3.1	1.5	4.7	2.4	5.1	4.4	2.0	3.6	5.3	1.1	8.9
MAKBAN GPP	5.4			0.1			0.1	0.5	4.0	1.7	0.3	6.7
MARIVELES CFTPP	1.2		5.8	21.0	20.8	27.4	33.9	29.6	15.1	31.1	44.5	42.1
MASINLOC CFTPP	15.2	12.8	17.4	46.8	35.6	26.9	36.9	30.1	38.8	34.4	32.1	34.0
MASIWAY HEP	5.2			0.1			0.1					3.2
MILLENNIUM GTPP						0.4	0.8	0.3	0.1			
NAVOTAS DPP	7.7	16.7	11.6	8.5	5.0	9.5	10.8	9.8	6.0	11.3	15.1	7.2
PAGBILAO CFTPP	44.0	23.4	13.2	23.4	11.3	7.1	16.8	24.5	49.3	42.5	42.5	46.9
PANTABANGAN HEP	1.2			0.4			0.1					0.1
PETRON SFFP	0.3											0.4
QPPL CFTPP	8.6		4.8	1.7	1.9	0.9	1.0	2.8	5.6	4.7	3.4	7.6
SAN LORENZO NGPP	9.3	7.4	9.2	1.7	6.9	6.5	1.1	6.0	7.0	3.3	1.1	7.2
SAN ROQUE HEP	0.8	0.4	1.3				0.1	7.3	23.4	8.2	6.6	7.9
SLTEC CFTPP						0.1	0.4					
STA RITA NGPP	14.1	11.8	14.4	2.0	8.2	8.9	1.9	5.6	7.3	4.4	0.9	8.1
SUAL CFTPP	50.7	42.1	33.5	53.6	31.9	15.3	45.1	30.4	25.7	31.0	28.4	34.3
SUBIC DPP	1.9	6.6	6.8	3.5	4.4	7.7	3.2	6.6	0.5	0.8	5.5	1.8
TAPGC DPP	2.0	3.8	3.6	3.2	3.8	3.9	2.5	0.5	0.1	0.6	3.4	1.7
TIWI GPP	5.4			0.1			0.1		3.8	1.3	0.3	6.7

Table 59 PSFI by Billing Month - Luzon

PSFI (%) by Billing Month - Visayas												
Generating Plant	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
BOHOL DPP			0.1		0.3	0.5	0.3	0.3		0.6	1.3	
CEBU DPP I	0.4	2.2	2.2		2.5	3.1	2.6	0.9		0.7	0.3	
CEBU DPP II	0.4	1.7	1.6		2.5	3.1	3.1	0.9		0.7	0.3	
CEDC CFTPP	5.4	6.6	3.3	6.2	4.9	6.6	6.7	3.1	5.8	7.5	3.1	5.1
CPPC DPP	0.5	2.7	1.9	0.1	1.3	1.6	2.2	1.7	1.5	3.8	4.0	2.4
EAUC DPP	1.5	8.7	13.2	3.8	5.4	6.7	5.4	6.3	2.8	5.1	6.5	6.4
KSPC CFTPP	30.8	16.4	13.8	41.8	12.1	6.5	28.8	23.0	18.3	33.8	16.1	22.5
LEYTE A GPP	8.7	4.0	5.2	8.2	9.2	14.9	14.7	6.5	10.9	12.6	10.6	14.6
NABAS DPP	4.6	4.8	1.9	3.0	2.8	4.7	4.4	1.7	3.9	1.0	1.7	1.5
NASULO GPP	6.6	0.1		0.1			1.4		3.8	7.2	0.3	10.8
PALINPINON GPP I	8..5	0.4	0.4	0.4			1.8		2.7	7.5	0.3	10.3
PALINPINON II	1.6	0.1		0.7	0.4	1.1	0.6		2.6	6.7	0.4	11.0
PANAY DPP I								0.8	0.3		1.1	0.1
PANAY DPP III	0.9	2.3	1.9	0.7		0.8	1.1	1.1	0.5	0.4	3.5	0.6
PB 101	2.0											
PB 102	3.2											
PEDC CFTPP	18.7	9.8	12.2	22.7	14.4	13.0	14.2	11.4	13.4	21.7	23.4	16.7
TANGONAN GPP	7.3	0.1	0.1	0.1			0.3	0.7	3.4	7.6	0.4	10.4

PSFI (%) by Billing Month - Visayas												
Generating Plant	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
TPC (CARMEN) DPP	2.2	2.3	2.5	0.1	2.9	7.7	4.4	1.7		1.4	1.3	1.1
TPC (SANGI) CFTPP	14.4		18.2	14.4	15.4	14.2	14.4	11.4	6.0	1.5	0.3	

Table 60 PSFI by Billing Month - Visayas

PSFI (%) by Billing Month - Luzon (Above PhP5,000/MWh)												
Generating Plant	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
AMBUKLAO HEP	2.3	7.8	3.9	0.7		0.1					0.3	0.3
ANGAT HEP		0.9	5.8	2.4	1.3						3.4	2.5
BATANGAS DPP	0.4	4.2	0.6	0.7	1.0	0.7	1.0	0.1	0.4	0.7	0.5	0.8
BAUANG DPP	2.6	4.4	5.7	3.9	7.5	4.4	3.1	0.5	0.1	0.8	1.5	3.2
BINGA HEP	0.5				0.8							
CASECNAN HEP							0.3		0.3			0.1
CIP DPP	0.7	2.4	1.9		1.4	2.4	1.9	0.9		0.4		
ILIJAN NGPP									0.1			
ISABELA BIOETHANOL	0.4	2.4	0.4		0.6		0.8	0.4				1.8
KALAYAAN PSPP	1.5	2.4	2.8	1.3	0.7	1.2	0.8	0.4	1.1	2.4	3.5	0.7
LIMAY CCGT	0.3	0.8	1.8		1.8	5.2	3.6	0.9				0.3
MAGAT HEP	0.8	3.1	1.5	0.5	0.1	4.4	3.6	2.0	0.4	0.3	0.5	1.7
MASINLOC CFTPP						0.1						
MILLENNIUM GTPP						0.4	0.8	0.3	0.1			
NAVOTAS DPP	7.7	16.7	11.6	7.0	0.6	0.5						
SAN LORENZO NGPP			0.3			1.2						
SAN ROQUE HEP							0.1	0.1				
STA RITA NGPP			0.9			1.2						
SUAL CFTPP			0.1									
SUBIC DPP	1.9	6.2	6.3	1.7	0.8	0.8	1.0	0.4	0.1		2.2	1.8
TAPGC DPP	1.6	3.8	3.6	0.1	1.0	0.8	2.1	0.5	0.1	0.6	3.4	1.7

Table 61 PSFI by Billing Month - Luzon (Above PhP5,000/MWh)

PSFI (%) by Billing Month - Visayas (Above PhP5,000/MWh)												
Generating Plant	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
BOHOL DPP			0.1		0.3	0.5	0.3	0.3		0.6	1.3	
CEBU DPP I	0.4	2.2	2.2		2.5	3.1	2.6	0.9		0.7	0.3	
CEBU DPP II	0.4	1.7	1.6		2.5	3.1	3.1	0.9		0.7	0.3	
CPPC DPP	0.5	2.7	1.9	0.1	1.3	1.6	2.2	1.7	1.5	3.6	0.1	
EAUC DPP	1.5	6.0	8.2	2.0	3.3	5.4	2.8	2.8	0.8	3.2	4.2	3.2
LEYTE A GPP		0.4				0.4						
NABAS DPP	4.6	4.8	1.9	3.0	2.8	4.7	4.4	1.7	3.9	1.0	1.7	1.5
PANAY DPP I								0.8	0.3		1.1	0.1
PANAY DPP III	0.8	2.3	1.9	0.7		0.8	1.1	1.1	0.5		3.5	0.1
PB 101	2.0											
PB 102	3.2											

PSFI (%) by Billing Month - Visayas (Above PhP5,000/MWh)												
Generating Plant	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
PEDC CFTPP	3.6	3.9	4.2	6.7	5.4	2.8	2.6	2.2	2.2	1.7	2.4	0.7
TPC (CARMEN) DPP	2.2	2.3	2.5	0.1	2.9	7.7	4.4	1.7		1.4	1.3	1.0

Table 62 PSFI by Billing Month - Visayas (Above PhP5,000/MWh)

Likewise, frequent price setters at the above PhP10,000/MWh level were mostly oil-based plants, with Visayas plants Nabas and TPC (Carmen) occupying the top two spots, followed by Luzon plant Bauang, Visayas plants Cebu I and II and Luzon plant Limay. Hydro plants Magat and Kalayaan were also among the frequent price setters at this level.

The number of price-setters within the range of above PhP10,000/MWh notably increased in June, corresponding to the increase in the average market prices during the billing month.

The above PhP20,000/MWh price range was similarly dominated by oil-based plants, particularly from Luzon. These include Limat CCGT, Bauang, Navotas and Millenium. Visayas oil-based plant CPPC is also a frequent price setter within this range.

Note that the billing month of June recorded the highest number of frequent price-setters within the above PhP20,000/MWh price range.

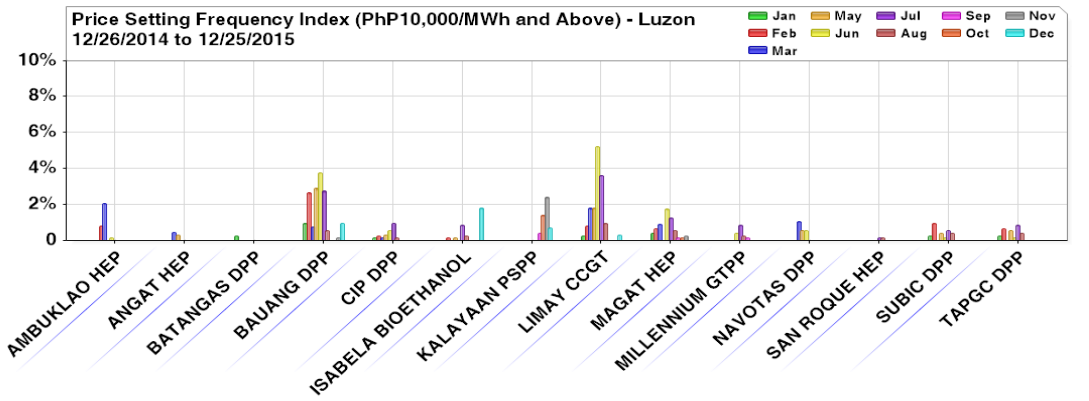

Figure 51 Price Setting Frequency Index - Luzon Plants (Above Php10,000/MWh)

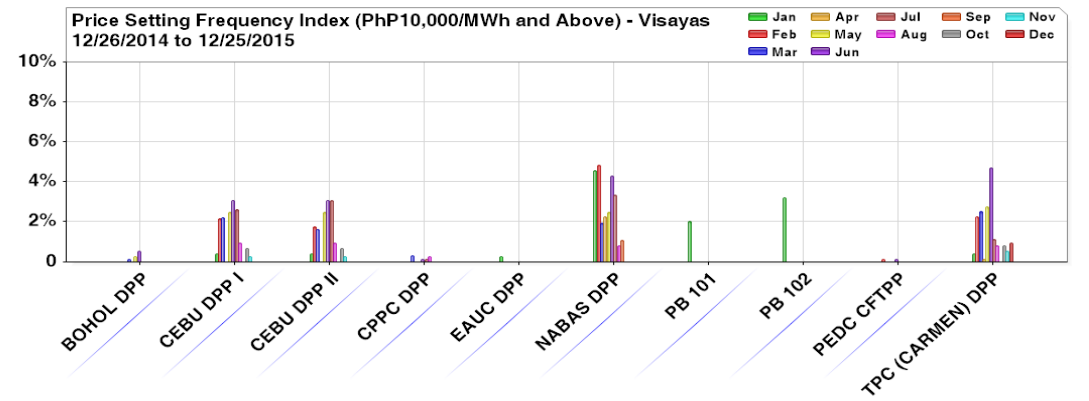

Figure 52 Price Setting Frequency Index - Luzon Plants (Above Php10,000/MWh)

PSFI (%) by Billing Month - Luzon (Above PhP10,000/MWh)												
Generating Plant	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
AMBUKLAO HEP		0.8	2.1			0.1						
ANGAT HEP			0.4		0.3							
BATANGAS DPP	0.3											
BAUANG DPP	0.9	2.7	0.7		2.9	3.8	2.8	0.5			0.1	1.0
CIP DPP	0.1	0.3	0.1		0.3	0.5	1.0	0.1				
ISABELA BIOETHANOL		0.1			0.1		0.8	0.3				1.8
KALAYAAN PSPP									0.4	1.4	2.4	0.7
LIMAY CCGT	0.3	0.8	1.8		1.8	5.2	3.6	0.9				0.3
MAGAT HEP	0.4	0.7	0.9			1.7	1.3	0.5	0.1	0.1	0.3	
MILLENNIUM GTPP						0.4	0.8	0.3	0.1			
NAVOTAS DPP			1.0		0.6	0.5						
SAN ROQUE HEP							0.1	0.1				
SUBIC DPP	0.3	0.9			0.4	0.1	0.6	0.4				
TAPGC DPP	0.3	0.7			0.6	0.1	0.8	0.4				

Table 63 PSFI by Billing Month - Luzon (Above PhP10,000/MWh)

PSFI (%) by Billing Month - Visayas (Above PhP10,000/MWh)												
Generating Plant	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
BOHOL DPP			0.1		0.3	0.5						
CEBU DPP I	0.4	2.2	2.2		2.5	3.1	2.6	0.9		0.7	0.3	
CEBU DPP II	0.4	1.7	1.6		2.5	3.1	3.1	0.9		0.7	0.3	
CPPC DPP			0.3			0.1	0.1	0.3				
EAUC DPP	0.3											
NABAS DPP	4.6	4.8	1.9	2.3	2.5	4.3	3.3	0.8	1.1			
PB 101	2.0											
PB 102	3.2											
PEDC CFTPP		0.1				0.1						
TPC (CARMEN) DPP	0.4	2.3	2.5	0.1	2.8	4.7	1.1	0.8		0.8	0.5	1.0

Table 64 PSFI by Billing Month - Visayas (Above PhP10,000/MWh)

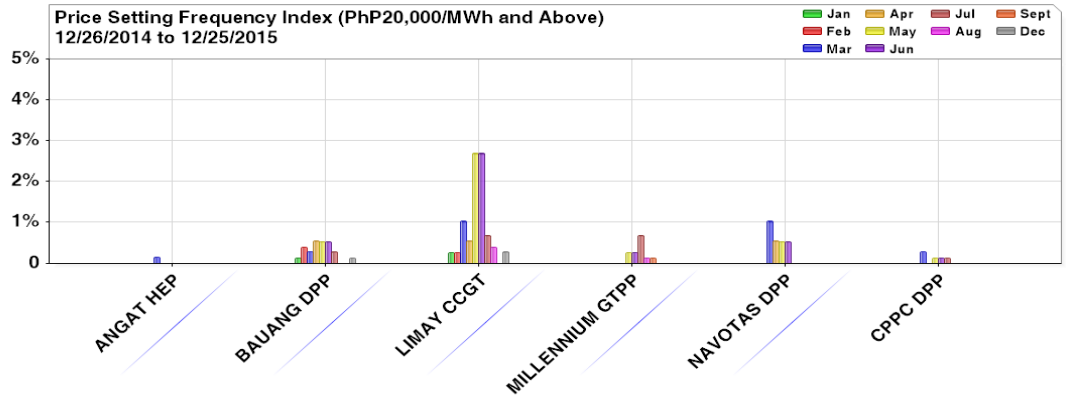

Figure 53 Price Setting Frequency Index (Above Php20,000/MWh)

PSFI (%) by Billing Month - Luzon (Above PhP20,000/MWh)												
Generating Plant	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
LUZON	0.2	0.3	0.6	0.6	1.0	1.0	0.6	0.3	0.1			0.2
ANGAT HEP			0.1									
BAUANG DPP	0.1	0.4	0.3	0.6	0.5	0.5	0.3					0.1
LIMAY CCGT	0.3	0.3	1.0	0.6	2.7	2.7	0.7	0.4				0.3
MILLENNIUM GTPP					0.3	0.3	0.7	0.1	0.1			
NAVOTAS DPP			1.0	0.6	0.5	0.5						
VISAYAS			0.3		0.1	0.1	0.1					
CPPC DPP			0.3		0.1	0.1	0.1					

Table 65 PSFI by Billing Month (Above PhP20,000/MWh)

PIVOTAL SUPPLIERS

PIVOTAL SUPPLY INDEX (PSI)

The Pivotal Supply Index (PSI) measures how critical a particular generator is in meeting the total demand at a particular time. It is a binary variable (1 for pivotal and 0 for not pivotal) which measures the frequency that a generating is pivotal for a particular period. A generator is considered pivotal if its capacity is needed to meet the demand requirements for a particular hour. The higher the demand requirement, or if a large plants is on outage, the higher the probability of generating plants qualifying as pivotal.

Pivotal Generators have greater opportunity to influence the market price by exercising their market power either through capacity withholding or offering prices above their usual price offers. Pivotal Generators can offer any price and because they are pivotal, their offered quantities will still be dispatched.

Major coal plant Sual topped the list of pivotal suppliers during the year, followed by natural gas plants Ilijan, coal plants Pagbilao, Masinloc, Calaca and Mariveles and natural gas plant San Lorenzo. It was observed that the frequency by which generators became pivotal rose significantly during the May and June billing months, which are the peak demand months, marked with tight supply and demand balance. On the contrary, manifesting the better supply and demand condition during the period, the September billing month posted the lowest number of pivotal suppliers, consistent with its low incidence of RMI level of less than 10 percent during the billing year.

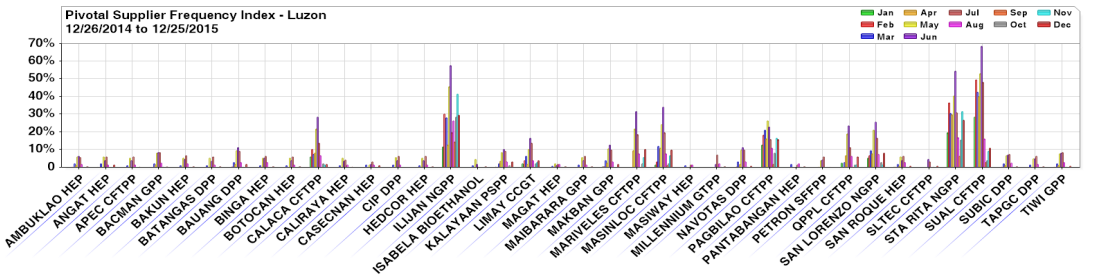

Figure 54 Pivotal Supplier Frequency Index - Luzon

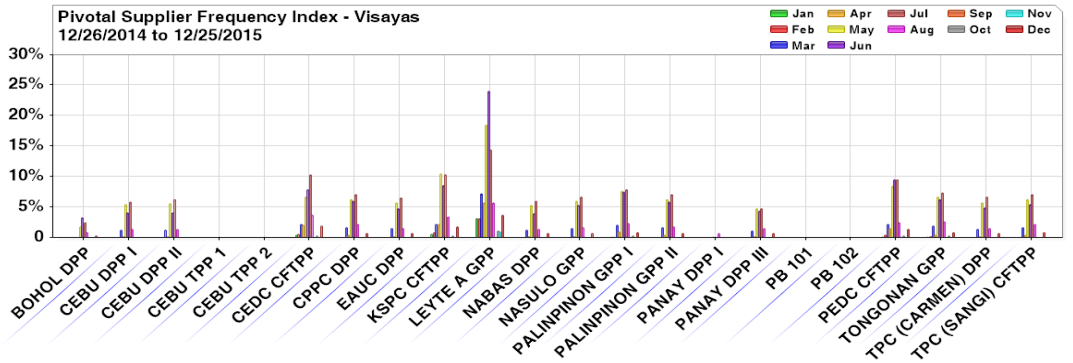

Figure 55 Pivotal Supplier Frequency Index - Visayas

Pivotal Supplier Index (%) by Billing Month, 2015												
Luzon Generating Plants	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
AMBUKLAO HEP	0.1	0.3	2.1	0.9	6.1	6.2	5.7	1.7	-	0.1	-	0.7
ANGAT HEP	0.1	0.1	2.2	0.4	6.0	3.9	6.0	1.3	-	0.1	-	1.3
APEC CFTPP	-	-	1.2	0.1	5.4	4.0	6.1	1.3	-	-	-	0.3
BACMAN GPP	0.1	0.1	2.2	1.3	7.9	8.3	8.5	2.6	-	0.3	-	0.6
BAKUN HEP	-	-	1.2	0.3	5.3	44	6.6	2.0	-	0.1	-	0.7
BATANGAS DPP	-	-	1.0	0.3	5.4	3.6	5.8	1.3	-	-	-	0.7
BAUANG DPP	0.4	0.5	2.7	1.7	9.6	11.2	9.2	2.7	-	0.3	-	1.7
BINGA HEP	-	-	1.2	0.3	5.4	5.4	6.4	2.7	-	0.1	-	0.7
BOTOCAN HEP			1.0	0.3	5.1	3.8	6.0	1.3	-	-	-	0.7
CALACA CFTPP	5.9	10.2	7.3	8.2	21.8	28.6	13.6	6.7	0.4	1.9	1.5	1.8
CALIRAYA HEP	-	-	1.0	0.3	5.3	3.6	4.2	1.5	-	0.1	-	0.3
CASECNAN HEP	-	-	1.3	0.1	1.5	1.7	3.1	1.3	-	0.1	-	1.0
CIP DPP	-	-	1.3	0.3	5.6	4.0	6.3	1.3	-	0.1		
HEDCOR HEP	-	-	1.2	0.3	5.3	4.0	6.3	1.5	-	-	-	0.7
ILIJAN NGPP	11.7	30.4	28.0	12.6	45.6	57.7	19.9	26.5	14.4	28.6	41.5	29.6
ISABELA BIOETHANOL	-	-	1.2	-	4.4	1.7	0.3	-			-	0.7
KALAYAAN PSPP	0.3	0.3	2.1	3.6	8.6	10.3	9.0	3.2	0.1	1.0	0.3	3.1
LIMAY CCGT	2.3	4.0	6.3	1.7	10.3	16.4	13.9	4.0	0.1	2.1	3.0	4.0
MAGAT HEP	-	0.1	0.7	0.1	2.2	1.2	1.7	1.7	-	0.3	-	0.7
MAIBARARA GPP	-	-	1.3	0.3	5.6	4.0	6.3	1.3	-	0.1	-	0.7
MAKBAN GPP	0.5	0.7	3.7	2.6	10.6	12.5	9.9	3.1	-	0.4	-	1.7
MARIVELES CFTPP	-		-	9.5	21.8	31.6	18.5	7.7	0.3	2.2	5.6	10.3
MASINLOC CFTPP	1.5	3.1	12.1	11.0	24.3	34.3	19.7	7.7	1.1	2.2	6.7	9.7
MASIWAY HEP	-	-	1.2	0.1	-		1.5	1.3				0.4
MILLENNIUM GTPP						1.9	7.1	2.3	-	0.3	-	0.7
NAVOTAS DPP	0.4	0.5	3.1	1.7	10.0	11.3	10.0	3.2	-	0.3	-	0.8
PAGBILAO CFTPP	12.6	18.3	21.3	16.3	26.4	22.7	16.0	10.9	1.9	8.2	16.4	15.7
PANTABANGAN HEP	-	0.1	1.9	-	-		1.4	2.0	-	0.3	-	0.7
PETRON SFFPP	-	-	-	0.3	4.0	4.2	6.1	-	-	0.1	-	0.1
QPPL CFTPP	2.6		3.0	6.7	19.0	23.5	11.4	6.5	0.3	1.5	1.3	5.8
SAN LORENZON NGPP	5.4	6.9	9.5	7.7	21.1	25.8	16.7	7.4	0.4	2.6	1.3	8.2
SAN ROQUE HEP	0.3	0.3	1.9	0.8	6.0	3.9	6.4	2.8	-	0.3	0.1	0.8
SLTEC CFTPP				-	-	4.7	3.1	0.3	-	0.3	-	0.8
STA RITA NGPP	19.6	36.4	30.7	29.8	40.4	54.4	31.1	16.8	6.3	15.6	31.7	26.7

Pivotal Supplier Index (%) by Billing Month, 2015												
Luzon Generating Plants	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
SUAL CFTPP	28.6	49.7	42.6	40.2	53.1	68.5	48.1	16.1	2.7	3.8	9.0	11.0
SUBIC DPP	-	0.3	2.1	0.9	6.7	7.1	7.2	2.6	-	-	-	0.7
TAPGC DPP	-	-	1.3	0.3	4.9	4.8	6.4	1.6	-	-	-	0.7
TAWI GPP	0.1	0.3	2.1	1.2	7.8	7.9	8.3	2.7	-	0.3	-	0.8

Table 66 Pivotal Supplier Frequency Index by Billing Month - Luzon

Pivotal Supplier Index (%) by Billing Month, 2015												
Visayas Generating Plants	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
BOHOL DPP		-	0.1		1.8	3.2	2.5	0.8	-	-	-	0.3
CEBU DPP I	-	-	1.2	0.3	5.4	4.0	5.8	1.3	-	-	-	-
CEBU DPP II	-	-	1.2	0.3	5.6	4.0	6.3	1.3	-	-	-	-
CEBU TPP 1												
CEBU TPP 2												
CEDC CFTPP	0.4	0.5	2.2	2.0	6.7	7.9	10.3	3.6	-	0.3	-	1.9
CPPC DPP	-	-	1.6	0.4	6.3	5.9	7.1	2.2	-	0.1	-	0.7
EAUC DPP	-	-	1.5	0.3	5.7	4.7	6.5	1.5	-	0.1	-	0.7
KSPC CFTPP	0.5	0.8	2.2	2.2	10.4	8.6	10.3	3.4	-	0.3	-	1.8
LEYTE A GPP	3.1	3.1	7.1	5.6	18.5	24.1	14.4	5.6	0.1	1.1	0.9	3.6
NABAS DPP	-	-	1.2	0.3	5.3	3.9	6.0	1.3	-	-	-	0.7
NASULO GPP	-	-	1.5	0.3	6.0	5.2	6.7	1.6	-	0.1	-	0.7
PALINPINON GPP I	0.1	0.1	2.1	0.9	7.6	7.5	7.9	2.3	-	0.3	-	0.8
PALINPINON GPP II	-	-	1.6	0.4	6.3	5.8	7.1	1.7	-	0.1	-	0.7
PANAY DPP I	-	-	-		-	0.1	-	0.7	-	-	-	-
PANAY DPP III	-	-	1.0	0.3	4.7	4.3	4.7	1.5	-	0.1	-	0.7
PB 101	-											
PB 102	-											
PEDC CFTPP	0.1	0.4	2.2	1.5	8.5	9.5	9.4	2.4	-	0.3	-	1.4
TONGONAN GPP	0.1	0.3	1.9	0.4	6.7	6.2	7.4	2.6	-	0.3	-	0.8
TPC (CARMEN) DPP	-	-	1.3	0.3	5.7	4.8	6.7	1.5	-	0.1	-	0.7
TPC (SANGI) CFTPP	-	-	1.6	0.4	6.3	5.4	7.1	2.2	-	0.1	-	0.8

Table 67 Pivotal Supplier Frequency Index by Billing Month - Visayas

PSI VS. PSFI

Shown in the table below is the list of pivotal generators that likewise qualified as price setters in the same trading interval, as well as the percent of time for a particular billing month that they became pivotal suppliers.

Across all prices, large generating coal plant Sual, natural gas plants Ilijan and Sta. Rita, and oil-based plants Bauang and Limay, coal plant Pagbilao, oil-based plants Navotas and Subic as well as hydro plant Kalayaan showed the most number of frequency of being pivotal and price-setter in the same trading interval from the Luzon region. On the other hand, from the Visayas, oil-based plants TPC (Carmen), Cebu I and 2, EAUC and CEDC were the top generators with the most frequency.

The May and June billing months marked the highest incidence of pivotal generators qualifying as price-setters at the same time, owing to the tight demand and supply balance during these months. Consistent with the resulting RMIs for the year, these months posted the highest occurrences of trading intervals marked with RMIs of less than 10 percent, indicating that the demand-supply balance was mostly tight in May and June. Correspondingly, the September billing month posted the lowest incidence, considering that in general, this month demonstrated better supply and demand condition when compared with the other billing months.

PSI vs. PSFI (%) by Billing Month (All Prices)												
Visayas Generating Plants	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
AMBUKLAO HEP	-	0.1	0.4	0.1	-	-	-	-	-	-	-	-
ANGAT HEP	-	-	-	-	0.4	-	-	-	-	-	-	-
BATANGAS DPP	-	-	-	-	0.4	-	0.1	-	-	-	-	-
BAUANG DPP	0.1	0.3	0.1	0.3	3.1	2.0	1.5	0.3	-	-	-	1.3
BOHOL DPP	-	-	-	-	0.3	03	-	0.1	-	-	-	-
CEBU DPP I	-	-	-	-	0.7	0.9	1.3	0.3	-	-	-	-
CEBU DPP II	-	-	-	-	0.7	0.9	1.3	0.3	-	-	-	-
CEDC CFTPP	-	-	-	-	-	0.5	1.1	-	-	-	-	-
CIP DPP	-	-	-	-	0.3	0.5	0.7	0.1	-	-	-	-
CPPC DPP	-	-	-	-	0.1	-	0.1	-	-	-	-	-
EAUC DPP	-	-	-	-	0.6	0.5	0.7	-	-	-	-	0.1
ILIJAN NGPP	0.1	-	0.7	0.8	4.7	6.5	0.6	3.4	1.4	7.1	8.3	2.9
ISABELA BIOETHANOL	-	-	-	-	-	-	-	-	-	-	-	0.1
KALAYAAN PSPP	-	-	-	0.9	0.4	0.1	-	-	-	0.3	-	0.6
KSPC CFTPP	-	-	-	0.9	-	-	-	-	-	-	-	0.1
LEYTE A GPP	-	-	-	-	-	0.9	0.3	-	-	-	-	0.4
LIMAY CCGT	0.3	0.8	1.8	-	1.7	3.8	2.8	0.9	-	-	-	0.3
MAGAT HEP	-	-	0.1	0.1	-	0.5	0.4	0.1	-	-	-	0.1
MARIVELES CFTPP	-	-	-	0.1	-	0.3	-	-	-	-	-	1.0
MASINLOC CFTPP	-	-	-	0.4	0.1	0.1	-	-	-	-	-	0.6
MILLENNIUM GTPP	-	-	-	-	-	-	0.3	0.1	-	-	-	-
NABAS DPP	-	-	-	-	0.3	0.1	0.4	-	-	-	-	0.1
NAVOTAS DPP	-	-	0.3	1.1	0.3	0.4	0.7	-	-	-	-	-
PAGBILAO CFTPP	0.4	0.3	0.4	0.3	0.3	-	-	-	-	-	-	1.8
PALINPINON GPP I	-	-	-	-	-	-	0.1	-	-	-	-	-
PANAY DPP III	-	-	-	-	-	0.1	-	-	-	-	-	-
PEDC CFTPP	-	-	-	0.3	0.7	0.5	0.1	-	-	-	-	-
SAN LORENZO NGPP	-	-	0.1	-	0.1	0.8	-	-	-	-	-	-
STA RITA NGPP	2.6	0.8	1.8	0.4	3.9	2.8	0.4	0.7	-	0.1	-	0.6
SUAL CFTPP	8.3	7.8	6.3	11.0	5.4	2.6	7.8	2.8	1.0	-	0.1	0.6
SUBIC DPP	-	0.3	0.3	0.1	0.4	0.7	0.6	-	-	-	-	-
TAPGC DPP	-	-	-	0.1	0.7	-	0.7	-	-	-	-	0.1
TPC (CARMEN) DPP	-	-	-	-	1.1	0.9	1.4	0.4	-	0.1	-	-
TPC (SANGI) CFTPP	-	-	-	-	0.1	0.9	0.3	-	-	-	-	-

Table 68 PSI vs. PSFI

Oil-based plants dominated the list of pivotal suppliers which were also the price setters at the above PhP5,000/MWh range as well as in the above PhP10,000/MWh range. The frequency by which the higher-priced plants became pivotal and price-setters at the same time were

observed mostly during the May to June billing months, when tight demand was supplied by the higher-priced oil-based plants in the market.

Oil-based plants Limay, Bauang, TPC (Carmen) and Cebu 1 and 2 emerged as the generators which most frequently set the price above PhP5,000/MWh and were pivotal suppliers at the same time. Natural gas plant Sta. Rita also figured on top together with hydro plants Kalayaan and Magat. For prices above PhP10,000/MWh, the most frequent price setters which were also pivotal were also oil-based plants Limay, Bauang, Cebu 1 and 2, TPC (Carmen), and CIP, followed by hydro plants Kalayaan and Magat.

PSI vs. PSFI (%) by Billing Month (Above PhP 5,000/MWh)											
Generating Plants	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Dec
AMBUKLAO HEP	-	0.1	0.4	-	-	-	-	-	-	-	-
ANGAT HEP	-	-	-	-	0.4	-	-	-	-	-	-
BATANGAS DPP	-	-	-	-	0.4	-	0.1	-	-	-	-
BAUANG DPP	0.1	0.3	0.1	0.3	3.1	2.0	1.5	0.3	-	-	1.3
BOHOL DPP	-	-	-	-	0.3	0.3	-	0.1	-	-	-
CEBU DPP I	-	-	-	-	0.7	0.9	1.3	0.3	-	-	-
CEBU DPP II	-	-	-	-	0.7	0.9	1.3	0.3	-	-	-
CIP DPP	-	-	-	-	0.3	0.5	0.7	0.1	-	-	-
CPPC DPP	-	-	-	-	0.1	-	0.1	-	-	-	-
EAUC DPP	-	-	-	-	0.6	0.5	0.7	-	-	-	0.1
ILIJAN NGPP	-	-	-	-	-	-	-	-	0.1	-	-
ISABELA BIOETHANOL	-	-	-	-	-	-	-	-	-	-	0.1
KALAYAAN PSPP	-	-	-	0.9	0.4	0.1	-	-	-	0.3	0.4
KSPC CFTPP	-	-	-	0.3	-	-	-	-	-	-	-
LIMAY CCGT	0.3	0.8	1.8	-	1.7	3.8	2.8	0.9	-	-	0.3
MAGAT HEP	-	-	0.1	-	-	0.5	0.4	0.1	-	-	0.1
MILLENNIUM GTPP	-	-	-	-	-	-	0.3	0.1	-	-	-
NABAS DPP	-	-	-	-	0.3	0.1	0.4	-	-	-	0.1
NAVOTAS DPP	-	-	0.3	1.1	0.3	-	-	-	-	-	-
PANAY DPP III	-	-	-	-	-	0.1	-	-	-	-	-
PEDC CFTPP	-	-	-	0.3	0.7	0.5	0.1	-	-	-	-
SAN LORENZO NGPP	-	-	0.1	-	-	0.8	-	-	-	-	-
STA RITA NGPP	-	-	0.9	-	0.3	1.2	-	-	-	-	-
SUAL CFTPP	-	-	0.1	-	-	-	-	-	-	-	-
SUBIC DPP	-	0.3	0.3	-	0.3	0.3	0.1	-	-	-	-
TAPGC DPP	-	-	-	0.1	0.7	-	0.4	-	-	-	0.1
TPC (CARMEN) DPP	-	-	-	-	1.1	0.9	1.4	0.4	-	0.1	-

Table 69 PSI vs. PSFI (Above PhP5,000/MWh)

PSI vs. PSFI (%) by Billing Month (Above PhP 10,000/MWh)									
Generating Plants	Jan	Feb	Mar	May	Jun	Jul	Aug	Oct	Dec
AMBUKLAO HEP	-	0.1	-	-	-	-	-	-	-
ANGAT HEP	-	-	-	0.3	-	-	-	-	-
BAUANG DPP	0.1	0.3	0.1	1.7	1.5	1.4	0.3	-	0.4
BOHOL DPP	-	-	-	0.3	0.3	-	-	-	-
CEBU DPP I	-	-	-	0.7	0.9	1.3	0.3	-	-

PSI vs. PSFI (%) by Billing Month (Above PhP 10,000/MWh)									
Generating Plants	Jan	Feb	Mar	May	Jun	Jul	Aug	Oct	Dec
CEBU DPP II	-	-	-	0.7	0.9	1.3	0.3	-	-
CIP DPP	-	-	-	0.1	0.1	0.4	0.1	-	-
CPPC DPP	-	-	-	-	-	0.1	-	-	-
ISABELA BIOETHANOL	-	-	-	-	-	-	-	-	0.1
KALAYAAN PSPP	-	-	-	-	-	-	-	0.3	0.4
LIMAY CCGT	0.3	0.8	1.8	1.7	3.8	2.8	0.9	-	0.3
MAGAT HEP	-	-	0.1	-	0.3	0.3	-	-	-
MILLENNIUM GTPP	-	-	-	-	-	0.3	0.1	-	-
NABAS DPP	-	-	-	0.3	-	0.4	-	-	-
NAVOTAS DPP	-	-	0.3	0.3	-	-	-	-	-
SUBIC DPP	-	0.1	-	0.1	-	0.1	-	-	-
TAPGC DPP	-	-	-	0.3	-	0.3	-	-	-
TPC (CARMEN) DPP	-	-	-	1.0	0.8	0.3	0.3	-	-

Table 70 PSI vs. PSFI (Above PhP10,000/MWh)

RESIDUAL SUPPLY INDEX (RSI)

The Residual Supply Index (RSI) measures the ratio of available supply without a generator to the total supply required to meet the demand. The RSI of a generator measures the percentage of the remaining available supply in the market after subtracting the available capacity of that generator. The market RSI is measured as the lowest RSI among all generators in the market. A market RSI less than 100 percent indicates the presence of pivotal generator/s or supplier/s.

As already discussed, following the tight demand and supply conditions in May and June, the presence of pivotal suppliers manifested in majority of the trading intervals during these months, indicated by the number of times the market RSI fell below the 100 percent mark (53.1 percent in May and 68.8 percent in June). The rest of the billing months manifested improved supply conditions, with the market RSI exceeding 100 percent most of the time, indicating the absence of pivotal suppliers.

Year-on-year comparison showed that RSI levels are generally better this year than last year when the market RSI above 100 percent averaged at 52.7 percent, lower by about 7 percent from this year's 59.8 percent.

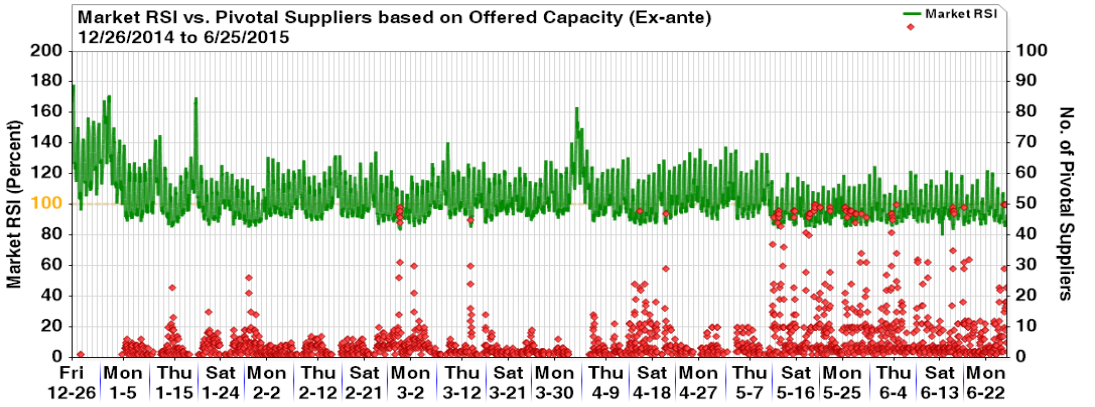

Figure 56 RSI Based on Offered Capacity - 1st Half

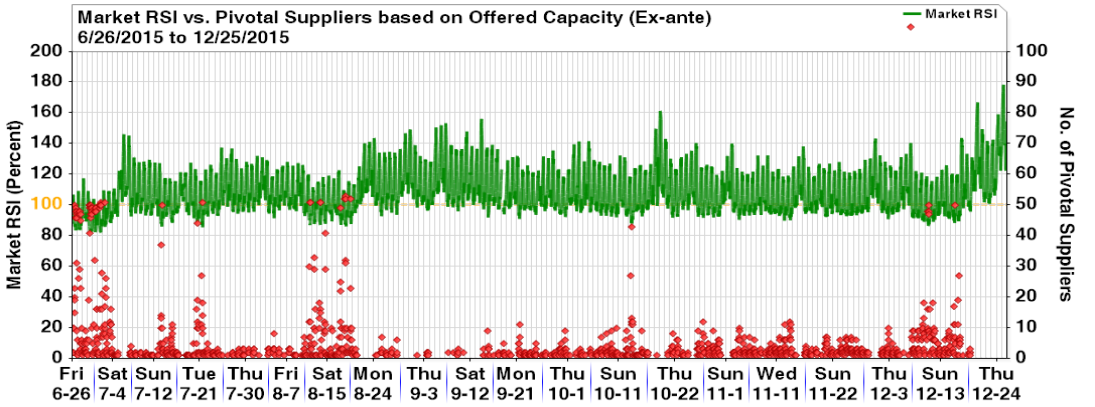

Figure 57 RSI Based on Offered Capacity - 2nd Half

	Market RSI (%) Distribution by Billing Month - 2015						
	Jan	Feb	Mar	Apr	May	Jun	Jul
More than or equal to 100%	71.3	50.1	52.8	59.8	46.9	31.2	51.9
Less than 100%	28.7	49.9	47.2	40.2	53.1	68.8	48.1
continuation...	Aug	Sep	Oct	Nov	Dec	Annual Avg	
More than or equal to 100%	70.3	85.1	71.3	58.5	68.0	59.8	
Less than 100%	29.7	14.7	28.8	41.5	32.0	40.2	

Table 71 Market RSI Summary - 2015

	Market RSI (%) Distribution by Billing Month - 2014						
	Jan	Feb	Mar	Apr	May	Jun	Jul
More than or equal to 100%	71.6	63.7	35.0	39.0	39.4	31.7	17.1
Less than 100%	28.4	36.3	65.0	61.0	60.6	68.3	82.9

	Market RSI (%) Distribution by Billing Month - 2014					
continuation...	Aug	Sep	Oct	Nov	Dec	Annual Avg
More than or equal to 100%	52.6	65.3	69.4	66.7	78.7	52.7
Less than 100%	47.4	34.7	30.6	33.3	21.3	47.3

Table 72 Market RSI Summary - 2014

GENERATOR OFFER PATTERN

The generator offer index aims to determine trends or strategy in the offer behavior of generating plants according to resource type.

Throughout the billing year, Luzon geothermal plants exhibited the lowest offer prices among all resource types, with all of its offers priced at PhP0/MWh and below. During the period 12 to 19 February, higher RTD schedule than offered capacity was observed, attributable to the MRU designation of Bacman 1, during the course of its commissioning tests following its maintenance outage from 28 December 2014 to 12 February 2015.

Looking at the chart below, it is observed that capacity offers of geothermal plants in Luzon decreased on 14-18 December attributable to the forced outages of Bacman 1, 2, and 3 related to the onslaught of Typhoon Nona.

Given the lower offer prices from Luzon geothermal plants, an average of 99.7 percent of their capacity offers for the year were scheduled for dispatch.

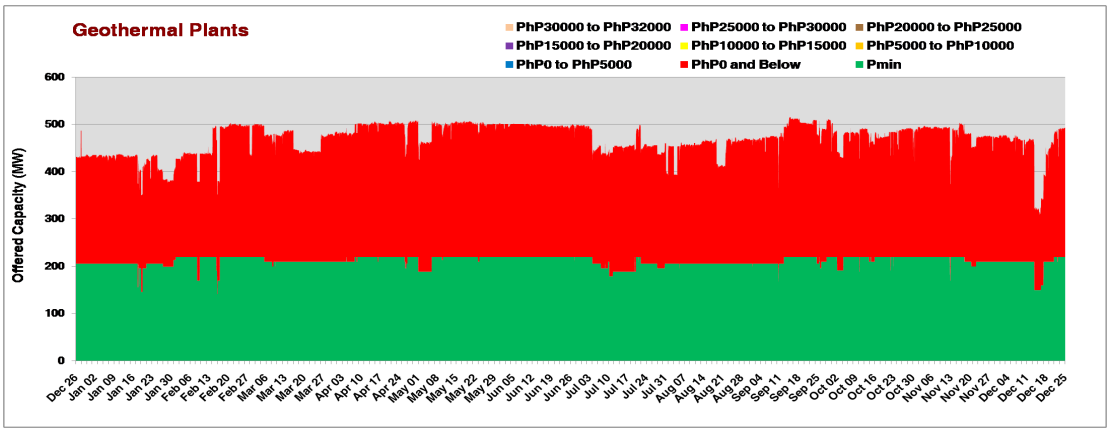

Figure 58 Geothermal Plants Offer Pattern - Luzon

On the other hand, Visayas geothermal plants had 76.9 percent of its offer prices at PhP0/MWh and below, while the remaining 23 percent is priced between PhP0/MWh to PhP5,000/MWh.

Dip in the offered capacity of Visayas geothermal plants was observed on 31 October to 01 November due to the emergency repair of the isolating valves of plant Malitbog units 1, 2 and 3 on top of the existing outages of geothermal plants Upper Mahiao 1 and PGPP1 Unit 2 during said period.

Meanwhile, higher RTD schedule than offered capacity was observed among the geothermal plants in the Visayas on 01 to 02 November due to the security limit imposed on Leyte A and Palinpinon 1 during said intervals.

About 99.2 percent of the offers of geothermal plants were scheduled for dispatch.

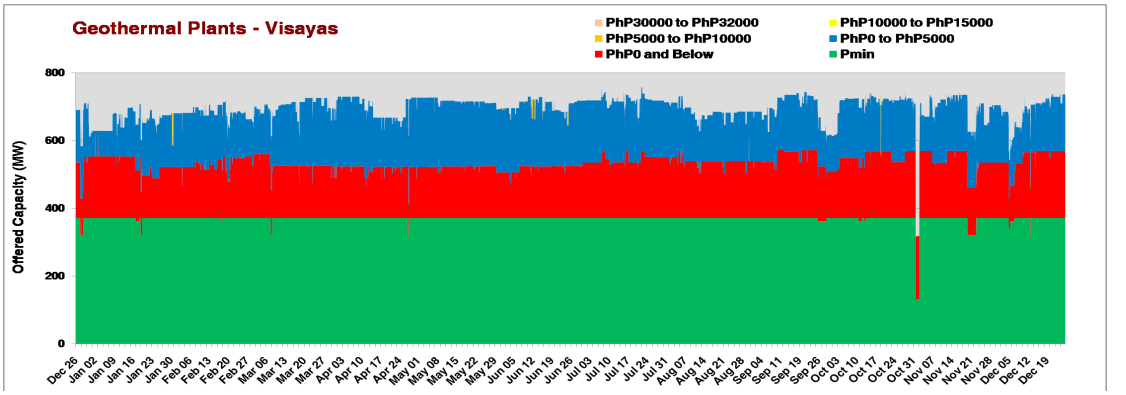

Figure 59 Geothermal Plants Offer Pattern - Visayas

About 57.5 percent of the capacity offers of Luzon coal plants during the year was priced at PhP0/MWh and below. About 40.5 percent of its offers had prices ranging above PhP0/MWh to PhP5,000/MWh while the remaining 1 percent, 0.7 percent and 0.3 percent were apportioned to prices ranging between above PhP5,000/MWh to PhP10,000/MWh, above PhP10,000/MWh to PhP20,000/MWh, and above PhP20,000/MWh, respectively.

As illustrated in Figure 59, offered capacity of Luzon coal plants was relatively low during the first quarter of the year, attributed to the high outage capacity among coal plants in the region during said period. Capacity offers begun to increase during the March billing month as more coal plants on outage resumed their operations. Also in March, higher RTD schedule than the offered capacity was observed particularly on 15 to17 and 23 to 25 March when GN Power 1 and 2, Masinloc 1 and 2, and Calaca 2 were imposed with security limits for their start-up profile and conduct of various tests.

About 90 percent of the capacity offers of Luzon coal plants were scheduled for dispatch during the billing year.

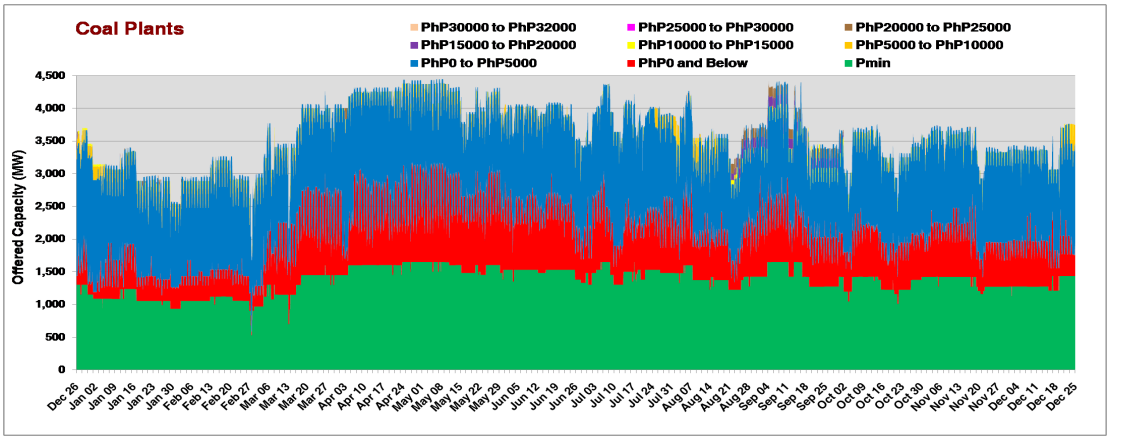

Figure 60 Coal Plants Offer Pattern - Luzon

Similarly, Visayas coal plants recorded relatively lower offer prices during the year, with about 77.3 percent of its offers priced at PhP0/MWh and below. Meanwhile, about 22 percent were offers priced between above PhP0/MWh to PhP5,000/MWh; about 0.4 percent between above PhP5,000/MWh to PhP10,000/MWh; while the remaining 0.3 percent were offer prices between above PhP30,000/MWh to PhP32,000/MWh.
Noticeable drop in the offered capacity of the coal plants in the Visayas were observed during the February billing month on account of the high outage capacity among the Visayas coal plants. In particular, KSPC 1 and 2 and PEDC 1 went on planned and forced outages, respectively, which drove the increase in the average outage capacity among the region's coal plants during this month.

About 90.8 percent of the capacity offers of Visayas coal plants were scheduled for dispatch this year.

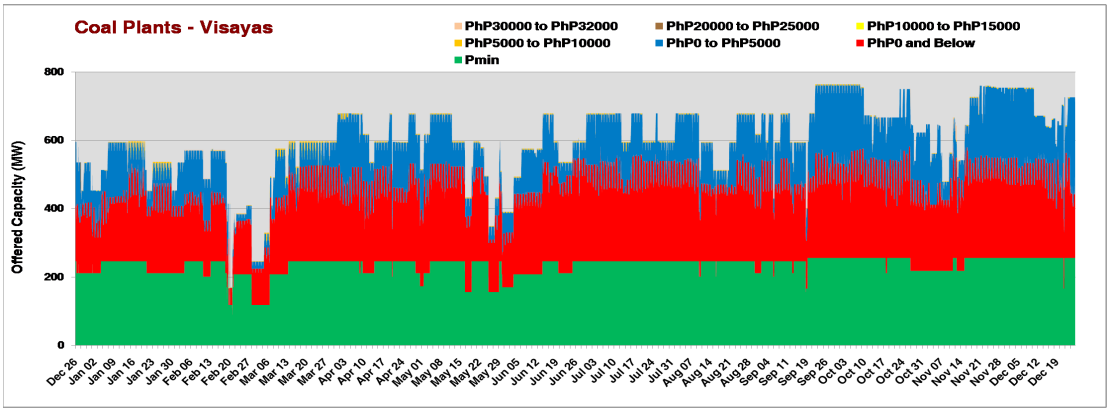

Figure 61 Coal Plants Offer Pattern - Visayas

Oil-based plants remained to be the most expensive source of power in the market among all plant types in 2015, as demonstrated by its high offer prices.

In Luzon, majority or 60.1 percent of its capacity offers were priced above PhP20,000/MWh, 9.0 percent of which were offer prices between above PhP30,000/MWh to PhP32,000/MWh. About 13.4 percent were apportioned to prices between above PhP10,000/MWh to PhP20,000/MWh; the next 10.1 percent were offer prices between above PhP5,000/MWh to PhP10,000/MWh while 16.4 percent were offer prices below PhP5,000/MWh.

As shown in Figure 61, noticeable change in the offer behavior of oil-based plants in Luzon manifested particularly during the second half of the year. Decrease in the offers comprising of about 37 percent which were typically priced between above PhP25,000/MWh to PhP30,000/MWh in the first semester, were priced lower in the second semester, ranging between above PhP20,000/MWh to PhP25,000/MWh. In addition, about 20 percent of the capacity offers which were priced between above PhP5,000/MWh to PhP10,000/MWh during the first semester of the year were shifted to prices below PhP5,000/MWh until yearend.

It is noteworthy that only an average of about 10.1 percent of the capacity offers of oil-based plants in Luzon were scheduled for dispatch during the billing year. Nevertheless, higher RTD schedule among oil-based plants were observed during the billing months of March, May, June and July posted at 14.5 percent, 18.5 percent, 27.9 percent and 17.1 percent, respectively, when market prices were also relatively high.

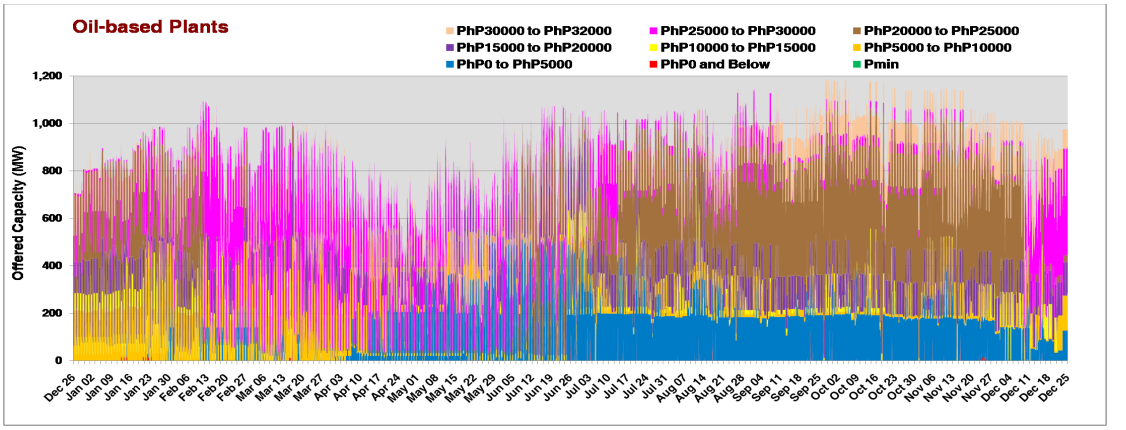

Figure 62 Oil-based Plants Offer Pattern - Luzon

Visayas oil-based plants were likewise priced higher than other resource types. In 2015, about 8.5 percent of its capacity offers were priced above PhP20,000/MWh while about 31.2 percent were apportioned to prices between above PhP10,000/MWh to PhP20,000/MWh. On the other hand, 34.4 percent were capacity offers priced between above PhP5,000/MWh to PhP10,000/MWh while the remaining 25.9 percent were prices below PhP5,000/MWh.

Shift in the offer prices of Visayas oil-based plants were observed during the last quarter of the year, with more capacity offers apportioned to prices between above PhP0/MWh to PhP5,000/MWh, as well as to prices between above PhP5,000/MWh to PhP10,000/MWh. About 20 percent of these capacity offers were noted to be apportioned to prices between above PhP10,000/MWh to PhP20,000/MWh during the first semester of the year. This change indicated that offer prices among Visayas oil-based plants were relatively lower in the last few months of the billing year.

Dispatch of the capacity offers of Visayas oil-based plants were observed to range between 11.7 percent in January to as high as 41.7 percent in June, with the exception of the September billing month which recorded an RTD schedule of only 8.3 percent among the Visayas oil-based plants. Over-all, an average of about 21.5 percent of the total offered capacity of oil-based plants in the Visayas were scheduled for dispatch during the year.

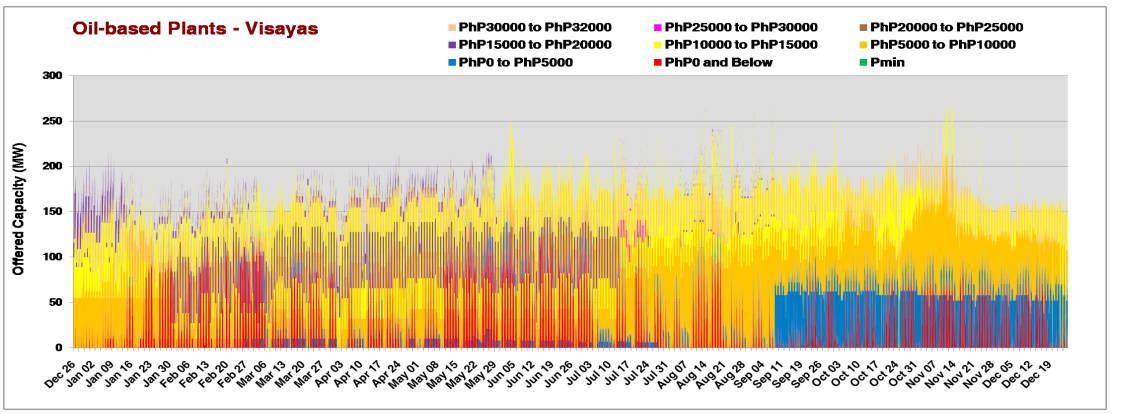

Figure 63 Oil-based Plants Offer Pattern - Visayas

Hydro plants exhibited volatility throughout the billing year in terms of both capacity offers and prices. Majority or about 62.8 of offers from hydro plants this year were priced at below PhP0/MWh; 14.1 percent, between above PhP0/MWh to PhP5,000/MWh; 17.1 percent were offer prices between above PhP5,000/MWh to PhP10,000/MWh; 5 percent were apportioned to prices between above PhP10,000/MWh to PhP20,000/MWh while the remaining 0.9 percent were priced above PhP20,000/MWh.

Capacity offers from hydro plants declined during the summer months of May and June, as shown in the chart below. On the other hand, rise in the capacity offers of hydro plants were observed during the second half of the billing year, with a corresponding decline in its offer prices, demonstrated by the increase in the offer prices between above PhP0/MWh and below. Accordingly, higher dispatch was observed among hydro plants during these months averaging at about 84 percent of the total capacity offers, except the December billing month with only 62.8 percent. Low RTD schedule was likewise observed particularly during the April billing month at 55.2 percent. Notwithstanding, dispatch of hydro plants for 2015 averaged at 76.3 percent.

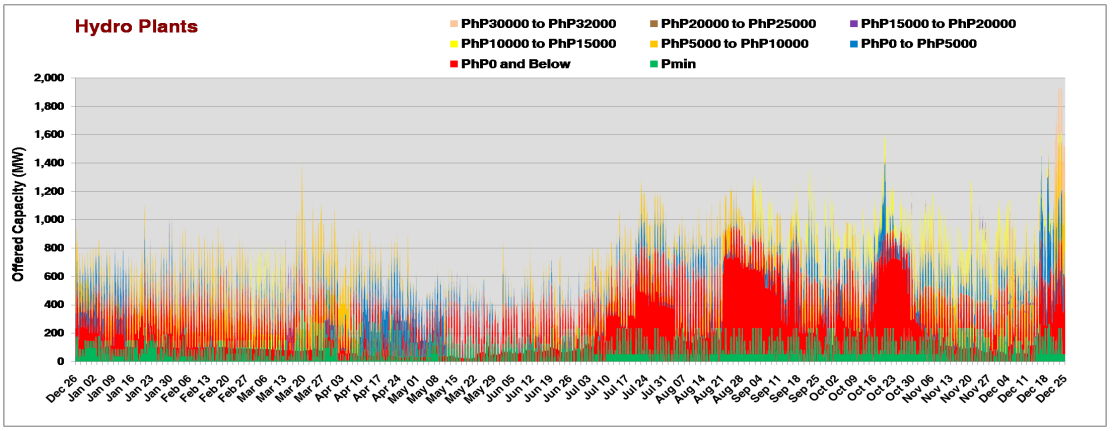

Figure 64 Hydro Plants Offer Pattern - Luzon

Offer prices of natural gas plants remained relatively lower when compared to other resource types. For the billing year, bulk or 83.9 percent of the capacity offers of natural gas plants were priced at PhP0/below. The remaining 14.8 percent were offers priced between above PhP5,000/MWh to PhP10,000/MWh while about 1.2 percent were offer prices between above PhP5,000/MWh to PhP10,000/MWh.

About 86.5 percent of the capacity offers of natural gas plants were scheduled for dispatch during the billing year.

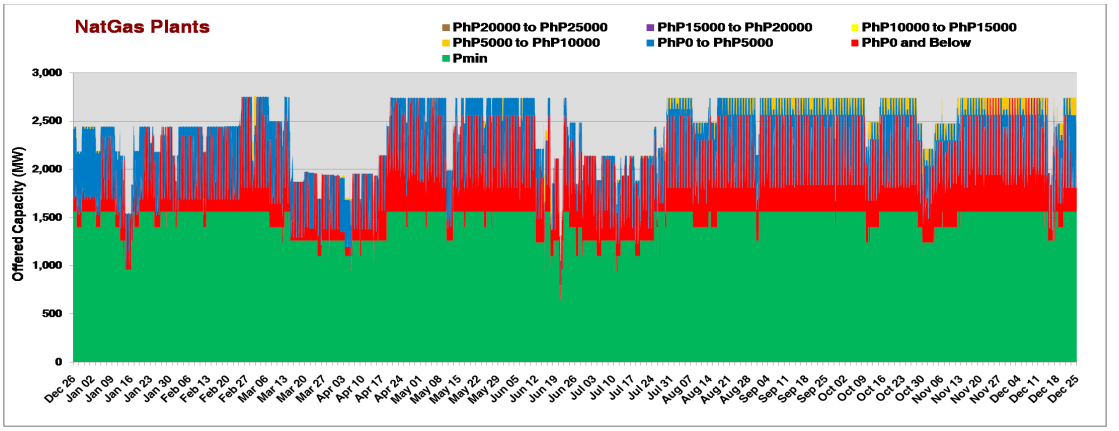

Figure 65 Natural Gas Plants Offer Pattern - Luzon

GENERATOR CAPACITY FACTOR

The capacity factor is calculated as the ratio of the metered quantity (actual generation) in the market of each of the plant type relative to the registered maximum capacity, registered less outage capacity, and maximum offered capacity. As shown in the Figures below, the monthly capacity factor of generation facilities show that the same varies depending on the energy resource type.

Natural gas plants remained consistent in logging high capacity factors throughout the billing year, averaging at 75.3 percent in terms of utilization based on registered capacity, the highest among all plant types; 81.9 percent based on registered less outage capacity, likewise the highest capacity factor among all plant types; and 86 percent capacity factor based on offered capacity. Natural gas plants recorded its highest utilization in June and July based on offered capacity, averaging at 90.4 percent and 90.2 percent respectively, suggesting that offers submitted by natural gas plants were mostly dispatched during these months. The overall utilization of natural gas plants throughout the year indicates that it had fewer occurrences of outages and had the least capacity gap among the plant types.

Luzon coal plants also obtained relatively higher capacity factors for the billing year, posting an average of about 61 percent utilization based on registered capacity, 72.6 percent in terms of registered less outage capacity and 84.9 percent in terms of offered capacity. Note that coal plants registered its lowest capacity factors based on registered capacity in January and February following its high outage capacity in these months.

Geothermal plants in Luzon incurred a 48.9 percent utilization based on registered capacity and a capacity factor of 72.3 percent based on registered less outage capacity, suggesting the high outage level among geothermal plants. However, based on offered capacity, geothermal plants posted a 92.7 percent capacity factor, an indication that offers submitted by geothermal plants were generally dispatched and utilized.

Hydro plants demonstrated low utilization throughout the year based on registered capacity and registered less outage capacity, averaging at 21.4 percent and 23.3 percent, respectively, for year 2015. This pattern of low utilization is consistent with the limited submission of offers as reflected in the high level of capacity gap among hydro plants. Nevertheless, hydro plants

posted an average of 92.4 percent capacity factor based on offered capacity, indicating that capacity offers of hydro plants are generally dispatched and utilized in the market. Note however, that from June to August, the actual generation of hydro plants exceeded its offered capacity, in part attributed to the increase in the imposition of security limits on hydro plants during these months.

Meanwhile, oil-based plants recorded the lowest utilization among all plant types, plunging to a mere 5.8 percent and 7.2 percent, respectively, based on registered capacity and registered less outage capacity. Low capacity factor was likewise posted among oil-based plants when actual generation is compared with offered capacity, posting an annual average of only 14.1 percent. Nonetheless, higher levels of capacity factors based on offered capacity is posted in May, June and July at 29.3 percent, 34.9 percent and 21.3 percent, indicating the more frequent dispatch and higher utilization of oil-based plants following the tight demand and supply condition during these months.

On the other hand, the capacity factors of preferential dispatch generating units on a monthly basis, showed the effects of seasonal changes on their capability to generate power.

The utilization of Luzon solar plants was relatively higher during the summer months of April to June. However, with the onset of the rainy season starting the July billing month, the capacity factor of solar plants decreased, from an average of 21.5 percent in June to 18.1 percent in July. The highest capacity factor of solar plants was posted in April at 24.3 percent. On the other hand, significant increase in the capacity factor of wind plants was demonstrated during the last quarter of the billing year, while utilization was low during the summer months of May and June, averaging at only 8 percent and 4.8 percent, respectively.

Biomass plants in Luzon likewise manifested a seasonal increase/decrease in its actual generation of power. Capacity factor of biomass plants followed an increasing trend this year, reaching a high of 62.9 percent in December from a low of 2.1 percent in June.

In the Visayas, geothermal plants obtained the highest capacity factors among all plant types in the region. Based on registered capacity, Visayas geothermal plants posted a 74.6 percent utilization; based on registered less outage capacity, 80.2 percent; and based on offered capacity vis-a-vis actual generation, 94.8 percent.

On the other hand, coal plants in the Visayas posted a 58.5 percent capacity factor this year in terms of registered capacity, 66.5 percent in terms of registered less outage capacity and 72.4 percent capacity factor in terms of offered capacity. Note that utilization of coal plants was lowest in March, in time when outage capacity and capacity not offered were noted to be relatively high. In contrast, Visayas coal plants registered high utilization in June when demand and supply was mostly tight, demonstrating that coal plants had less outages and less capacity gap and further, that its offers were dispatched more frequently during this month.

Similar to the trend in Luzon, wind plants in the Visayas recorded low capacity factors during the summer months of May and June, and had high utilization levels during the first and last quarters of the year. On the other hand, solar plants showed consistency in its capacity factors ranging from a low of 15.5 percent to 24.4 percent. Finally, biomass plants posted consistently low capacity factors from May to August, ranging from only 0.9 percent to 1 percent. However, consistent utilization levels across all other months were observed among Visayas biomass plants, with capacity factors ranging between 15.7 percent in January to 35.6 percent in November.

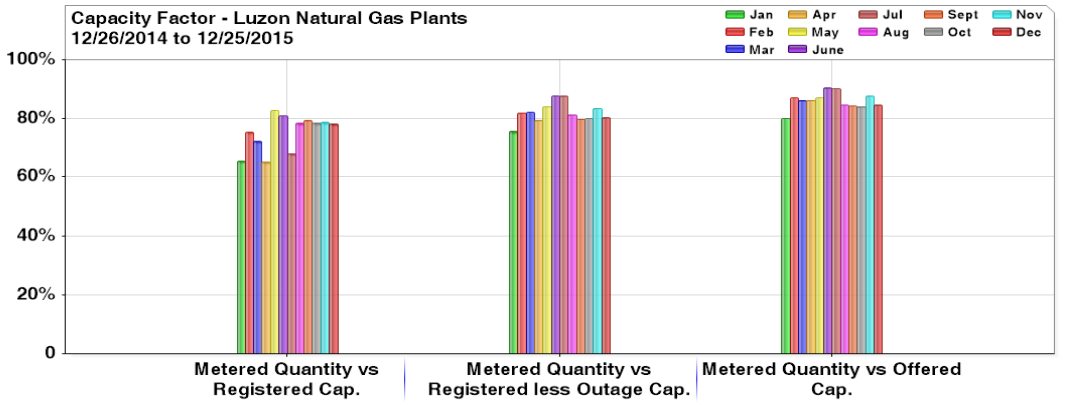

Figure 66 Capacity Factor - Luzon Natural Gas Plants

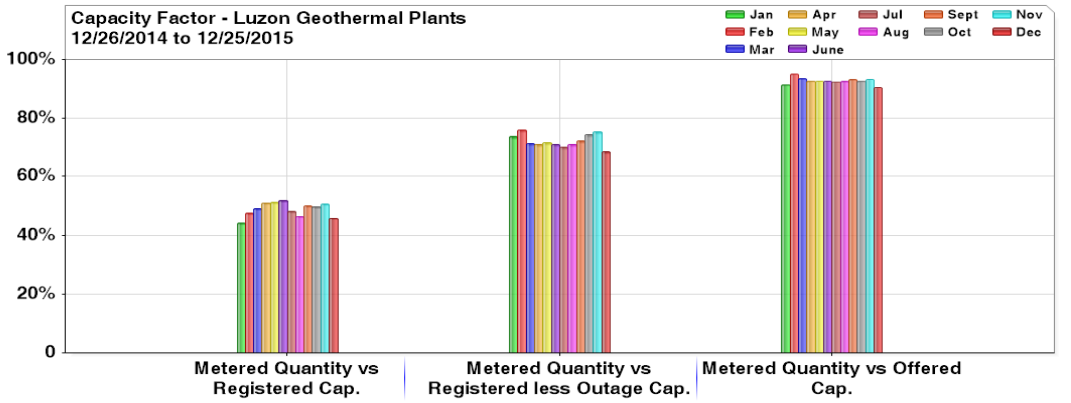

Figure 67 Capacity Factor - Luzon Geothermal Plants

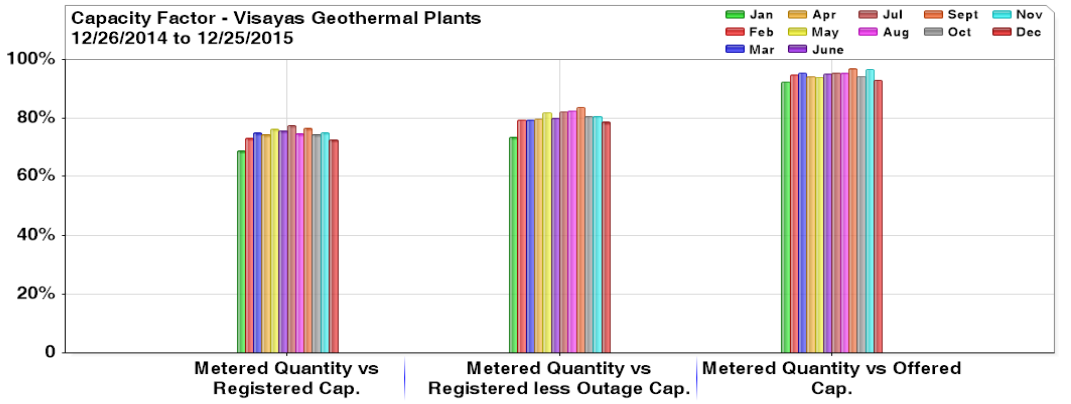

Figure 68 Capacity Factor - Visayas Geothermal Plants

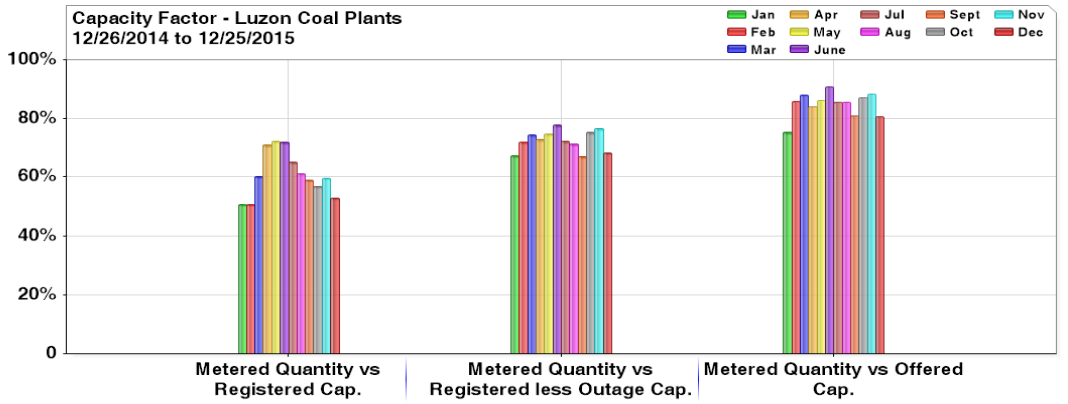

Figure 69 Capacity Factor - Luzon Coal Plants

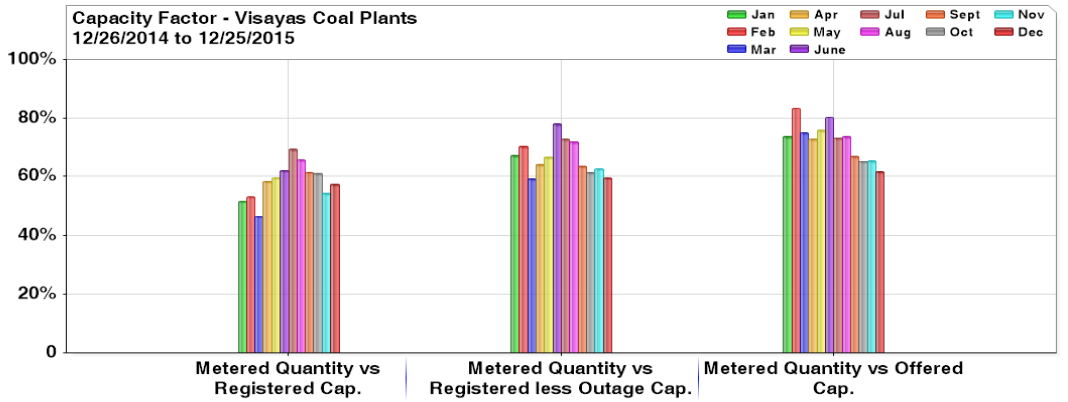

Figure 70 Capacity Factor - Visayas Coal Plants

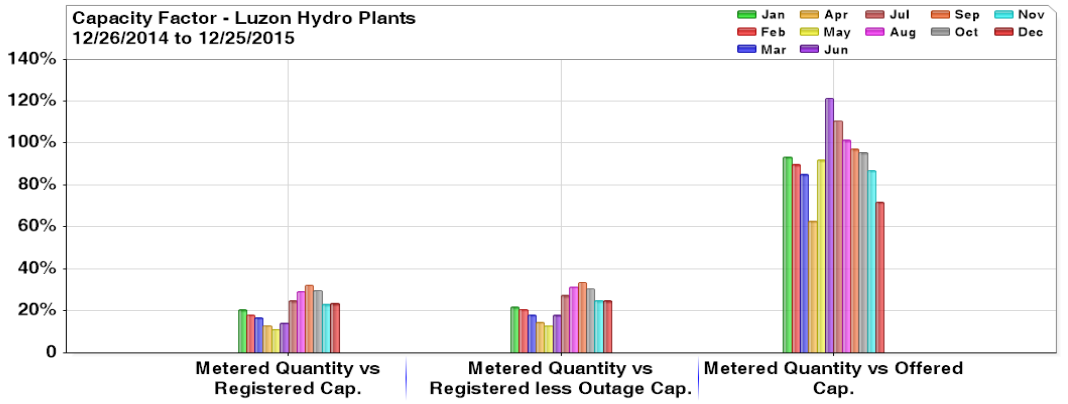

Figure 71 Capacity Factor - Luzon Hydro Plants

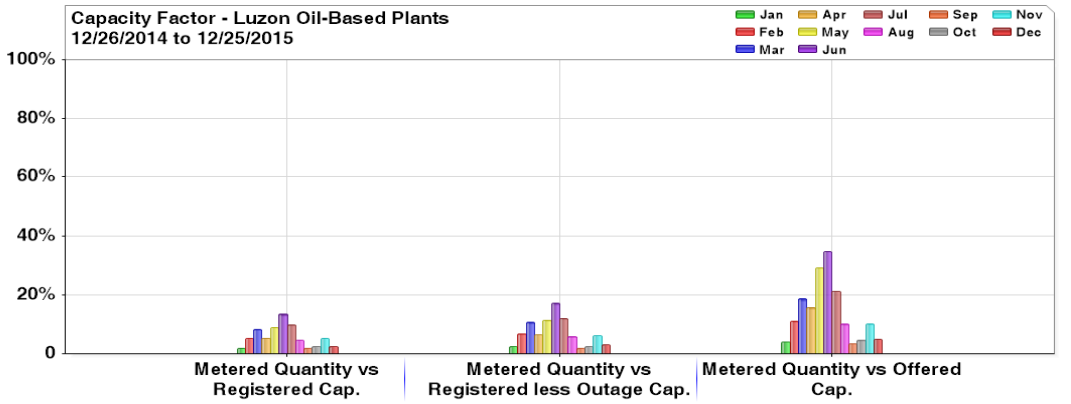

Figure 72 Capacity Factor - Luzon Oil-based Plants

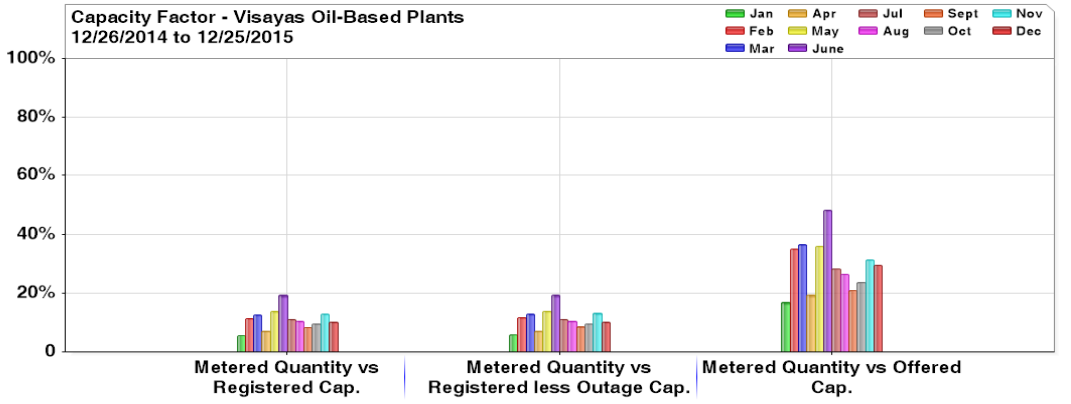

Figure 73 Capacity Factor - Visayas Oil-based Plants

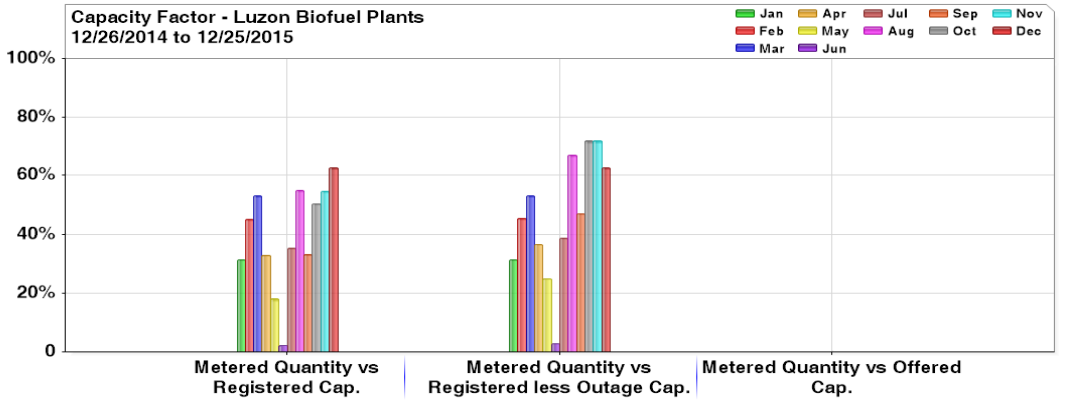

Figure 74 Capacity Factor - Luzon Biomass Plants

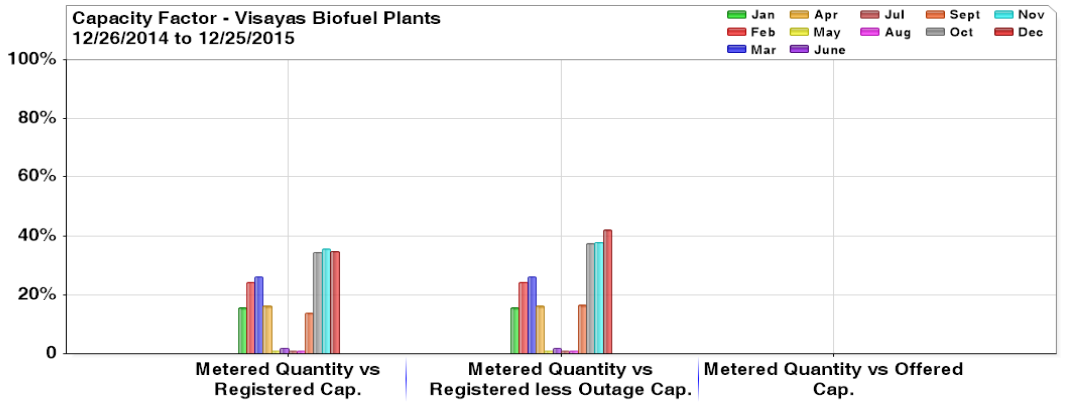

Figure 75 Capacity Factor - Visayas Biomass Plants

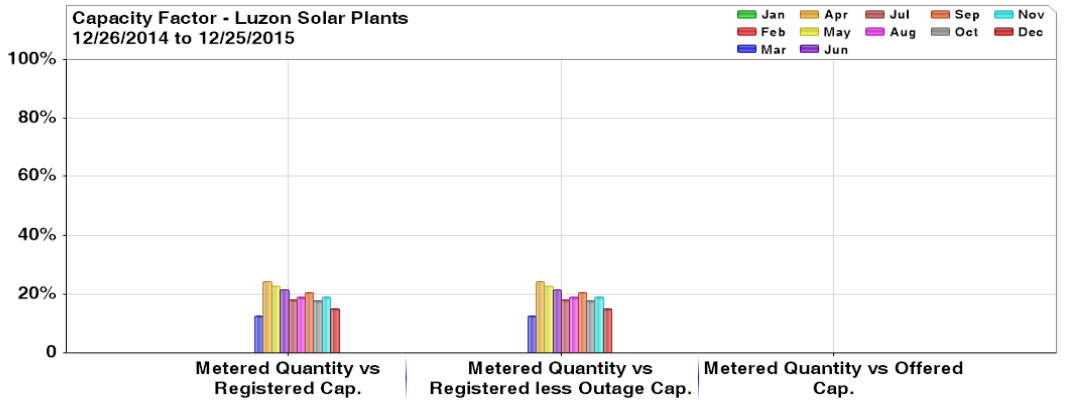

Figure 76 Capacity Factor - Luzon Solar Plants

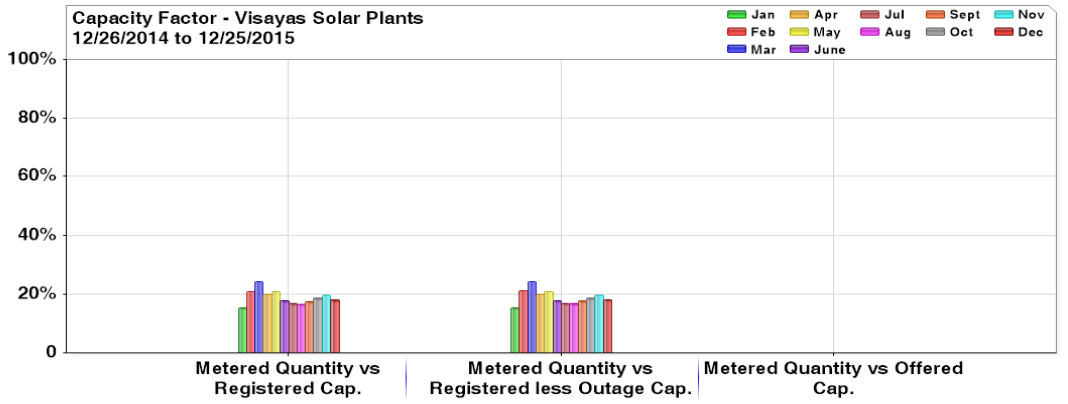

Figure 77 Capacity Factor - Visayas Solar Plants

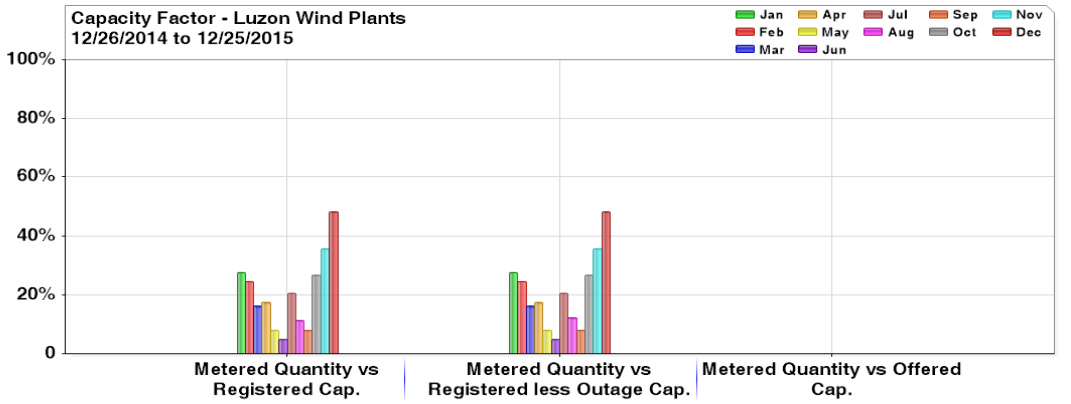

Figure 78 Capacity Factor - Luzon Wind Plants

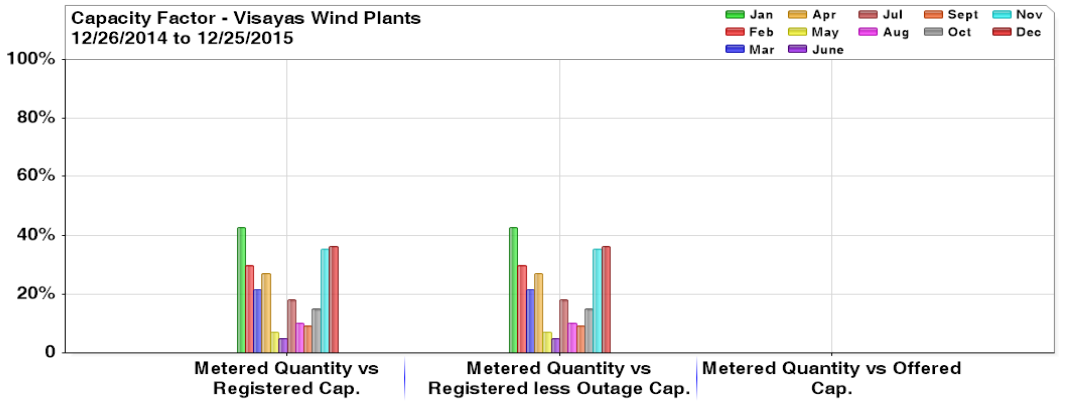

Figure 79 Capacity Factor - Visayas Wind Plants

Capacity Factor (%) by Billing Month, Luzon - 2015													
MQ vs. Registered Capacity													
Plant Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Avg.
Coal	50.7	50.7	60.3	70.9	72.5	72.0	65.1	61.4	59.1	56.8	59.8	53.0	61.0
Natural Gas	65.5	75.5	72.3	65.2	82.8	81.1	68.0	78.4	79.2	78.5	78.7	78.3	75.3
Geothermal	44.2	47.6	49.1	51.2	51.3	51.9	48.2	46.5	50.2	49.7	50.8	45.9	48.9
Hydro	20.5	18.3	16.7	13.1	11.2	14.2	24.8	29.1	32.3	29.7	23.1	23.5	21.4
Oil-Based	1.9	5.3	8.3	5.3	9.1	13.4	9.8	4.6	1.7	2.4	5.3	2.3	5.8
Wind	27.6	24.6	16.2	17.7	8.0	4.8	20.7	11.4	7.9	26.8	35.7	48.4	20.8
Solar	0.0	0.0	12.6	24.3	22.8	21.5	18.1	19.0	20.5	17.8	19.2	15.1	15.9
Biomass	31.4	45.2	53.3	32.9	18.0	2.1	35.4	55.1	33.1	50.6	54.8	62.9	39.6
MQ vs. Registered less Outage Capacity													
Plant Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Avg.
Coal	67.4	72.1	74.6	72.9	74.8	77.9	72.3	71.3	67.1	75.3	76.7	68.5	72.6
Natural Gas	75.6	81.9	82.3	79.3	84.1	87.8	87.6	81.2	79.7	80.1	83.4	80.2	81.9
Geothermal	73.8	81.9	82.3	79.3	84.1	87.8	87.6	81.2	79.7	80.1	83.4	80.2	81.9

Hydro	21.9	20.9	18.1	14.6	12.9	17.9	27.4	31.3	33.7	30.6	25.0	24.9	23.3
Oil-Based	2.4	6.7	10.6	6.6	11.5	17.4	12.1	5.7	1.8	2.4	6.3	3.0	7.2
Wind	27.7	24.6	16.2	17.7	8.0	4.8	20.7	12.2	8.1	26.8	35.7	48.4	20.9
Solar	0.0	0.0	12.6	24.3	22.8	21.5	18.1	19.0	20.5	17.8	19.2	15.1	15.9
Biomass	31.4	45.5	53.3	36.7	24.9	2.8	38.8	67.2	47.2	71.9	71.9	62.9	6.2
MQ vs. Offered Capacity													
Plant Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Avg.
Coal	75.4	85.8	87.9	84.1	86.2	90.8	85.5	85.6	80.9	87.1	88.4	80.6	84.9
Natural Gas	80.1	87.1	86.0	86.1	87.2	90.4	90.2	84.8	84.4	83.9	87.7	84.6	86.0
Geothermal	91.3	95.1	93.4	92.6	92.7	92.7	92.	92.5	93.1	92.6	93.3	90.5	92.7
Hydro	93.6	89.8	85.2	62.7	92.0	121.5	110.7	11.5	97.4	95.7	87.1	72.0	92.4
Oil-Based	4.1	11.2	18.7	15.8	29.3	34.9	21.3	10.1	3.5	4.5	10.3	5.0	14.1

Table 73 Capacity Factor by Plant Type - Luzon

Capacity Factor (%) by Billing Month, Luzon - 2015													
MQ vs. Registered Capacity													
Plant Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Avg.
Coal	51.7	53.3	46.5	58.5	59.7	62.2	69.4	65.9	61.7	61.2	54.3	57.4	58.5
Geothermal	68.8	73.2	75.0	74.4	76.5	75.8	77.6	74.7	76.6	74.5	75.2	72.7	74.6
Oil-Based	5.6	11.5	12.7	7.0	23.9	19.3	11.1	10.5	8.5	9.6	13.0	10.2	11.1
Wind	42.9	29.7	21.6	27.1	7.1	4.8	18.3	10.3	9.2	15.0	35.5	36.4	21.5
Solar	15.5	21.1	24.4	20.1	21.0	17.9	16.8	16.7	17.6	18.7	19.8	18.1	19.0
Biomass	15.7	24.2	6.8	16.2	1.0	1.9	1.0	0.9	13.9	34.5	35.6	34.8	17.2
MQ vs. Registered less Outage Capacity													
Plant Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Avg.
Coal	67.3	70.5	59.3	64.2	66.7	78.1	73.0	71.9	63.7	61.5	62.8	59.6	66.5
Geothermal	73.6	79.3	79.3	79.8	82.0	79.9	82.2	82.4	83.8	80.5	80.5	78.7	80.2
Oil-Based	5.8	11.7	12.9	7.0	14.0	19.4	11.2	10.5	8.5	9.7	13.1	10.2	11.2
Wind	42.9	29.7	21.6	27.1	7.1	4.8	18.3	10.3	9.2	15.0	35.5	36.4	21.5
Solar	15.5	21.2	24.4	20.1	21.0	17.9	16.9	16.8	17.8	18.7	19.8	18.2	19.0
Biomass	15.7	24.2	26.2	16.2	1.0	1.9	1.0	0.9	16.6	37.5	37.9	42.1	18.4
MQ vs. Offered Capacity													
Plant Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Avg.
Coal	73.8	83.4	75.2	73.0	75.9	80.4	73.4	73.7	67.0	65.3	65.4	61.8	72.4
Geothermal	92.4	94.7	95.5	94.1	93.9	95.1	95.4	95.3	96.8	94.2	96.7	93.0	94.8
Oil-Based	16.8	35.1	36.5	19.4	36.1	48.4	28.3	26.5	20.9	23.6	31.3	29.6	29.4

Table 74 Capacity Factor by Plant Type - Visayas

TRANSMISSION CONGESTION FREQUENCY INDICES

The Transmission Congestion Frequency Indices present the frequency of transmission congestions, which includes the constraints and congestion in generator and load-side substations, transmission lines, and those encountered by the submarine cable.

FREQUENCY OF ACTIVE CONSTRAINTS (EX-ANTE)

Majority or about 93.6 percent of the total constraints (4,482 of the total 4,789 constraints) at the load-side transformers were attributed to the Luzon region, while the Visayas region accounted for the remaining 3.2 percent (307 constraints).

Throughout the year, high occurrence of constraints were consistently observed at the Zapote transformer due to the violation of the contingency (N-1) requirement. This accounted for 75.3 percent (3,604 constraints) of the total occurrences of constraints at load-side transformers. Nevertheless, the same is lower than the total constraints on Zapote in the previous year at 3,840 constraints.

On the other hand, constraints on the Sta. Barbara and Cebu transformers accounted for the bulk of the constraints in the Visayas, with a total of 155 constraints and 102 constraints, respectively. Constraints at the load-side transformers in the Visayas were all attributable to base case constraints.

Region	Equipment	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Luzon	Cabanatuan Transformer	1							1					2
	San Jose EHV Transformer	1	3	57										61
	San Miguel EHV Transformer										3			3
	Laoag Tansformer			1										1
	La Trinidad Transformer	6	9							2				17
	San Esteban Transformer									2	7	1		10
	San Jose Transformer						2							2
	Santiago Transformer										2			2
	Tuguegarao Transformer					4	73	21	37	25	4			164
	Dona Imelda (Araneta) Transformer										5			5
	Dolores Transformer		12		10	20	62	22				2	2	130
	Muntinlupa Transformer			19	16	106	1	14						156
	Quezon (Balintawak) Transformer			3	31	57	51	19	25	50	19	7	5	267
	Zapote Transformer	160	278	332	399	467	392	273	323	335	274	237	134	3604
	Dasmariñas Transformer		13	6			12		2			7		40
	Kalayaan Transformer			5										5
	Tayabas Transformer								13					13
SUBTOTAL - LUZON		**168**	**315**	**423**	**456**	**654**	**593**	**349**	**401**	**404**	**314**	**254**	**141**	**4482**

Region	Equipment	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Visayas	Maasin Transformer					1								1
	Cebu Transformer							2		2	1	42	55	102
	Compostela Transformer											2		2
	Lapu-Lapu Transformer								8					8
	Mandaue Transformer		2				2		1	1				6
	Quit Transformer								1	1	5	2		9
	Kabankalan Transformer	1												1
	PEDC Transformer	20						1		2				23
	Sta. Barbara Transformer	2		1	9	19	11		8	38	22	38	7	155
SUBTOTAL - VISAYAS		**23**	**2**	**1**	**9**	**20**	**13**	**3**	**18**	**4**	**28**	**84**	**62**	**307**
TOTAL		**191**	**317**	**424**	**465**	**674**	**606**	**352**	**419**	**458**	**342**	**338**	**203**	**4789**

Table 75 Frequency of Constraints at Load-Side Transformers (Ex-Ante)

Base case constraints at several generator transformers were likewise observed this year, with the Visayas region accounting for 53 percent or 107 constraints of the total 202 constraints for the billing year 2015. Meanwhile, 47 percent was attributable to Luzon, accounting for the 95 constraints which occurred at the generator transformers in the region.

Region	Equipment	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Luzon	Angat Transformer			2	1								2	5
	Bakun Transformer					1		1	17		1			20
	Burgos Transformer										3			3
	Casecnan Transformer										1			1
	Subic Transformer	6	32											38
	Bacman Transformer		5	1		1		2	3		1	3	1	17
	Ilijan Transformer	1											2	3
	Makban A Transformer								3	1	4			8
SUBTOTAL - LUZON		**7**	**37**	**3**	**1**	**2**	**0**	**3**	**23**	**1**	**10**	**3**	**5**	**95**
Visayas	Tongonan Transformer	51	1	3	1		4		6		2	1	1	70
	CEDC Transformer			1		1	1			1	3			7
	KSPC Transformer		7											7
	Palinpinon GPP 1 Transformer		1	3	2	1		1		1		1		10
	Palinpinon GPP 2 Transformer	1			1	2	4	1		1	2	1		13
SUBTOTAL - VISAYAS		**52**	**9**	**7**	**4**	**4**	**9**	**2**	**6**	**3**	**7**	**3**	**1**	**107**
TOTAL		**59**	**46**	**10**	**5**	**6**	**9**	**5**	**29**	**4**	**17**	**6**	**6**	**202**

Table 76 Frequency of Constraints at Generator Transformers (Ex-Ante)

Constraints on transmission lines totalled 1,064 for this year, with about 56.6 percent of which attributed to Luzon, affecting 602 trading intervals, and 43.4 percent, to the transmission lines in the Visayas, affecting a total of 462 intervals.

Higher occurrences of constraints were observed at the Toledo-New Naga 138 kV Line which accounted for 34.5 percent (367 constraints), and Bauang-BPPC 230 kV Line which accounted for about 31.7 percent (337 constraints) of the total constraints for the billing year.

Region	Equipment	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Luzon	Bauang-BPPC 230kV Line		8	5		48	192	81			1			337
	Bauang-Kadampat 230kV Line		1	1										2
	Bauang-La Trinidad 230kV Line					18		2						20
	Binga-San Manual 230kV Line										25			25
	BPPC-Kadampat 230kV Line		8			9					4			21
	Currimao-Bantay 115kV Line										4	1		5
	Kadampat-Sual 230kV Line				4									4
	Laoag-Currimao 115kV Line										5	1		6
	Labrador-Botolan 230kV Line									3				3
	Mexico-Hermosa 230kV Line						34	16						50
	San Jose (EHV)-San Jose 230kV Tie-Line			26									1	27
	San Jose-Dolores 230kV Line												1	1
	San Miguel (New)-San Miguel (Old) 230kV Tie-Line									11	4			15
	Balintawak-San Jose 230kV Line						7		11	25			1	44
	Dolores-Malaya 230kV Line												1	1
	Amadeo-Calaca 230kV Line		24							1				25
	Calauan-Makban A 230kV Line		2	6	2									10
	Dasmariñas-Amadeo 230kV Line			3						1				1
	Kalayaan-Makban A 230kV Line													3
	Sta. Rosa-Calaca 230kV Line									2				2
SUBTOTAL - LUZON		**0**	**43**	**41**	**6**	**75**	**233**	**99**	**11**	**43**	**43**	**2**	**6**	**602**
Visayas	Central (Switching Station)-Tabango 230kV Line					2								2
	Cebu-Mandaue 138kV Line											1		1
	New Naga-Cebu 138kV Line	1				6								7
	New Naga-KSPC 138kV Line											4		4
	Quiot-New Naga 138kV Line					2	6	25	1		1		18	53

Region	Equipment	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Visayas	Toledo-New Naga 138kV Line	16	2	34	13	31	114	58	67	21	5	2	4	367
	Quiot-Cebu 138kV Line							1						1
	Calung-Calung-Toledo 138kV Line				6								2	8
	Amlan-Mabinay 138kV Line			2										2
	Mabinay-Kabangkalan 138kV Line			7						10				17
SUBTOTAL - VISAYAS		**17**	**2**	**43**	**19**	**41**	**120**	**84**	**68**	**31**	**6**	**7**	**24**	**462**
TOTAL		**17**	**45**	**84**	**25**	**116**	**353**	**183**	**79**	**74**	**49**	**9**	**30**	**1064**

Table 77 Frequency of Constraints at Transmission Lines (Ex-Ante)

The Visayas submarine cables were likewise with constraints, with the Negros-Panay submarine cable accounting for majority or 67.9 percent (471 constraints) of the total 694 constraints, followed by the Leyte-Cebu submarine cable with 25.5 percent or 177 constraints.

Region	Equipment	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Visayas	Leyte-Bohol Submarine Cable					1								1
	Leyte-Cebu Submarine Cable	1	20	12	2	7	50	2	15	26	3	29	10	177
	Cebu-Negros Submarine Cable		4	1		1			17	9	1	8	4	45
	Negros-Panay Submarine Cable	51	84	7	103	61	9	14	35	101		5	1	471
TOTAL		**52**	**108**	**20**	**105**	**70**	**59**	**16**	**67**	**136**	**4**	**42**	**15**	**694**

Table 78 Frequency of Constraints at Submarine Cable (Ex-Ante)

FREQUENCY OF ACTIVE CONSTRAINTS (EX-POST)

Occurrences of constraints were likewise observed during the ex-post on load-side transformers, though these were notably lower than the frequency of constraints during the ex-ante.

A total of 468 constraints at the load-side transformers were observed during ex-post, 52.6 percent (246 constraints) of which were on account of the load-side transformers in Luzon, while 47.4 percent (222 constraints) of which were attributed to the Visayas.

Region	Equipment	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Luzon	Cabanatuan Transformer								1					1
	La Trinidad Transformer	1												1
	San Esteban Transformer							1		2	6	1		10
	Tuguegarao Transformer					6	86	31	50	41	6			220
	Quezon (Balintawak) Transformer					2	3							5
	Dasmariñas Transformer											5		5
	Kalayaan Transformer	4												4
SUBTOTAL - LUZON		**5**	**0**	**0**	**0**	**8**	**89**	**32**	**51**	**43**	**12**	**6**	**0**	**246**
Visays	Maasin Transformer									1				1
	Cebu Transformer							2	1	2	1	32	37	75
	Compostela Transformer													2
	Lapu-Lapu Transformer								9					9
	Mandaue Transformer					4	4		1	2				11
	Quiot Transformer								1	2	6	2		11
	Kabankalan Transformer	5												5
	PEDC Transformer	4			1			2	1	3				11
	Sta. Barbara Transformer				4	41	28	2	5	8	6	3		97
SUBTOTAL - VISAYAS		**9**	**0**	**0**	**5**	**45**	**32**	**6**	**18**	**18**	**13**	**39**	**37**	**222**
TOTAL		**14**	**0**	**0**	**5**	**53**	**121**	**38**	**69**	**61**	**25**	**45**	**37**	**468**

Table 79 Frequency of Constraints at Load-Side Substations (Ex-Post)

Constraints at generator transformers were also observed during ex-post, affecting a total of 205 trading intervals. 42.4 percent (87 constraints) were attributed to Luzon and 57.6 percent (118 constraints) were attributed to Visayas.

Region	Equipment	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Luzon	Angat Transformer													2
	Bakun Transformer					1		1	19		1			22
	Burgos Transformer										7			7
	Casecnan Transformer										1			1
	Subic Transformer	5	26											31
	Bacman Transformer		6			1		1	4		2	4	3	21
	Ilijan Transformer												3	3
	Makban A Transformer								3	1	3			7
SUBTOTAL - LUZON		**5**	**32**	**0**	**0**	**2**	**0**	**2**	**26**	**1**	**14**	**4**	**8**	**87**

Region	Equipment	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Visayas	Tongonan Transformer	50	1	3			5		6		3	1		69
	CEDC Transformer			1			3			2	2		2	10
	KSPC Transformer		6											6
	Palinpinon GPP 1 Transformer		1	5	2			2		3				13
	Palinpinon GPP 2 Transformer	2			4	3	7	2			1		1	20
SUBTOTAL - VISAYAS		**52**	**8**	**9**	**6**	**3**	**15**	**4**	**6**	**5**	**6**	**1**	**3**	**118**
TOTAL		**57**	**40**	**9**	**6**	**5**	**15**	**6**	**32**	**6**	**20**	**5**	**11**	**205**

Table 80 Frequency of Constraints at Generator Transformers (Ex-Post)

Decline in the frequency of constraints at transmission lines were similarly observed during ex-post, occurring in 431 trading intervals. About 85.2 percent (367 constraints) were on account of the constraints imposed on the transmission lines in the Visayas, while 14.8 percent (64 constraints) were observed in Luzon. Majority of these constraints or 66.1 percent (285 constraints) were observed in the Toledo-New Naga 138kV Line.

Region	Equipment	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Luzon	Bauang-BPPC 230kV Line					4	29	1						34
	Binga-San Manuel 230kV Line										18			18
	Bantay-San Esteban 115kV Line										1			1
	Currimao-Bantay 115kV Line										2	1		3
	Kadampat-Sual 230kV Line				1									1
	Laoag-Currimao 115kV Line										4	1		5
	Sta. Rosa-Calaca 230kV Line									2				2
SUBTOTAL - LUZON		**0**	**0**	**0**	**1**	**4**	**29**	**1**	**0**	**2**	**25**	**2**	**0**	**64**
Visayas	Central (Switching Station)-Tabango 230kV Line					1								1
	New Naga-Cebu 138kV Line	1				7	2		1					11
	New Naga-KSPC 138kV Line											2		2
	Quiot-New Naga 138kV Line			1	1	1	6	14	3	2	1		29	58
	Toledo-New Naga 138kV Line	13		30	10	21	88	48	55	18	2			285
	Calung-Calung-Toledo 138kV Line				6								1	7
	Amlan-Mabinay 138kV Line			2										2
	Mabinay-Kabangkalan 138kV Line									1				1
SUBTOTAL - VISAYAS		**14**	**0**	**33**	**17**	**30**	**96**	**62**	**59**	**21**	**3**	**2**	**30**	**367**
TOTAL		**14**	**0**	**33**	**18**	**34**	**125**	**63**	**59**	**23**	**28**	**4**	**30**	**431**

Table 81 Frequency of Constraints at Transmission Lines (Ex-Post)

Occurrences of constraints at the Visayas submarine cables during ex-post were likewise observed in 239 trading intervals. 108 of these constraints were on the Negros-Panay submarine cable while 93 constraints were constraints at the Leyte-Cebu submarine cable.

Region	Equipment	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Visaysa	Leyte-Cebu Submarine Cable		14			6	38	1	9	12		9	4	93
	Cebu-Negros Submarine Cable		2			4		1	15	9		3	4	38
	Negros-Panay Submarine Cable	24	17	1	19	18	1		3	22	1		2	108
TOTAL		**24**	**33**	**1**	**19**	**28**	**39**	**2**	**27**	**43**	**1**	**12**	**10**	**239**

Table 82 Frequency of Constraints at Submarine Cable (Ex-Post)

OVER-RIDING CONSTRAINTS

Over-riding constraints, as defined in the WESM Rules[25], are constraints imposed in the market dispatch optimization model (MDOM) by the MO, at the recommendation of the SO, with the intention of over-riding the effect of a Trading Participant's offers or demand bids. The categories of the over-riding events throughout the year are based on the data and information provided by the SO.

Overall, about 87.3 percent (46,221 events) of the total 52,970 constraints[26] system-wide were impositions made on the generators in Luzon while the remaining 12.7 percent (6,749 events) were constraints imposed on Visayas generators.

It is observed that the number of over-riding events were higher particularly during the second half of the billing year, with the most number of events recorded during the October billing month, with a total of 6,050 events.

By category, about 84.5 percent (44,743 events) of the total over-riding events arose from the imposition of security limit, and 15.5 percent (8,209 events) were on account of the SO's designation of must-run-units (MRUs). Looking at the Table below, It is important to note that the number of system wide over-riding events categorized under security limit increased significantly from only 128 events in February to 4,247 events in March, as activities and tests related to Commercial Operation Requirements, such as commissioning tests, are no longer included in the criteria under MRU and were instead categorized under security limit effective 11 February[27] following the revision of the criteria in the selection of MRUs. This resulted in the categorization of the conduct of commercial tests under security limit, which drove the increase in the number of security limit events (from 128 events to 4,247 events) and correspondingly, decrease in MRU events (from 3,725 events to 0 events), starting in March and consistently so until yearend. Security limit events were then observed to range from a minimum of 3,208

25 WESM Rules, Chapter 11 (Glossary)

26 The monitoring of the over-riding constraints on generators is done on a per generator trading node per trading interval. A constraint imposed on a generator trading node on a particular trading interval is considered as one over-riding event. The monitoring of the over-riding constraints is based on the data and information provided by MO (i.e. real time market results and MMS-input files on security limits) and SO (i.e. SO Data for Market Monitoring).

27 Effective date of the WESM Manual on the Management of Must-Run and Must-Stop Units Issue 5.0.

events in May and a maximum of 6,050 events in October, while there were 0 MRU events beginning the March billing month.

Increase in the number of over-riding events from a total of only 18,608 events in 2014 were mainly attributable to the entry of new plants in the market, most of which underwent commissioning in year 2015. New plants which registered in the market in the last quarter of 2014 but underwent or continued with their conduct of commissioning tests in 2015 influenced the number of over-riding events during the period, particularly during the first half of the billing year, when the combined level of commissioning from these plants were within the range of 1 MW to 281 MW in various trading intervals. These plants include San Jose City I Power Corp. (IPOWER), Universal Robina Corp. (URC Biomass), South Luzon Thermal Energy Corp. (SLTEC 1), Energy Development Corporation (Nasulo), Lafarge Republic, Inc. (LAFARG 1 and 2), San Carlos Energy Inc. (SACASL 1), EDC Burgos Wind Power Corp. (Burgos 1), North Luzon Renewable Energy Corp. (CAPRIS), North Wind Power Development Corp. (NWIND 2) and Trans-Asia Renewable Energy Corp (SLWIND).

Meanwhile, the conduct of commissioning tests of new plants which registered in the market during the course of billing year 2015 augmented the effective supply by as much as 428 MW. The combined level of commissioning from said new plants were observed to be between 0.1 MW and 142 MW during the first semester of the billing year in various trading intervals, and between 0.5 MW and 428 MW during the second semester. As shown in Table 85, higher commissioning levels from the entry of these new plants were observed particularly during the August, September and October billing months.

Summary of Over-riding Events by Category, 2016

Category	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
LUZON													
MRU	3,798	3,081											6,879
Security Limit	109	41	3,510	3,664	2,818	3,469	4,561	4,096	4,547	5,306	3,688	3,533	39,342
Subtotal - Luzon	3,907	3,122	3,510	3,664	2,818	3,469	4,561	4,096	4,547	5,306	3,688	3,533	46,221
VISAYAS													
Generator Limitation	18												18
MRU	686	644											1,330
Security Limit	94	87	737	923	390	315	341	32	123	744	865	750	5,401
Subtotal - Visayas	798	731	737	923	390	315	341	32	123	744	865	750	6,749
Grand Total	**4,705**	**3,853**	**4,247**	**4,587**	**3,208**	**3,784**	**4,902**	**4,128**	**4,670**	**6,050**	**4,553**	**4,283**	**52,970**

Table 83 Summary of Over-riding Events by Category

Monthly Commissioning Levels (MW) of New Plants, 2015

Station Node Name	Mar		Apr		May		Jun		Jul	
	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max
1ANDA_G01							8.37	35	15	73
1BT2020_G01									1.3	12
1IBEC_G01										
1RASLAG_G01							0.1	7.5	0.2	7.5
1SABANG_G01					1.8	7	2.5	14.5	3.3	14
2MGTPP_G01	30	100	5	100	50	50	50	100		
3MEC_G01	2	35	0.1	36	0.1	30	1	30	0.5	30
3SLPGC_G01									7.5	120

Monthly Commissioning Levels (MW) of New Plants, 2015										
3SLPGC_G02										
3SLTEC_G02										
6HPCO_G01			2.5	8						
continuation...	Aug		Sep		Oct		Nov		Dec	
	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max
1ANDA_G01	17	73	15	97	1	72	25	72	25	72
1BT2020_G01										
1IBEC_G01			3	8	2.5	18.5	18	18	18	18
1RASLAG_G01										
1SABANG_G01	5.8	14	7.75	14	1.68	14				
2MGTPP_G01			80	85						
3MEC_G01	0.5	29	0.5	31.5	0.1	32	0.1	31.5	0.5	29.5
3SLPGC_G01	10	150	10	150	40	150				
3SLPGC_G02	10	30	7.5	90	20	50	20	90	10	150
3SLTEC_G02	5	95	2.6	124			5.5	124		
6HPCO_G01										

Table 84 Monthly Commissioning Levels (MW) of New Plants

Wind plants contributed the highest number of over-riding events per plant type with a total 27,063 events, correspondingly accounting for 51.1 percent of the total over-riding events this year, followed by coal plants with a total of 9,773 events or 18.5 percent, biomass plants with 4,810 events or 9.1 percent, hydro plants with 4,228 events which comprised about 8 percent of the total over-riding events for 2015 and solar plants, with 4,153 events or 7.8 percent. Distantly following are the over-riding events attributed to natural gas plants with 1,629 events (3.1 percent), oil-based plants with 752 events (1.4 percent) and geothermal plants with 562 events (1.1 percent).

The high incidence of over-riding events among wind plants was mainly attributable to the conduct of commissioning tests of NWIND 1 and 2, Capris, Burgos and SLWind. Also, over-riding events were similarly high among coal plants particularly during the last quarter of the year, on account of the increased over-riding constraints on new coal plants Anda and SLPGC as well as coal plant TPC (Sangi) in the Visayas.

Biofuel plants likewise recorded a relatively high number of over-riding constraints, mostly during the first and last quarters of the year. IPOWER posted the highest number of over-riding events among biomass plants in the first quarter following its conduct of commissioning tests, while biofuel plant IBEC accounted for the overall increase in over-riding events among this plant type in the last quarter.

On the other hand, increase in the over-riding constraints among hydro plants was observed from June to October, on account of the notable rise in the imposition of security limit on Sabangan HEP during this month. Increase in the over-riding constraints on solar plants was also observed during the second and third quarters of the year due to the commissioning tests of solar plants Majestics Energy (MEC) and RASLAG during these months.

Summary of Over-riding Events by Plant Type, 2015													
Category	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
LUZON													
BIOF	709	638	668	358			14		29	717	744	720	4,597
COAL	537	3	309	542	27	40	342	866	1,336	1,110	815	984	6,911
GEO	37	168	1									21	227
HYD	54	54	98	5	117	696	766	750	755	710	83	140	4,228
NATG	291	45	146	40	139	260	357	100	8	23	41	179	1,629
OIL	34	39	116	102	36	89	117	51	32	22	105		743
SOLR			207	387	385	727	599	400	381	357	370	328	4,141
WIND	2,245	2,175	1,965	2,230	2,114	1,657	2,366	1,929	2,006	2,367	1,530	1,161	23,745
Subtotal - Luzon	3,907	3,122	3,510	3,664	2,818	3,469	4,561	4,096	4,547	5,306	3,688	3,533	46,221
VISAYAS													
BIOF				213									213
COAL	43	32	198	19	83	112	16	26	103	700	785	745	2,862
GEO	18		7	18		201			13	23	50	5	335
OIL	3	3							3				9
SOLR				12									12
WIND	734	696	532	661	307	2	325	6	4	21	30		3,318
Subtotal - Visayas	798	731	737	923	390	315	341	32	123	744	865	750	6,749
Grand Total	**4,705**	**3,853**	**4,247**	**4,587**	**3,208**	**3,784**	**4,902**	**4,128**	**4,670**	**6,050**	**4,553**	**4,283**	**52,970**

Table 85 Summary of Over-riding Events by Plant Type

Tables 87 and 88 as shown below summarize the impact of the over-riding constraints imposed on generators on the supply and Pmin (or price-taker level) for the duration of the 2015 billing period.

The imposition of over-riding constraints on generators[28] affected 8,719 trading intervals or 95.6 percent of the total trading intervals in 2015, with a corresponding increase in supply[29] of 147 MW on the average. Increase in the supply taking into account the imposed over-riding constraints were mostly ranging between above 50 MW to 350 MW across all billing months. The maximum increase in supply was posted at 678 MW in April following the additional capacities brought about by the conduct of commissioning tests of biofuel plant IPOWER, wind plants Capris, Burgos, NWind 1 and SLWind and solar plant Majestics Energy (MEC).

In addition, the imposition of over-riding constraints as shown in Table 87 resulted in higher Pmin or price taker levels 99 percent of the time, or in almost all the trading intervals during the 2015 billing period, corresponding to an average increase in Pmin of 197 MW. It is observed that the highest Pmin level increase was posted in October at an average of 298 MW. Note that the ratio of Pmin to the demand during year was 48 percent. Taking into account the effect of the imposed over-riding constraints on the Pmin level, the ratio grew to 50.5 percent, indicating that the contestable demand was reduced by an average of about 2.5 percent.

28 Excluding the other constraints considered in the MMS (e.g. ramp rate offers).
29 The supply is equal to the total offered capacity of all generator resources, including Pmin, adjusted for any security limit provided by the NGCP-System Operator.

Summary of Aggregate Offer and Supply Comparison, 2015													
Increase / Decrease in Supply (Offer with Limit)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
-650MW to -600MW	-	-	-	-	-	-	-	-	0.1	-	-	-	0.0
-600MW to -550MW	-	-	-	-	-	-	-	-	0.4	-	-	-	0.0
-550MW to -500MW	-	-	-	-	-	-	-	-	0.4	-	-	-	0.0
-500MW to -450MW	-	-	-	-	-	-	-	-	0.4	-	-	-	0.0
-450MW to -400MW	-	-	-	-	0.1	-	-	-	-	-	-	-	0.0
-400MW to -350MW	-	-	0.3	-	0.1	-	-	-	-	-	-	-	0.0
-350MW to -300MW	-	-	1.4	-	-	-	-	-	-	-	-	-	0.1
-300MW to -250MW	-	-	0.5	-	-	-	-	-	-	-	0.4	-	0.1
-250MW to -200MW	-	-	1.7	-	0.1	0.1	0.1	-	0.1	-	0.7	0.1	0.2
>-200MW to -150MW	-	0.5	0.8	0.3	0.8	-	0.3	0.3	0.4	-	0.3	0.8	0.4
>-150MW to -100MW	-	0.4	1.2	0.3	2.4	0.5	-	4.6	-	-	1.5	0.7	1.0
>-100MW to -50MW	0.7	0.7	3.3	1.9	2.2	2.2	0.3	5.0	0.3	0.3	5.4	7.7	2.5
>-50MW to 0MW	-	-	-	-	0.1	-	-	-	-	-	-	-	0.0
>0MW to 50MW	-	-	0.2	0.1	0.1	0.1	-	-	-	-	-	-	0.0
>50MW to 100MW	4.2	12.5	11.7	4.3	30.1	54.3	10.9	15.2	7.7	2.9	16.0	18.4	15.7
>100MW to 150MW	3.2	12.3	14.8	16.8	31.9	18.8	12.5	11.7	8.4	6.1	17.2	17.6	14.3
>150MW to 200MW	16.8	32.5	27.6	9.6	17.4	8.8	27.4	20.0	17.6	15.5	15.1	21.8	19.0
>200MW to 250MW	8.4	39.2	18.1	26.3	4.3	10.5	25.9	12.3	14.0	16.3	13.1	14.6	16.9
>250MW to 300MW	27.1	1.6	9.8	17.4	4.6	4.0	9.3	18.9	19.3	19.4	11.2	14.4	13.1
>300MW to 350MW	32.1	0.1	2.6	16.6	5.1	0.1	4.3	8.5	17.6	11.5	9.4	-	9.1
>350MW to 400MW	1.5	-	3.3	2.2	0.4	0.4	3.8	1.8	6.3	11.9	2.4	-	2.8
>400MW to 450MW	0.8	-	1.1	1.6	-	0.1	2.1	0.5	3.7	9.6	1.1	1.3	1.8
>450MW to 500MW	5.3	-	1.8	0.9	-	-	1.9	0.5	1.5	5.0	4.2	2.6	2.0
>500MW to 550MW	-	-	0.2	1.1	-	-	0.6	0.1	1.2	1.4	2.2	-	0.6
>550MW to 600MW	-	-	-	0.3	-	-	0.4	0.4	0.4	-	-	-	0.1
>600MW to 650MW	-	-	-	0.1	-	-	-	0.1	0.1	-	-	-	0.0
>650MW to 700MW	-	-	-	0.1	-	-	0.1	-	-	-	-	-	0.0
700MW to 750MW	-	-	-	0.1	-	-	-	-	-	-	-	-	0.0

Summary of Aggregate Pmin Comparison, 2015													
Increase / Decrese in Pmin Level (Price Taker)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Below 0 MW	0.5	0.1	3.4	-	1.7	1.2	-	8.1	-	-	0.3	-	1.3
>0MW to 50MW	0.1	1.8	0.6	-	-	0.3	0.1	0.1	1.1	0.6	-	0.1	0.4
>50MW to 100MW	2.4	8.0	5.4	3.2	30.6	46.7	7.6	14.4	6.2	-	0.3	2.1	10.6
>100MW to 150MW	2.3	11.1	14.2	16.0	31.3	17.4	11.1	10.1	6.8	2.9	10.1	13.5	12.2
>150MW to 200MW	12.2	30.2	24.0	8.5	17.4	9.0	21.3	17.8	10.4	6.3	15.7	21.1	16.1
>200MW to 250MW	8.6	39.4	14.2	25.5	3.9	8.7	20.3	14.5	13.0	6.7	14.2	11.7	15.1
>250MW to 300MW	26.5	7.4	10.3	18.8	5.0	10.5	10.6	18.2	23.3	17.5	18.3	18.2	15.4
>300MW to 350MW	24.4	1.9	6.4	17.1	6.0	2.4	7.2	9.2	19.7	17.1	12.1	11.3	11.3
>350MW to 400MW	7.4	0.3	5.5	3.6	2.1	0.4	10.4	2.4	6.5	20.7	10.2	7.1	6.4
>400MW to 450MW	2.3	-	6.0	2.3	0.6	2.6	6.1	0.9	4.2	13.1	9.7	0.6	3.8
>450MW to 500MW	6.7	-	4.9	2.4	-	0.8	2.2	1.1	2.2	8.1	2.8	2.2	2.8
>500MW to 550MW	3.6	-	1.6	0.7	0.1	-	0.7	1.1	2.7	4.2	4.7	3.2	1.9
>550MW to 600MW	1.1	-	0.1	0.4	0.4	-	1.0	0.3	1.4	1.0	2.7	5.0	1.1
>600MW to 650MW	-	-	0.4	0.4	-	-	0.4	0.7	1.2	0.3	0.9	0.6	0.4
>650MW to 700MW	1.7	-	-	0.1	0.3	-	0.3	0.8	0.9	0.6	0.1	0.1	0.4
.700MW to 750MW	-	-	2.7	0.3	-	-	0.4	0.3	0.1	1.0	0.5	2.4	0.6
>750MW to 800MW	-	-	-	0.7	0.4	-	-	0.1	0.1	0.3	0.1	0.8	0.2
>800MW to 850MW	-	-	-	-	0.3	-	0.1	-	-	-	0.1	-	0.0
>850MW to 900MW	-	-	-	-	0.1	-	-	-	-	-	-	-	0.0

Table 87 Summary of Aggregate Pmin Comparison

SPOT MARKET EXPOSURE[30]

GENERATOR

The generator's spot market exposure is equivalent to the percentage of energy injected not covered by the bilateral contracts entered into between generators and customers.

For 2015, the spot market exposure of generators averaged at 12.0 percent, while the remaining 88.0 percent was covered by bilateral contracts. The billing months of March, April and July posted the highest monthly spot exposure among generators at an average of 13.5 percent, 13.6 percent and 13.4 percent, respectively. On the other hand, the January billing month posted the lowest spot exposure among generators this year with only 9.6 percent.

Year-on-year comparison demonstrates a minimal increase of 0.8 percent in the average spot exposure of generators from last year's 11.2 percent. Nevertheless, the volume of spot transactions posted an increase this year by about 13.4 percent, averaging at 658,888/MWh from last year's 581,137/MWh. The total metered quantity of generators likewise rose by 5.9 percent, from last year's 5,188,447/MWh to 5,494,333/MWh. Correspondingly, increase by about 5 percent was observed this year in the bilateral contract quantities of generators from an average of 4,607,311/MWh last year to 4,835,446/MWh in 2015.

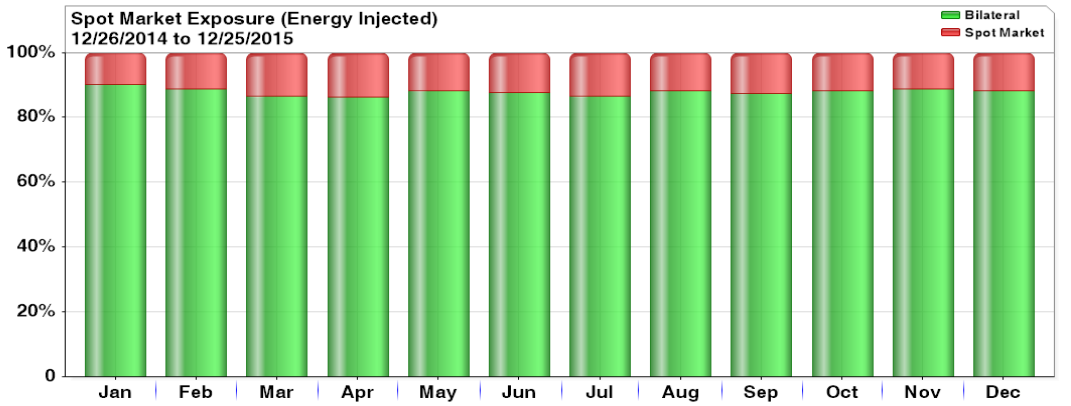

Figure 80 Generator's Spot Market Exposure - System

	Generator's Spot Exposure by Billing Month - 2015						
	Jan	Feb	Mar	Apr	May	Jun	Jul
Metered Qty (MWh)	4,672,655	5,058,833	4,818,110	5,542,538	5,813,934	6,068,331	5,548,514
Bilateral Qty (MWh)	4,222,346	4,498,807	4,167,551	4,786,512	5,129,029	5,328,603	4,803,784
Spot Market Qty (MWh)	450,309	560,026	650,559	756,026	684,905	739,728	744,731
Bilateral Qty (%)	90.4	88.9	86.5	86.4	88.2	87.8	86.6
Spot Market (%)	9.6	11.1	13.5	13.6	11.8	12.2	13.4

30 The spot market exposure is the difference between the total energy transacted in the market and the bilateral contract quantity (BCQ). This measures the extent by which trading participants are exposed to the hourly spot price volatility in the market.

	Generator's Spot Exposure by Billing Month - 2015					
continuation...	Aug	Sep	Oct	Nov	Dec	Annual Avg
Metered Qty (MWh)	5,794,802	5,826,807	5,588,106	5,843,477	5,355,893	5,494,333
Bilateral Qty (MWh)	5,117,646	5,103,548	4,936,202	5,195,422	4,735,896	4,835,446
Spot Market Qty (MWh)	677,155	723,259	651,90	648,055	619,998	658,888
Bilateral Qty (%)	88.3	87.6	88.3	88.9	88.4	88.0
Spot Market (%)	11.7	12.4	11.7	11.1	11.6	12.0

Table 88 Generators' Spot Market Exposure

	Year-on-Year Comparison of Generator's Monthly Spot Exposure - System						
	Jan	Feb	Mar	Apr	May	Jun	Jul
2015 (%) Spot Exposure	9.6	11.1	13.5	13.6	11.8	12.2	13.4
2014 (%) Spot Exposure	10.0	13.0	12.6	11.4	10.5	11.4	12.2
Y-Y (%) Change	(0.4)	(1.9)	0.9	2.3	1.2	0.8	1.3
continuation...	Aug	Sep	Oct	Nov	Dec	Annual Avg	
2015 (%) Spot Exposure	11.7	12.4	11.7	11.1	11.6	12.0	
2014 (%) Spot Exposure	9.4	10.5	12.1	10.7	11.0	11.2	
Y-Y (%) Change	2.3	1.9	(0.5)	0.4	0.6	0.8	

Table 89 Year-on-Year Comparison of Generators' Spot Market Exposure

The spot market exposure of Luzon generators averaged at 9.8 percent for billing year 2015 and the remaining majority of 90.2 percent of the total energy injected was covered by bilateral contracts. The billing months of March, April and July recorded the highest monthly spot exposure at 11.2 percent, 11.9 percent and 11.5 percent, respectively, while the billing months which registered the lowest spot exposure in the region were the January and February billing months, with 7.6 and 8 percent, respectively.

Year-on-year comparison in terms of the volume of spot transactions in the region demonstrated a 3.7 percent increase from last year's average of 440,938/MWh to 457,285/MWh. However, the total metered quantity was noted to have increased by 5.3 percent from an average of 4,402,025/MWh to 4,633,200/MWh this year. Similarly, increase in the region's bilateral contract quantities from the previous year was noted at 5.4 percent from 3,961,087/MWh in 2014 to 4,175,916/MWh.

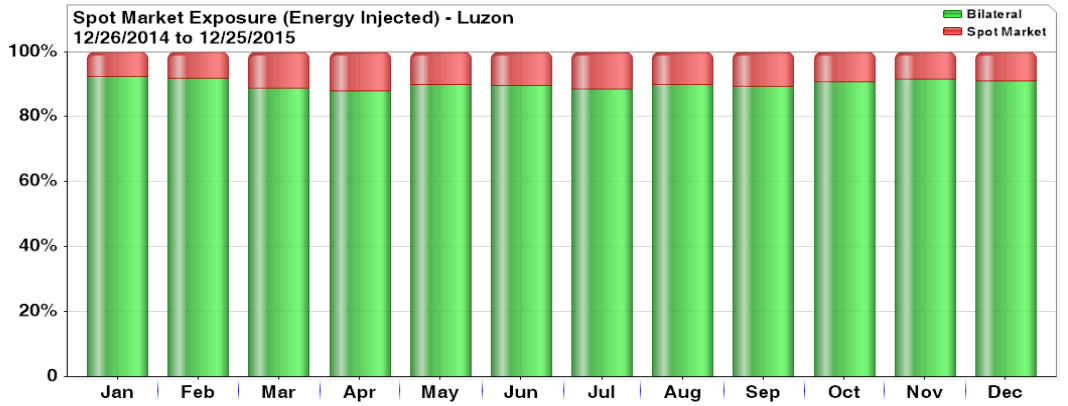

Figure 81 Luzon Generator's Spot Market Exposure

	Generator's Spot Exposure by Billing Month - Luzon, 2015						
	Jan	Feb	Mar	Apr	May	Jun	Jul
Metered Qty (MWh)	3,874,899	4,200,856	4,064,626	4,660,936	4,940,960	5,180,973	4,661,036
Bilateral Qty (MWh)	3,580,120	3,862,701	3,609,518	4,106,315	4,449,922	4,645,992	4,123,224
Spot Market Qty (MWh)	294,780	338,155	455,108	554,622	491,038	534,981	537,812
Bilateral Qty (%)	92.4	92.0	88.8	88.1	90.1	89.7	88.5
Spot Market (%)	7.6	8.0	11.2	11.9	9.9	10.3	11.5
continuation...	Aug	Sep	Oct	Nov	Dec	Annual Avg	
Metered Qty (MWh)	4,921,910	4,952,655	4,709,908	4,942,540	4,487,102	4,633,200	
Bilateral Qty (MWh)	4,422,080	4,423,565	4,273,434	4,524,771	4,089,344	4,175,916	
Spot Market Qty (MWh)	499,829	529,090	436,474	417,769	397,758	457,285	
Bilateral Qty (%)	89.8	89.3	90.7	91.5	91.1	90.2	
Spot Market (%)	10.2	10.7	9.3	8.5	8.9	9.8	

Table 90 Generators' Spot Market Exposure - Luzon

	Year-on-Year Comparison of Generator's Monthly Spot Exposure - Luzon						
	Jan	Feb	Mar	Apr	May	Jun	Jul
2015 (%) Spot Exposure	7.6	8.0	11.2	11.9	9.9	10.3	11.5
2014 (%) Spot Exposure	11.3	12.7	10.4	9.7	8.1	9.2	10.4
Y-Y (%) Change	(3.7)	(4.6)	0.8	2.2	1.8	1.2	1.2
continuation...	Aug	Sep	Oct	Nov	Dec	Annual Avg	
2015 (%) Spot Exposure	10.2	10.7	9.3	8.5	8.9	9.8	
2014 (%) Spot Exposure	7.9	10.4	11.4	9.5	10.0	10.0	
Y-Y (%) Change	2.3	0.2	(2.1)	(1.1)	(1.1)	(0.2)	

Table 91 Year-on-Year Comparison of Generators' Spot Market Exposure - Luzon

Spot exposure of Visayas generators was posted at an average of 23.4 percent this year, higher than that of the Luzon region. Meanwhile, the monthly level of spot exposure in the region was maintained within the range of a low 19.5 percent in January to a high of 25.9 percent in both the February and March billing months. Year-on-year comparison showed an increase by 5.6 percent from the average spot exposure of Visayas generators, recorded at 17.8 percent in the previous year.

The total volume of energy transacted by Visayas generators was higher by 9.5 percent from last year's average volume of 786,422/MWh to 861,138/MWh in the current year, mainly influenced by the notable increase in the region's total metered quantities in the January and February billing months. Spot transactions were similarly higher by about 43.8 percent from an average spot volume of 140,198/MWh in 2014 to 201,603/MWh. It may be recalled that partial market suspension was declared by the ERC which affected the Visayas from January to March of the previous year, influencing the low spot transactions recorded when the Visayas market was still under market suspension. Bilateral contracting was higher by 2.1 percent in 2014 at 659,530/MWh than in the previous year's 664,224/MWh.

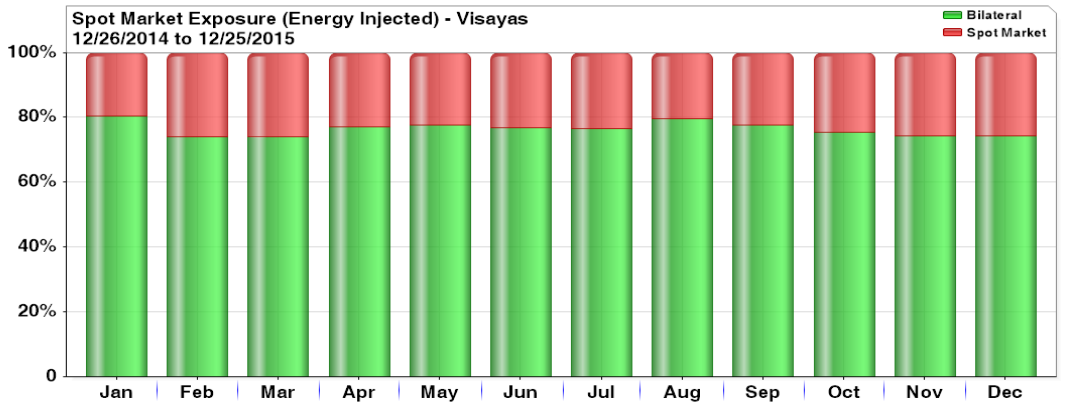

Figure 82 Visayas' Generators Spot Market Exposure

	Generator's Spot Exposure by Billing Month - Visayas, 2015						
	Jan	Feb	Mar	Apr	May	Jun	Jul
Metered Qty (MWh)	797,756	857,977	753,484	881,602	872975	887,358	887,478
Bilateral Qty (MWh)	642,227	636,106	558,033	680,197	679,108	682,611	680,559
Spot Market Qty (MWh)	155,529	221,871	195,451	201,404	193,867	204,747	206,918
Bilateral Qty (%)	80.5	74.1	74.1	77.2	77.8	76.9	76.7
Spot Market (%)	19.5	25.9	25.9	22.8	22.2	23.1	23.3
continuation...	Aug	Sep	Oct	Nov	Dec	Annual Avg	
Metered Qty (MWh)	872,892	874,152	878,199	900,937	868,791	861,133	
Bilateral Qty (MWh)	695,566	679,983	662,768	670,651	646,551	659,530	
Spot Market Qty (MWh)	177,326	194,169	215,431	230,286	222,240	201,603	
Bilateral Qty (%)	79.7	77.8	75.5	74.4	74.4	76.6	
Spot Market (%)	20.3	22.2	24.5	25.6	25.6	23.4	

Table 92 Generators' Spot Market Exposure - Visayas

	Year-on-Year Comparison of Generator's Monthly Spot Exposure - Visayas						
	Jan	Feb	Mar	Apr	May	Jun	Jul
2015 (%) Spot Exposure	19.5	25.9	25.9	22.8	22.2	23.1	23.3
2014 (%) Spot Exposure	1.8	15.1	24.0	20.6	23.3	23.2	21.2
Y-Y (%) Change	17.7	10.7	2.0	2.3	(1.0)	(0.1)	2.2
continuation...	Aug	Sep	Oct	Nov	Dec	Annual Avg	
2015 (%) Spot Exposure	20.3	22.2	24.5	25.6	25.6	23.4	
2014 (%) Spot Exposure	17.4	10.8	16.8	17.0	16.5	17.8	
Y-Y (%) Change	2.9	11.4	7.8	8.6	9.1	5.6	

Table 93 Year-on-Year Comparison of Generators' Spot Market Exposure - Visayas

CUSTOMER

The Customer's spot exposure is equivalent to the percentage of energy withdrawn not covered by bilateral contracts.

For billing year 2015, the spot market exposure of customers accounted for 9.8 percent of the total energy withdrawn while the majority or 90.2 percent was covered by bilateral contracts. Corresponding to the trend in the spot exposure of generators, customers' spot exposure were higher during the April billing month, averaging at 11.6 percent and also in March and July, both with 11.2 percent. In contrast, the spot exposure of WESM customers was lowest during the January billing month at only 7.3 percent.

The spot market exposure of customers was observed to have increased by 0.9 percent from the average spot exposure of 9 percent posted in the previous year.

In terms of the volume of spot transactions, an increase of 16.1 percent was posted this year from an average of 453,937/MWh in 2014 to 527,242/MWh. Likewise, bilateral contracting rose by about 5 percent this year from an average of 4,607,303/MWh in the previous year to 4,835,446/MWh. Meanwhile, the total metered quantity of WESM customers increased by 6 percent in the current year, from an average of 5,061,240/MWh to 5,362,688/MWh.

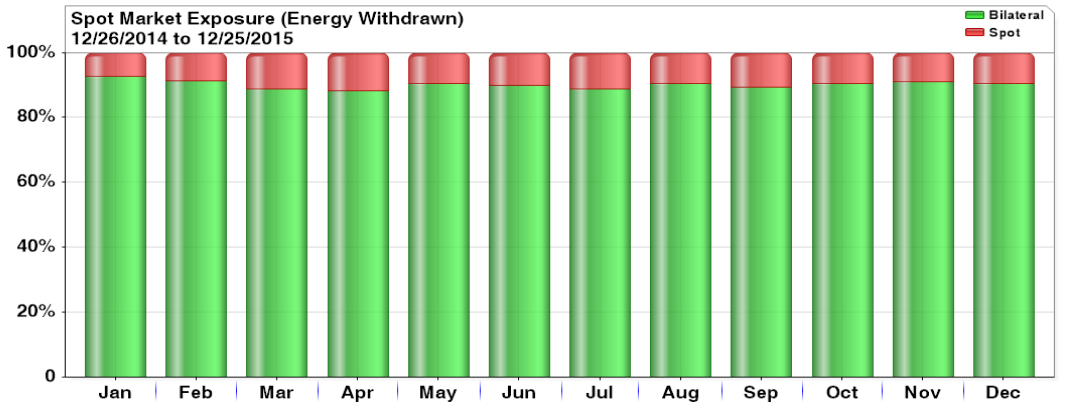

Figure 83 Customers' Spot Market Exposure - System

	Customer's Spot Exposure by Billing Month - 2015						
	Jan	Feb	Mar	Apr	May	Jun	Jul
Metered Qty (MWh)	4,554,629	4,922,836	4,694,205	5,413,680	5,672,785	5,920,217	5,411,247
Bilateral Qty (MWh)	4,222,346	4,498,807	4,167,551	4,786,512	5,129,029	5,328,603	4,803,784
Spot Market Qty (MWh)	332,283	424,029	526,654	627,168	543,756	591,614	607,464
Bilateral Qty (%)	92.4	91.4	88.8	88.4	90.4	90.0	88.8
Spot Market (%)	7.3	8.6	11.2	11.6	9.6	10.0	11.2

	Customer's Spot Exposure by Billing Month - 2015					
continuation...	Aug	Sep	Oct	Nov	Dec	Annual Avg
Metered Qty (MWh)	5,655,088	5,700,361	5,460,945	5,709,120	5,237,142	5,362,688
Bilateral Qty (MWh)	5,117,646	5,103,548	4,936,202	5,195,422	4,735,896	4,835,446
Spot Market Qty (MWh)	537,442	596,813	524,743	513,698	501,246	527,242
Bilateral Qty (%)	90.5	89.5	90.4	91.0	90.4	90.2
Spot Market (%)	9.5	10.5	9.6	9.0	9.6	9.8

Table 94 Customers' Spot Market Exposure - System

	Year-on-Year Comparison of Generator's Monthly Spot Exposure - System						
	Jan	Feb	Mar	Apr	May	Jun	Jul
2015 (%) Spot Exposure	7.3	8.6	11.2	11.6	9.6	10.0	11.2
2014 (%) Spot Exposure	7.9	10.8	10.5	9.3	7.9	9.0	10.0
Y-Y (%) Change	(0.6)	(2.1)	0.7	2.3	1.7	1.0	1.2
continuation...	Aug	Sep	Oct	Nov	Dec	Annual Avg	
2015 (%) Spot Exposure	9.5	10.5	9.6	9.0	9.6	9.8	
2014 (%) Spot Exposure	7.1	8.4	10.0	8.4	8.7	9.0	
Y-Y (%) Change	2.4	2.1	(0.4)	0.6	0.8	0.9	

Table 95 Year-on-Year Comparison of Customers' Spot Market Exposure - System

About 9.8 percent of the total energy requirement of Luzon customers was procured from the spot market while the majority or 90.2 percent was covered by bilateral contracts. Of the latter, 89.9 percent was entered into by customers with generators within the Luzon region and the remaining 0.4 percent was contracted by generators from the Visayas.

Customers in Luzon recorded the highest monthly spot exposure in April at 12.3 percent, July at 12.2 percent and March, at 10.8 percent. On the other hand, spot exposure among customers was recorded low in November at 7.7 percent, followed by the January and February billing months, at 8 percent and 8.7 percent, respectively.

Year-on-year comparison showed a slight 0.6 percent increase in the spot exposure of Luzon customers, from the 9.2 percent average spot exposure recorded in 2014. Meanwhile, the total energy withdrawn of Luzon customers rose by 5.8 percent this year at 4,608,863/MWh from last year's 4,357,616/MWh. The volume of bilateral contracting within Luzon and even with the Visayas both demonstrated increases, by 5.1 percent (from 3,938,622/MWh to 4,138,988/MWh) and 6.7 percent (from 402,368/MWh to 452128/MWh), respectively, when compared to the previous year. Similarly, spot transactions increased by 12.4 percent, from an average of 402,368/MWh to 452,128/MWh.

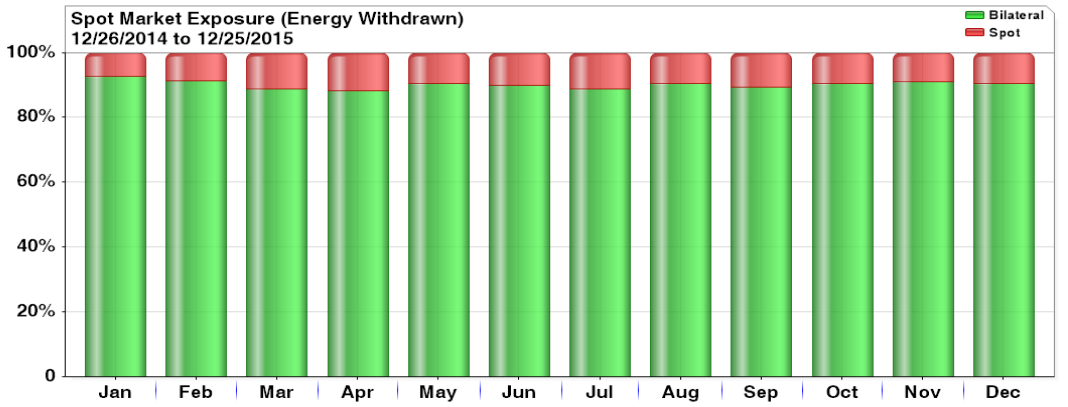

Figure 84 Luzon Customers' Spot Market Exposure

	Customer's Spot Exposure by Billing Month - Luzon, 2015						
	Jan	Feb	Mar	Apr	May	Jun	Jul
Metered Qty (MWh)	3,867,120	4,210,721	4,031,166	4,649,490	4,900,378	5,128,720	4,673,439
Bilateral Qty - Within Region (MWh)	3,543,009	3,832,366	3,582,829	4,066,480	4,415,639	4,604,497	4,087,821
Bilateral Qty - Other Region (MWh)	15,960	12,454	13,080	8,889	19,172	19,227	16,476
Spot Market Qty (MWh)	308,151	365,901	435,256	574,121	465,567	504,995	569,143
Bilateral Qty - Within Region (%)	91.6	91.0	88.9	87.5	90.1	89.8	87.5
Bilateral Qty - Other Region (%)	0.4	0.3	0.3	0.2	0.4	0.4	0.4
Spot Market (%)	8.0	8.7	10.8	12.3	9.5	9.8	12.2
continuation...	Aug	Sep	Oct	Nov	Dec	Annual Avg	
Metered Qty (MWh)	4,884,534	4,915,605	4,685,302	4,879,951	4,479,927	4,608,863	
Bilateral Qty - Within Region (MWh)	4,381,379	4,384,173	4,236,743	4,481,727	4,051,192	4,138,988	
Bilateral Qty - Other Region (MWh)	14,160	23,011	32,136	23,443	14,955	17,747	
Spot Market Qty (MWh)	488,995	508,421	416,422	374,781	413,780	452,128	
Bilateral Qty - Within Region (%)	89.7	89.2	90.4	91.8	90.4	89.8	
Bilateral Qty - Other Region (%)	0.3	0.5	0.7	0.5	0.3	0.4	
Spot Market (%)	10.0	10.3	8.9	7.7	9.2	9.8	

Table 96 Customers' Spot Market Exposure - Luzon

	Year-on-Year Comparison of Customer's Monthly Spot Exposure - Luzon						
	Jan	Feb	Mar	Apr	May	Jun	Jul
2015 (%) Spot Exposure	8.0	8.7	10.8	12.3	9.5	9.8	12.2
2014 (%) Spot Exposure	8.6	11.4	11.1	10.1	7.9	8.9	10.6
Y-Y (%) Change	(0.6)	(2.7)	(0.3)	2.3	1.6	0.9	1.6
continuation...	Aug	Sep	Oct	Nov	Dec	Annual Avg	
2015 (%) Spot Exposure	10.0	10.3	8.9	7.7	9.2	9.8	
2014 (%) Spot Exposure	7.0	8.6	10.2	8.2	9.6	9.2	
Y-Y (%) Change	3.0	1.8	(1.3)	(0.6)	(0.4)	0.6	

Table 97 Year-on-Year Comparison of Customers' Spot Market Exposure - Luzon

In the Visayas, 10 percent of the total energy withdrawn by customers was sourced from the spot market. On the other hand, about 85.1 percent was procured through bilateral contracting within the region while the rest of the 4.9 percent was covered by bilateral contracts with generators from Luzon.

Monthly spot exposure among the Visayas customers was highest during the March, October and November billing months at 13.8 percent, 14 percent and 16.8 percent, and was lowest in January at 3.5 percent. Low spot exposure among the Visayas customers were likewise observed in July at 5.2 percent, August 6.3 percent and April at 6.9 percent.

In terms of total metered quantities, Visayas customers increased their total energy withdrawn by about 7.1 percent this year at 753,825/MWh from last year's 703,625/MWh. Meanwhile, the volume of bilateral contracting within the region increased by 1.9 percent from last year's 629,598/MWh to 641,783/MWh while the volume of bilateral contracting with Luzon notably rose by 64.4 percent to 36,927/MWh from 22,458/MWh. The volume of spot transactions in the Visayas similarly grew by 45.7 percent, from 51,569/MWh to 75,115/MWh.

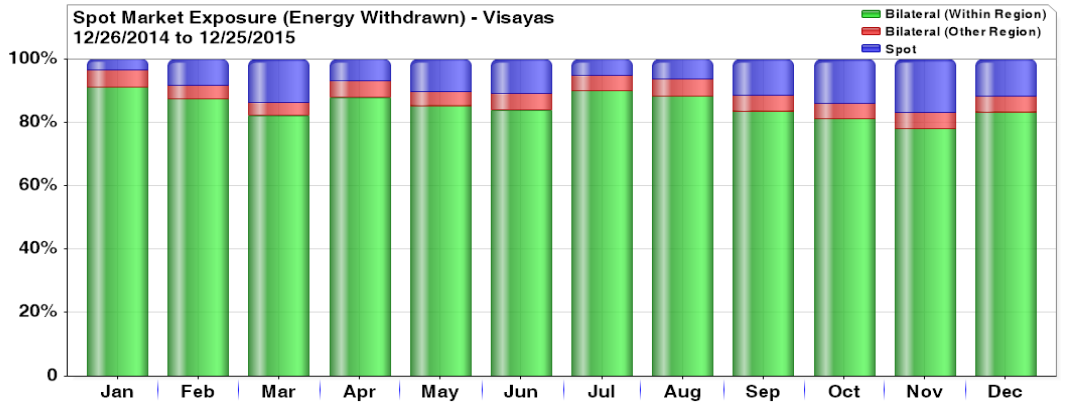

Figure 85 Visayas Customers' Spot Market Exposure

	Customer's Spot Exposure by Billing Month - Visayas, 2015						
	Jan	Feb	Mar	Apr	May	Jun	Jul
Metered Qty (MWh)	687,509	712,115	663,039	764,190	772,407	791,497	737,808
Bilateral Qty - Within Region (MWh)	626,267	623,652	544,953	671,309	659,936	663,384	664,084
Bilateral Qty - Other Region (MWh)	37,110	30,335	26,689	39,834	34,282	41,495	35,403
Spot Market Qty (MWh)	24,132	58,128	91,398	53,047	78,189	86,618	38,321
Bilateral Qty - Within Region (%)	91.1	87.6	82.2	87.8	85.4	83.8	90.0
Bilateral Qty - Other Region (%)	5.4	4.3	4.0	5.2	4.4	5.2	4.8
Spot Market (%)	3.5	8.2	13.8	6.9	10.1	10.9	5.2
continuation...	Aug	Sep	Oct	Nov	Dec	Annual Avg	
Metered Qty (MWh)	770,554	784,756	775,643	829,169	757,215	753,825	
Bilateral Qty - Within Region (MWh)	681,406	656,972	630,631	647,208	631,596	641,783	
Bilateral Qty - Other Region (MWh)	40,702	39,392	36,691	43,044	38,152	36,927	
Spot Market Qty (MWh)	48,447	88,391	108,321	138,917	87,466	75,115	
Bilateral Qty - Within Region (%)	88.4	83.7	81.3	78.1	83.4	85.1	
Bilateral Qty - Other Region (%)	5.3	5.0	4.7	5.2	5.0	4.9	
Spot Market (%)	6.3	11.3	14.0	16.8	11.6	10.0	

Table 98 Customers' Spot Market Exposure - Visayas

	Year-on-Year Comparison of Customer's Monthly Spot Exposure - Visayas						
	Jan	Feb	Mar	Apr	May	Jun	Jul
2015 (%) Spot Exposure	3.5	8.2	13.8	6.9	10.1	10.9	5.2
2014 (%) Spot Exposure	3.2	6.6	6.9	3.9	8.1	9.8	6.6
Y-Y (%) Change	0.3	1.6	6.9	3.1	2.0	1.2	(1.4)
continuation...	Aug	Sep	Oct	Nov	Dec	Annual Avg	
2015 (%) Spot Exposure	6.3	11.3	14.0	16.8	11.6	10.0	
2014 (%) Spot Exposure	7.5	6.9	9.0	9.4	8.6	7.3	
Y-Y (%) Change	(1.3)	4.3	5.0	7.3	2.9	2.6	

Table 99 Year-on-Year Comparison of Customers' Spot Market Exposure - Visayas

MARKET CONCENTRATION

The market concentration indices measure the concentration of a market to assess if existing conditions facilitate or impede the development of competition. The less concentrated the market, the greater the possibility of effective competition.

The market share index, from which the Herfindahl-Hirschman Index (HHI) is computed, measures the percentage of energy or capacity that a Trading Participant controls in the monitored market. For this Report, calculation of market share was based on three major groupings: (i) by major participants; (ii) by trading participants; and (iii) by generating plants.

MARKET SHARE

By Major Participant

Similar to the previous year, the market remained dominated by four major participant groups which combined market share accounted for 63.5 percent of the total WESM registered capacity for billing year 2015. San Miguel Corporation (SMC) retained the top spot with the biggest share of the market this year at an average of 20.3 percent, followed by Aboitiz Power (AP) with 15.8 percent, First Gen Corporation (FGC) with 15.1 percent and Power Sector Assets and Liabilities Management Corporation (PSALM) with 13.7 percent.

Increase in the market share of SMC was observed this year from last year's average of 20.1 percent, in part attributed to the inclusion of the 218 MW generating units of hydro plant Angat in its share of WESM registered capacity. Increase in the registered capacity of hydro plant San Roque from an aggregate of 411 MW to 435 MW was likewise observed this year, augmenting the total capacity attributed to San Miguel by an additional 24 MW.

On the other hand, the Aboitiz group registered a decline in its market share of 16.8 percent in the previous year while FGC only posted a minimal increase from its market share of 15 percent in 2014. These were despite the entry of additional capacity from hydro plant Sabangan (14.3 MW), and the capacity increase of hydro plant Binga from 132 MW to 140 MW, both of which were attributed to AP. Increase in the market share of FGC on the other hand, were influenced by the entry of natural gas plant Avion (97 MW) and solar plant Burgos (3.7 MW) which were added to the total capacity of FGC this year. PSALM, for its part recorded a steady decline in its market share this year, from 14.2 percent in January to 13.3 percent in December.

This declining trend in the market share of the dominant groups in the market was observed to be influenced by the entry of 21 new generating units with a combined registered capacity of about 984 MW, most of which were affiliated or owned by new participant groups.

Semirara Mining and Power Corporation (SMPC) posted an increase in its market share from 4.5 percent in 2014 to 6 percent in the current year, on account of the entry of the 2x150MW coal plant SLPGC, on top of the 2x330MW coal plant Calaca under its portfolio. Trans-Asia Oil and Energy Development Corporation (TAOEDC) similarly recorded an increase in its market share from 0.9 percent in 2014 to 2.0 percent this year, credited to the entry of the additional 135 MW unit of coal plant SLTEC as well as the transfer of ownership of the 110 MW oil-based plant Subic from Udenna Management Resource Corporation (UMRC) to One Subic Power Generation Corporation (OSPGC) effective 17 December.

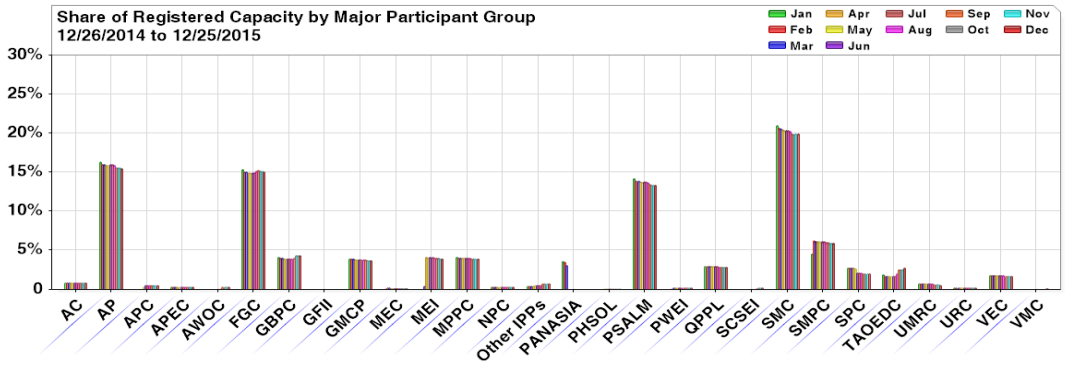

Figure 86 Share of Registered Capacity by Major Participant

SMC's share of the market based on offered capacity was highest at an average of 23.4 percent this year, followed by FGC at 20.5 percent and AP at 15.2 percent. PSALM distantly followed at 6.3 percent and Masinloc Power Partners Corporation (MPPC) at 6.0 percent. Sharp reduction in the market share of PSALM in terms of offered capacity compared with its share of the market based on registered capacity was observed in view of the designation of PSALM-controlled Malaya plant as a must-run-unit effective 23 February 2014[31]. Thus, the 650 MW Malaya plant no longer submits capacity offers in the WESM.

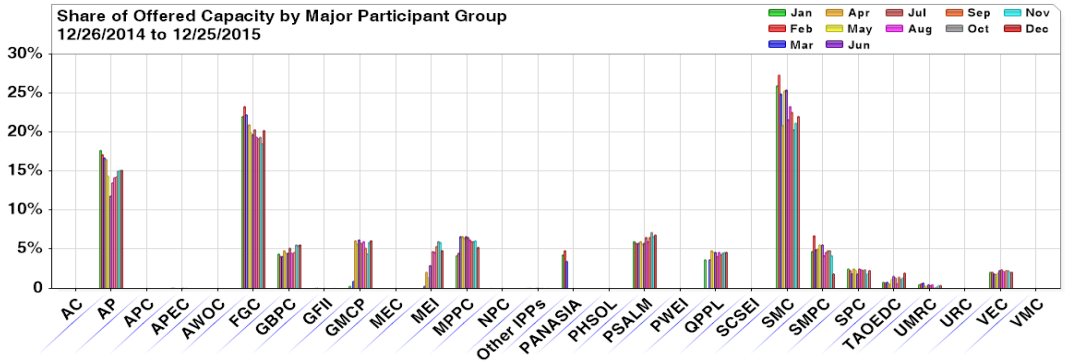

Figure 87 Share of Offered Capacity by Major Participant

The market was likewise dominated by the top four major groups in terms of actual generation, accounting for a combined share of about 68.5 percent. The same indicates that majority of the demand requirement during the course of billing year 2015 was supplied by SMC, FGC, AP and PSALM, with their percentages share of the market at 24 percent, 22.9 percent, 14 percent, and 7.6 percent, respectively. MPPC came next at 6.4 percent, SMPC at 6 percent, GMCP at 4.6 percent, QPPL at 4.4 percent and Global Business Power Corporation (GBPC) at 3.7 percent.

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SMC recorded lower market share levels during the last quarter of the year, following the high level of outage capacity recorded by major coal plant Sual during these months.

Similar to the previous year, PSALM held the top place in terms of percentage share of spot transactions at an average of 26.5 percent this year, followed by SMC at 19 percent, FGC at 12.9 percent and AP at 12 percent. TAOEDC followed distantly at 3.9 percent, GMCP at 3.2 percent, MPPC at 2.7 percent and Ayala Corporation (AC) at 2.4 percent.

Drop in the market share of SMC was observed during the last quarter of the year. On the other hand, AP recorded higher share of the market during the first quarter.

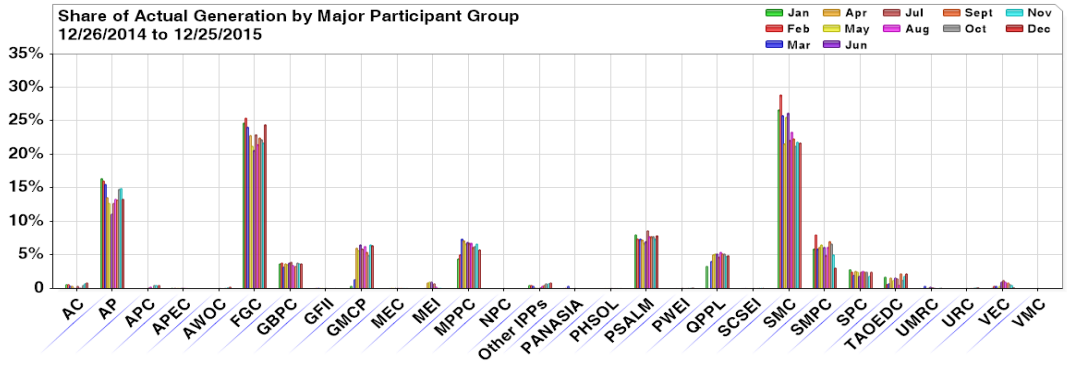

Figure 88 Share of Actual Generation by Major Participant

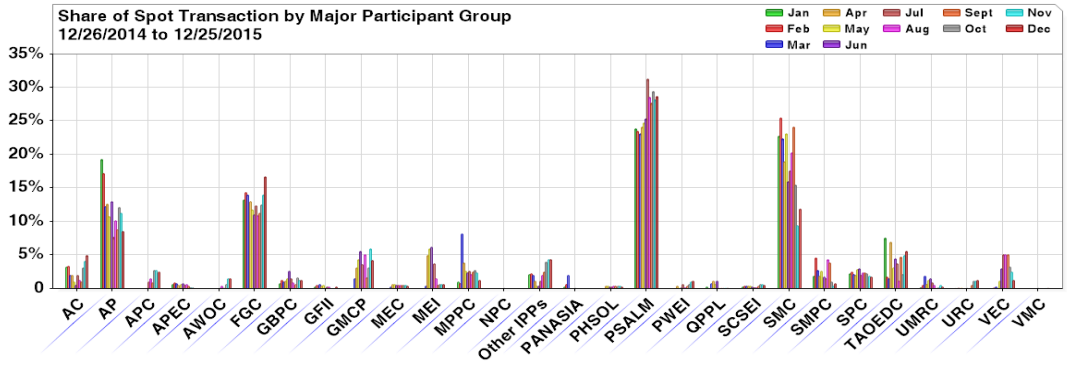

Figure 89 Share of Spot Transaction by Major Participant

By Trading Participant

PSALM had the biggest market share of registered capacity by trading participant, averaging at about 13.7 percent, distantly followed by San Miguel Energy Corporation (SMEC) with an 8.2 percent share of the market; South Premiere Power Corporation (SPPC) with 7.6 percent, FGP Corporation (FGPCSTRA) at 6.1 percent and Therma Luzon Inc. with 4.9 percent. Note that SMEC is the registered trading participant for major coal plant Sual while SPPC trades in the market for natural gas plant Ilijan. FGPCSTRA and TLI, on the other hand, are the trading participants for the Sta. Rita natural gas plants and major coal plant Pagbilao, respectively.

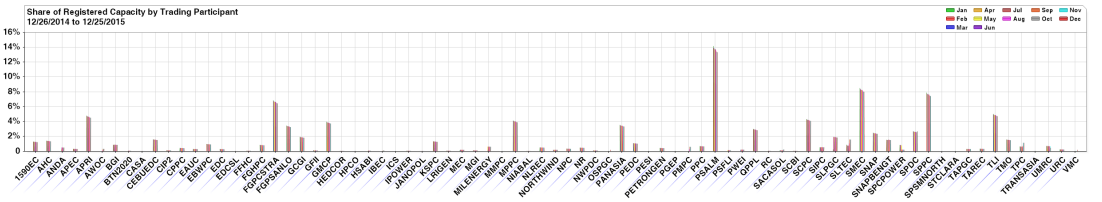

Figure 90 Share of Registered Capacity by Trading Participant

By Generating Plant

Generating plants owned or controlled by the top four major groups likewise dominated the market share by generating plant based on registered capacity. Large generating coal plant Sual held the top spot at 8.2 percent followed by natural gas plants Ilijan and Sta. Rita with an average share of 7.6 percent and 6.6 percent, major coal plant Pagbilao at 4.9 percent, hydro plant Kalayaan with 4.6 percent, major coal plant Calaca with 4.2 percent, oil-based plant Malaya with 4.1 percent, major coal plants Masinloc and Mariveles with 4 percent and 3.8 percent, respectively, oil-based plant Limay with 3.4 percent, geothermal plant Leyte A with 3.4 percent and natural gas plant San Lorenzo with 3.3 percent.

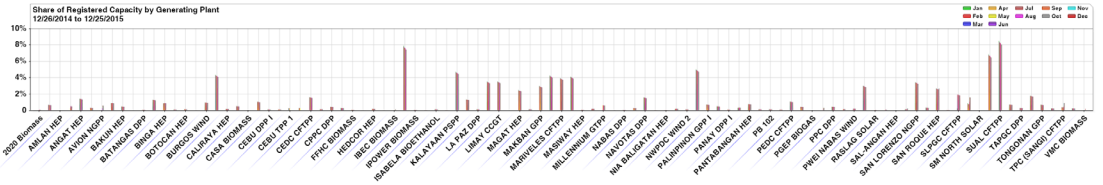

Figure 91 Share of Registered Capacity by Generating Plant

HERFINDAHL-HIRSCHMAN INDEX (HHI)

The HHI measures the degree of market concentration that takes into account the relative size and distribution of participants in the market. Defined as the sum of squares of the participant's market share, the HHI approaches zero when the market has very large number of participants with each having a relatively small market share. In contrary, the HHI increases as the number of participants in the market decreases, and the disparity in the market shares among the participants increases. The following are the widely-used HHI screening numbers: (1) when HHI is less than 1,000 the market is not concentrated; (2) in the range of 1,000 to 1,800 the market is moderately concentrated; (3) greater than 1,800 but less than 2,500 the market is concentrated; and (4) greater than 2,500 the market is highly concentrated and signals lack of competition in the market.

The Figures below show the monthly HHI calculated based on the following: WESM registered capacity, registered capacity net of outage, offered capacity, metered quantity and spot transaction. The HHI, when based on registered capacity, provides the base scenario in assessing market concentration which does not vary over time unless there are significant changes in the ownership and registered capacity of the generators, or registration and deregistration of generators.

Calculated by major participant grouping, the resulting HHI for the year indicated that in general, the market is moderately concentrated. Based on actual generation, however, it is observed

that the HHI during the February billing month hit the concentrated mark, attributable to the decline in the actual generation of major coal plants Masinloc, GN Power, QPPL and SLTEC and the corresponding increase in the market share of dominant groups SMC and FGC. Note that outage capacity was highest during the February billing month.

Grouping by trading participant indicated that the market is generally not concentrated, except if based on spot transaction, which resulting HHI pointed to a not concentrated to moderately concentrated market, particularly during the second half of the billing year.

By generating plant, the resulting HHI signalled a not concentrated market throughout the billing year.

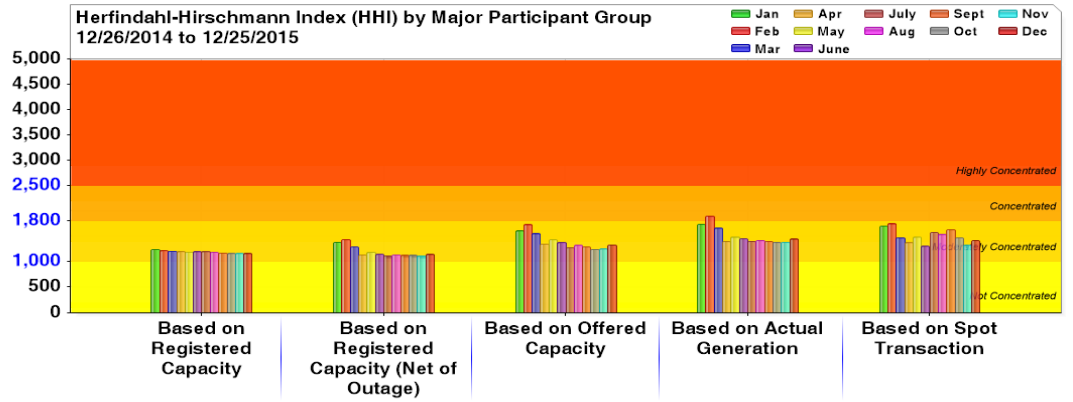

Figure 92 HHI by Major Participant

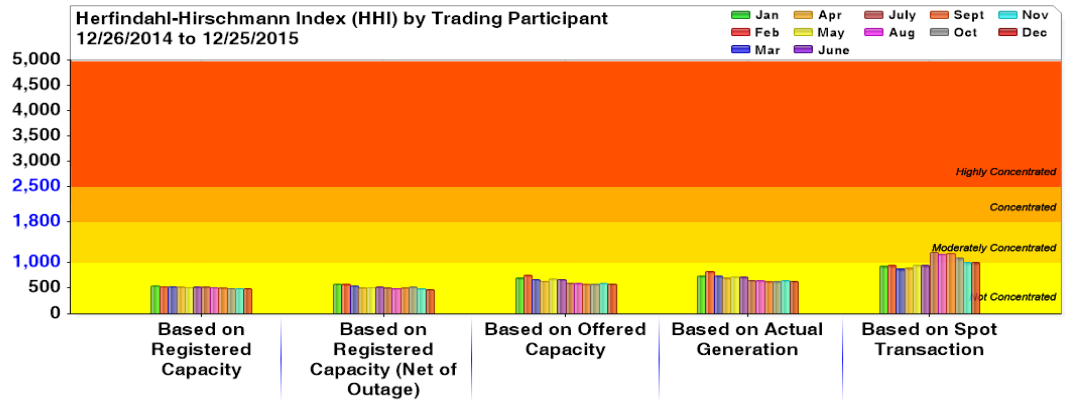

Figure 93 HHI by Participant

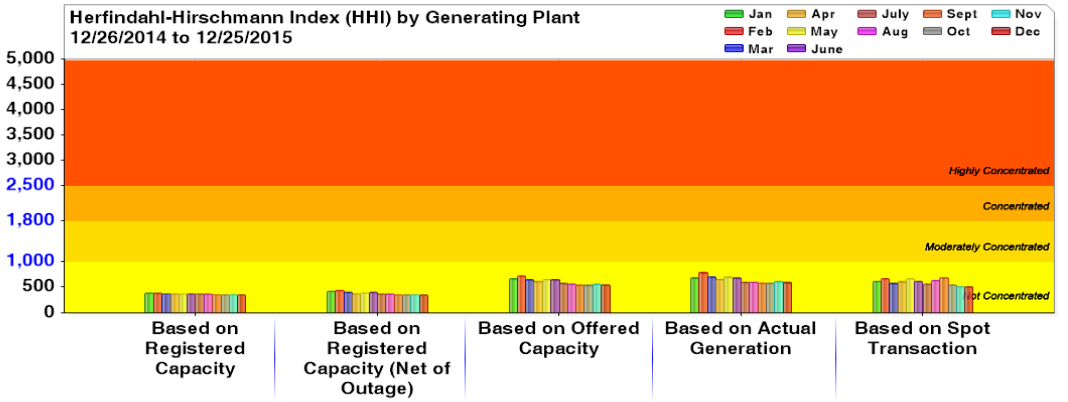

Figure 94 HHI by Plant

APPENDIX 'A'

List of WESM Registered Capacities as of 25 December 2015 - Luzon

WESM REGISTERED CAPACITY LIST					
Market Participant Name	Region	MT Node	Type	Classification	Registered Maximum Capacity (Pmax, MW)
1590 Energy Corporation	Luzon	1BAUANG_G01	Oil-Based	Scheduled	200.00
Alternergy Wind One Corporation	Luzon	3AWOC_G01	Wind	Non-scheduled NRE	54.00
Anda Power Corporation	Luzon	1ANDA_G01	Coal	Scheduled	82.00
Angat Hydropower Corporation	Luzon	1ANGAT_A	Hydro	Scheduled	18.00
Angat Hydropower Corporation	Luzon	1ANGAT_M	Hydro	Scheduled	200.00
AP Renewables Inc.	Luzon	3MKBN_A	Geothermal	Scheduled	126.00
AP Renewables Inc.	Luzon	3MKBN_B	Geothermal	Scheduled	126.00
AP Renewables Inc.	Luzon	3MKBN_C	Geothermal	Scheduled	110.00
AP Renewables Inc.	Luzon	3MKBN_D	Geothermal	Scheduled	40.00
AP Renewables Inc.	Luzon	3MKBN_E	Geothermal	Scheduled	40.00
AP Renewables Inc.	Luzon	3ORMAT_G01	Geothermal	Scheduled	12.00
AP Renewables Inc.	Luzon	3TIWI_A	Geothermal	Scheduled	118.00
AP Renewables Inc.	Luzon	3TIWI_B	Geothermal	Scheduled	43.70
AP Renewables Inc.	Luzon	3TIWI_C	Geothermal	Scheduled	114.00
Asia Pacific Energy Corporation	Luzon	1APEC_G01	Coal	Scheduled	52.00
Bac-Man Geothermal Inc.	Luzon	3BACMAN_G01	Geothermal	Scheduled	120.00
Bac-Man Geothermal Inc.	Luzon	3BACMAN_G02	Geothermal	Scheduled	20.00
Bataan 2020, Inc.	Luzon	1BT2020_G01	Biomass	Non-scheduled NRE	13.00
CIP II Power Corporation	Luzon	1CIP2_G01	Oil-Based	Scheduled	21.27
Energy Development Corporation (additional facility)	Luzon	1BURGOS_G02	Solar	Non-scheduled NRE	3.70
EDC Burgos Wind Power Corporation	Luzon	1BURGOS_G01	Wind	Non-scheduled NRE	150.00
First Gen Hydro Power Corporation	Luzon	1MASIWA_G01	Hydro	Scheduled	12.40
First Gen Hydro Power Corporation	Luzon	1PNTBNG_U01	Hydro	Scheduled	60.00
First Gen Hydro Power Corporation	Luzon	1PNTBNG_U02	Hydro	Scheduled	60.00
FGP Corporation (San Lorenzo)	Luzon	3STA-RI_G05	Natural Gas	Scheduled	264.80
FGP Corporation (San Lorenzo)	Luzon	3STA-RI_G06	Natural Gas	Scheduled	261.80
First Gas Power Corporation (Sta Rita)	Luzon	3STA-RI_G01	Natural Gas	Scheduled	257.30
First Gas Power Corporation (Sta Rita)	Luzon	3STA-RI_G02	Natural Gas	Scheduled	255.70
First Gas Power Corporation (Sta Rita)	Luzon	3STA-RI_G03	Natural Gas	Scheduled	265.50

WESM REGISTERED CAPACITY LIST					
Market Participant Name	Region	MT Node	Type	Classification	Registered Maximum Capacity (Pmax, MW)
First Gas Power Corporation (Sta Rita)	Luzon	3STA-RI_G04	Natural Gas	Scheduled	264.00
GNPower Mariveles Coal Plant Ltd. Co.	Luzon	1MARVEL_G01	Coal	Scheduled	302.00
GNPower Mariveles Coal Plant Ltd. Co.	Luzon	1MARVEL_G02	Coal	Scheduled	302.00
Green Future Innovations, Inc.	Luzon	1GFII_G01	Biomass	Scheduled	19.81
HEDCOR, Inc.	Luzon	1SLANGN_G01	Hydro	Non-scheduled NRE	2.40
HEDCOR, Inc.	Luzon	1NMHC_G01	Hydro	Non-scheduled NRE	5.09
Hedcor Sabangan, Inc.	Luzon	1SABANG_G01	Hydro	Non-scheduled NRE	14.30
Isabela Biomass Energy Corporation	Luzon	1IBEC_G01	Biomass	Non-scheduled NRE	18.00
Lafarge Republic, Inc.	Luzon	3LAFARG_G01	Oil-Based	Scheduled	6.35
Lafarge Republic, Inc.	Luzon	3LAFARG_G02	Oil-Based	Scheduled	6.35
Maibarara Geothermal, Inc.	Luzon	3MGPP_G01	Geothermal	Scheduled	20.00
Majestics Energy Corporation	Luzon	3MEC_G01	Solar	Non-scheduled NRE	32.90
Masinloc Power Partners Co. Ltd.	Luzon	1MSINLO_G01	Coal	Scheduled	315.00
Masinloc Power Partners Co. Ltd.	Luzon	1MSINLO_G02	Coal	Scheduled	315.00
Millennium Energy, Inc.	Luzon	2MGTPP_G01	Oil-Based	Scheduled	100.00
Montalban Methane Power Corp.	Luzon	2MMPP_G01	Biomass	Non-scheduled NRE	5.10
National Irrigation Administration	Luzon	1NIABAL_G01	Hydro	Non-scheduled	6.00
North Luzon Renewable Energy Corporation	Luzon	1CAPRIS_G01	Wind	Non-scheduled NRE	81.00
North Wind Power Development Corporation	Luzon	1NWIND_G01	Wind	Non-scheduled NRE	33.00
North Wind Power Development Corporation	Luzon	1NWIND_G02	Wind	Non-scheduled NRE	18.90
Panasia Energy, Inc.	Luzon	1LIMAY_A	Oil-Based	Scheduled	270.00
Panasia Energy, Inc.	Luzon	1LIMAY_B	Oil-Based	Scheduled	270.00
Pangea Green Energy Philippines, Inc.	Luzon	2PNGEA_G01	Biomass	Non-scheduled NRE	0.80
People's Energy Services Inc.	Luzon	3BART_G01	Hydro	Non-scheduled NRE	1.80
Petron Corporation	Luzon	1PETRON_G01	Coal	Scheduled	70.00
Prime Meridian PowerGen Corporation	Luzon	3AVION_G01	Natural Gas	Scheduled	97.00
PSALM Corporation	Luzon	1CASECN_G01	Hydro	Scheduled	165.00
PSALM Corporation	Luzon	1HEDCOR_G01	Hydro	Scheduled	30.00
PSALM Corporation	Luzon	3BOTOCA_G01	Hydro	Scheduled	20.80
PSALM Corporation	Luzon	3CALIRY_G01	Hydro	Scheduled	28.00
PSALM Corporation	Luzon	3KAL_G01	Hydro	Scheduled	180.00

WESM REGISTERED CAPACITY LIST					
Market Participant Name	Region	MT Node	Type	Classification	Registered Maximum Capacity (Pmax, MW)
PSALM Corporation	Luzon	3KAL_G02	Hydro	Scheduled	180.00
PSALM Corporation	Luzon	3KAL_G03	Hydro	Scheduled	180.00
PSALM Corporation	Luzon	3KAL_G04	Hydro	Scheduled	180.00
PSALM Corporation	Luzon	3MALAYA_G01	Oil-Based	Scheduled	300.00
PSALM Corporation	Luzon	3MALAYA_G02	Oil-Based	Scheduled	350.00
Quezon Power (Philippines) Ltd. Co.	Luzon	3QPPL_G01	Coal	Scheduled	459.00
RASLAG Corp.	Luzon	1RASLAG_G01	Solar	Non-scheduled NRE	9.00
San Jose City I Power Corporation	Luzon	1IPOWER_G01	Biomass	Non-scheduled NRE	10.80
San Miguel Energy Corporation	Luzon	1SUAL_G01	Coal	Scheduled	647.00
San Miguel Energy Corporation	Luzon	1SUAL_G02	Coal	Scheduled	647.00
SEM-Calaca Power Corporation	Luzon	3CALACA_G01	Coal	Scheduled	330.00
SEM-Calaca Power Corporation	Luzon	3CALACA_G02	Coal	Scheduled	330.00
SN Aboitiz Power - Benguet, Inc.	Luzon	1BINGA_U01	Hydro	Scheduled	35.00
SN Aboitiz Power - Benguet, Inc.	Luzon	1BINGA_U02	Hydro	Scheduled	35.00
SN Aboitiz Power - Benguet, Inc.	Luzon	1BINGA_U03	Hydro	Scheduled	35.00
SN Aboitiz Power - Benguet, Inc.	Luzon	1BINGA_U04	Hydro	Scheduled	35.00
SN Aboitiz Power - Benguet, Inc.	Luzon	1AMBUK_U01	Hydro	Scheduled	35.00
SN Aboitiz Power - Benguet, Inc.	Luzon	1AMBUK_U02	Hydro	Scheduled	35.00
SN Aboitiz Power - Benguet, Inc.	Luzon	1AMBUK_U03	Hydro	Scheduled	35.00
SN Aboitiz Power - Magat, Inc.	Luzon	1MAGAT_U01	Hydro	Scheduled	95.00
SN Aboitiz Power - Magat, Inc.	Luzon	1MAGAT_U02	Hydro	Scheduled	95.00
SN Aboitiz Power - Magat, Inc.	Luzon	1MAGAT_U03	Hydro	Scheduled	95.00
SN Aboitiz Power - Magat, Inc.	Luzon	1MAGAT_U04	Hydro	Scheduled	95.00
Solar Philippines Commercial Rooftop Projects, Inc.	Luzon	2SMNRTH_G01	Solar	Non-scheduled NRE	1.22
South Luzon Thermal Energy Corporation	Luzon	3SLTEC_G01	Coal	Scheduled	120.60
South Luzon Thermal Energy Corporation	Luzon	3SLTEC_G02	Coal	Scheduled	135.00
South Premiere Power Corporation	Luzon	3ILIJAN_G01	Natural Gas	Scheduled	600.00
South Premiere Power Corporation	Luzon	3ILIJAN_G02	Natural Gas	Scheduled	600.00
Southwest Luzon Power Generation Corporation	Luzon	3SLPGC_G01	Coal	Scheduled	150.00
Southwest Luzon Power Generation Corporation	Luzon	3SLPGC_G02	Coal	Scheduled	150.00
Strategic Power Development Corporation	Luzon	1SROQUE_U01	Hydro	Scheduled	145.00
Strategic Power Development Corporation	Luzon	1SROQUE_U02	Hydro	Scheduled	145.00

WESM REGISTERED CAPACITY LIST					
Market Participant Name	Region	MT Node	Type	Classification	Registered Maximum Capacity (Pmax, MW)
Strategic Power Development Corporation	Luzon	1SROQUE_U03	Hydro	Scheduled	145.00
Therma Luzon, Inc.	Luzon	3PAGBIL_G01	Coal	Scheduled	382.00
Therma Luzon, Inc.	Luzon	3PAGBIL_G02	Coal	Scheduled	382.00
Therma Mobile, Inc.	Luzon	2TMO_G01	Oil-Based	Scheduled	66.00
Therma Mobile, Inc.	Luzon	2TMO_G02	Oil-Based	Scheduled	67.20
Therma Mobile, Inc.	Luzon	2TMO_G03	Oil-Based	Scheduled	57.00
Therma Mobile, Inc.	Luzon	2TMO_G04	Oil-Based	Scheduled	52.00
Trans-Asia Power Generation Corporation	Luzon	1T_ASIA_G01	Oil-Based	Scheduled	50.00
Udenna Management Resource Corporation	Luzon	1S_ENRO_G01	Oil-Based	Scheduled	110.00
Vivant Sta. Clara Northern Renewables Generation Corporation	Luzon	1BAKUN_G01	Hydro	Scheduled	76.00

APPENDIX 'B'

List of WESM Registered Capacities as of 25 December 2015 - Visayas

WESM REGISTERED CAPACITY LIST					
Market Participant Name	Region	MT Node	Type	Classification	Registered Maximum Capacity (Pmax, MW)
Bohol I Electric Cooperative, Inc.	Visayas	7JANOPO_G01	Hydro	Non-scheduled NRE	5.00
Cebu Energy Development Corporation	Visayas	5CEDC_G01	Coal	Scheduled	246.00
Cebu Private Power Corporation	Visayas	5CPPC_G01	Oil-Based	Scheduled	70.00
Central Azucarera de San Antonio	Visayas	8CASA_G01	Biomass	Non-scheduled	4.00
East Asia Utilities Corporation	Visayas	5EAUC_G01	Oil-Based	Scheduled	49.60
Energy Development Corporation	Visayas	6NASULO_G01	Geothermal	Scheduled	47.50
First Farmers Holdings Corporation	Visayas	6FFHC_G01	Biomass	Non-scheduled	12.00
Green Core Geothermal Inc.	Visayas	6PAL1A_G01	Geothermal	Scheduled	109.57
Green Core Geothermal Inc.	Visayas	6PAL2A_G01	Geothermal	Scheduled	79.16
Green Core Geothermal Inc.	Visayas	4LGPP_G01	Geothermal	Scheduled	107.00
Hawaiian-Philippine Company	Visayas	6HPCO_G01	Biomass	Non-scheduled NRE	3.00
ICS Renewables	Visayas	6AMLA_G01	Hydro	Non-scheduled NRE	0.90
KEPCO Salcon Power Corporation	Visayas	5KSPC_G01	Coal	Scheduled	103.00
KEPCO Salcon Power Corporation	Visayas	5KSPC_G02	Coal	Scheduled	103.00
National Power Corporation (PB 101)	Visayas	8STBAR_PB	Oil-Based	Scheduled	20.00
National Power Corporation (PB 102)	Visayas	8STBAR_PB2	Oil-Based	Scheduled	20.00
National Power Corporation (PB 103)	Visayas	8PANIT_PB	Oil-Based	Scheduled	15.00
Panay Energy Development Corporation	Visayas	8PEDC_G01	Coal	Scheduled	167.40
Panay Power Corporation	Visayas	8GLOBAL_G01	Oil-Based	Scheduled	10.00
Panay Power Corporation	Visayas	8PPC_G01	Oil-Based	Scheduled	72.00
Panay Power Corporation	Visayas	8AVON_G01	Oil-Based	Scheduled	20.00
PetroWind Energy Inc.	Visayas	8PWIND_G01	Wind	Non-scheduled NRE	36.00
Phil. Solar Farm - Leyte, Inc.	Visayas	4PHSOL_G01	Solar	Non-scheduled NRE	24.48
PSALM Corporation	Visayas	4LEYTE_A	Geothermal	Scheduled	538.00
San Carlos Bioenergy, Inc.	Visayas	6SCBE_G01	Biomass	Non-scheduled	8.30
San Carlos Solar Energy, Inc.	Visayas	6SACASL_G01	Solar	Non-scheduled NRE	19.80

WESM REGISTERED CAPACITY LIST					
Market Participant Name	Region	MT Node	Type	Classification	Registered Maximum Capacity (Pmax, MW)
San Carlos Solar Energy, Inc.	Visayas	6SACASL_G02	Solar	Non-scheduled NRE	19.80
SPC Island Power Corporation	Visayas	7BDPP_G01	Oil-Based	Scheduled	16.20
SPC Island Power Corporation	Visayas	8PDPP_G01	Oil-Based	Scheduled	15.00
SPC Island Power Corporation	Visayas	8PDPP3_G01	Oil-Based	Scheduled	57.00
SPC Power Corporation	Visayas	5CDPPI_G01	Oil-Based	Scheduled	18.00
SPC Power Corporation	Visayas	5CDPPI_G02	Oil-Based	Scheduled	18.00
Sta Clara Power Corporation	Visayas	7LOBOC_G01	Hydro	Non-scheduled NRE	1.20
Toledo Power Company	Visayas	5TPC_G01	Oil-Based	Scheduled	40.00
Toledo Power Company	Visayas	5TPC_G02	Coal	Scheduled	145.00
Trans-Asia Oil and Energy Development Corporation	Visayas	8GUIM_G01	Oil-Based	Non-scheduled	3.00
Trans-Asia Renewable Energy Corporation	Visayas	8SLWIND_G01	Wind	Non-scheduled NRE	54.00
Universal Robina Corporation	Visayas	6URC_G01	Biomass	Non-scheduled NRE	40.00
Victorias Milling Company,Inc.	Visayas	6VMC_G01	Biomass	Non-scheduled NRE	34.00

APPENDIX 'C'

Summary of Generator Trading Intervals[32] with Capacity Gap - Luzon
26 December 2014 to 25 December 2015

	Generator Trading Intervals with Capacity Gap, Luzon - 2015					
Resource Type	Generating plant outage	Equipment-related concer	Water elevation / availability	NIA IDR	Steam supply	Generator / Equipment test
BIOFUEL	-	-	-	-	-	-
COAL	1,403	3,988	-	-	29	395
GEO	656	4,238	-	-	45,071	23
HYDRO	39	281	32,997	19,678	-	337
NATGAS	9	39	-	-	-	14
OIL	2,246	44,243	-	-	2	675
Grand Total	4,353	52,789	32,997	19,678	45,102	1,444
continuation...	Ambient Conditions	Line Limitation	Coal Quality	Fuel oil operation	Star-up profile	Shutdown profile
BIOFUEL	-	-	-	-	-	-
COAL	-	56	6,551	10	165	794

32 Total generator resource trading-intervals in Luzon – calculated as the number of registered generator resource nodes multiplied by the total trading intervals in the billing month.

	Generator Trading Intervals with Capacity Gap, Luzon - 2015					
GEO	129	13	-	-	3	188
HYDRO	-	1,810	55	-	33	30
NATGAS	-	-	-	22,749	179	18
OIL	3,403	81	-	-	-	257
Grand Total	3,532	1,960	6,606	22,759	380	1,287

continuation...	Day-ahead offer	Dependable Capability	Others	No offer / reason	Total
BIOFUEL	-	2,824	668	1,395	4,887
COAL	157	748	10,576	18,945	43,817
GEO	-	2,290	6,395	2,063	61,069
HYDRO	-	5,705	1,891	60,172	123,028
NATGAS	-	-	1,147	162	24,317
OIL	10,250	1,712	9,880	20,673	93,422
Grand Total	10,407	13,279	30,557	103,410	350,540

Table 98 Customers' Spot Market Exposure - Visayas

APPENDIX 'D'

Summary of Generator Trading Intervals[33] with Capacity Gap - Visayas
26 December 2014 to 25 December 2015

	Generator Trading Intervals with Capacity Gap, Visayas - 2015					
Resource Type	Generating plant outage	Equipment-related concer	Water elevation / availability	NIA IDR	Steam supply	Generator / Equipment test
COAL	3,099	565	-	-	6	13
GEO	5,848	822	-	-	9,174	34
OIL	30,373	4,448	-	-	-	518
Grand Total	39,320	5,835	-	-	9,180	565

continuation...	Ambient Conditions	Line Limitation	Coal Quality	Fuel oil operation	Star-up profile	Shutdown profile
COAL	-	-	-	-	32	1
GEO	-	3	-	-	-	80
OIL	-	7	-	-	282	1,460
Grand Total	-	10	-	-	314	1,541

continuation...	Day-ahead offer	Dependable Capability	Others	No offer / reason	Total
COAL	-	-	70	3,797	7,583
GEO	-	4,180	133	1,101	21,375
OIL	50	4,083	1,991	47,159	90,371
Grand Total	50	8,263	2,194	52,057	119,329

Table 98 Customers' Spot Market Exposure - Visayas

33 Total generator resource trading-intervals in Visayas – calculated as the number of registered generator resource nodes multiplied by the total trading intervals in the billing month.



Mr. Julius Eleazar Bunyi & Mr. Chuckie Toque

Planning and Corporate Policy Section (Corporate Planning and Communications Department)



• INTEGRATED •

MARKET

DEVELOPMENT

- PLAN: -

ROAD MAP

for

WESM
DEVELOPMENTS

2016 - 2020

EXECUTIVE SUMMARY

The Integrated Market Development Plan (IMDP) serves as the road map for market developments of the Philippine Wholesale Electricity Spot Market (WESM). It contains the activities that PEMC shall undertake in order to establish market mechanisms mandated by relevant laws (i.e. EPIRA and RE Act) and policies promulgated by the DOE. The IMDP considers research and development of financial instruments to further empower trading participants by providing more options for electricity risk management and trading.

This document has the following objectives:

1. Establish a methodology for the creation and establishment of new market development projects
2. Determine the optimal timeline in the conceptualization, development and implementation of new mechanisms in the market, consistent on relevant energy laws and policies.
3. Provide an electricity market roadmap that matches the short-term and long-term goals with specific details and measures in the achievement of these goals consistent with the PEMC's Corporate Strategic Plans; and
4. Serve as reference for determining the resource requirements needed to establish and operate new features in the electricity market, in order for the said requirements to be incorporated in PEMC's ISSP, which is a significant component of PEMC's market fee filing to the ERC; and
5. Serve as a reference for the DOE, ERC and other relevant agencies in the crafting and harmonization of policies and issuances that are pertinent to the governance and operations of the Philippine Electricity Market in ensuring an efficient and transparent electricity bourse.

Among the market development projects included in this document are the following:

1. Major enhancements to WESM Design and Operations (WESM Design Study)
2. Reserve Market
3. Demand Response Programs
4. Implementation of Preferential Dispatch for Intermittent Renewable Energy Resources
5. Financial Transmission Rights
6. Full Implementation of Retail Competition and Open Access
7. Market for electricity derivatives
8. RE Certificates Market
9. Mindanao Electricity Market

On the other hand, related system development and enhancements activities to support market development project are the following:

1. New Market Management System (NMMS)
2. Central Registration and Settlement System (CRSS) 2.0
3. Accounts Management System (AMS)
4. Electricity Market Database and Reporting Platform (EMDRP)

With the development of IMDP now being part of the company's planning process, PEMC has now an integrated approach in the development of new market mechanisms that will spearhead the continuous evolution of the WESM. With an integrated approach to market development projects, PEMC is now able to effectively formulate detailed strategies and solutions to allocate resources and develop/enhance market systems to support operations and governance of the Philippine Electricity Market.

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INTRODUCTION

BACKGROUND

The WESM has been operating for more than ten (10) years since its commencement on 26 June 2016. Over the course of its operations, the market has continued to evolve and expand in terms of features and coverage. Some of the market mechanisms that have been incorporated in the market are the following:

- Compensation mechanisms for generators designated as Must Run Units;
- Price Substitution Mechanism during events of major transmission line congestion; and
- Enhanced mechanism for the flow back of the Net Settlement Surplus.

It can also be observed market has been expanding steadily for the last six (6) years in terms of coverage and the number of trading participants, as listed below:

- Integration of Visayas Grid in the market (2010), allowing generators and customers in the Visayas to participate in a competitive environment;
- Integration of Retail Competition and Open Access (2013), allowing electricity end-users connected in the Distribution System to participate the power of choice; and
- Implementation of Preferential Dispatch for Intermittent Renewable Energy Resources (2014), allowing and providing incentives intermittent renewable energy resources in the Luzon and Visayas to contribute to the generation of power to the grid.

Currently, as prescribed by relevant policies of the DOE and ERC, the core spot market design is undergoing major enhancements in the scheduling and settlement processes (five minute dispatch, ex-ante pricing, and automatic relaxation of constraints). Also, as part of the continuing expansion and evolution of the market, additional market mechanisms are now in the pipeline, namely: the Reserve Market, and the full implementation of Retail Competition and Open Access (RCOA) wherein the contestability threshold will be further reduced to 750 kW in 2016, and to the household level by 2018. Lastly, research and development activities have been initiated for the establishment of the following: establishment of an electricity market in the Mindanao Region, Financial Transmission Rights (FTR), market for the trading of RE Certificates, and electricity derivatives market (Forwards, Contracts for Difference).

With a significant number of developments being introduced in the market, it can be observed that features of existing and new market mechanisms are interrelated with each

other. Consequently, the said mechanisms require development of necessary systems (organizational, infrastructure, change management) to support its implementation. Without a careful and holistic approach in its impact to processes and systems, these new market mechanisms may result to conflicting provisions with each other – this can result to inefficient design of policies or expensive change orders in the system development which can result to delays in the implementation.

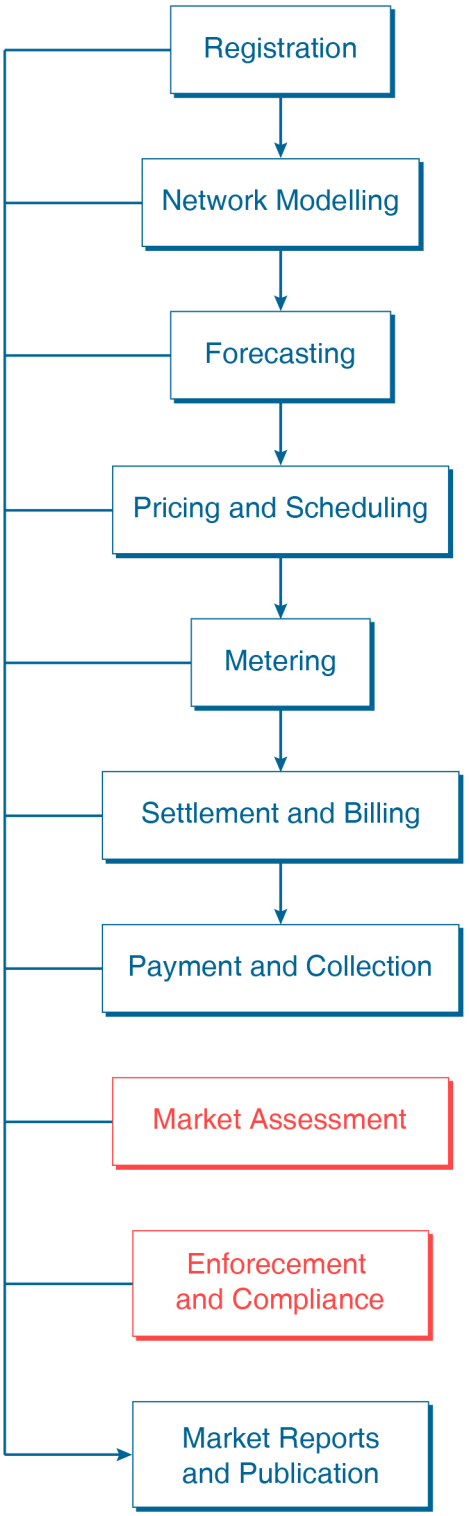
In order to effectively introduce new mechanisms in the market, an Integrated Market Development Plan must be established, in order to:

1. Implement policy and regulatory directives relevant to electricity market operations and governance;
2. Provide a comprehensive approach in the management of all the market developments in the electricity market;
3. Align market development initiatives to efficiently allocate resources; and
4. Identify and resolve gaps, if any; and
5. Develop guidelines/standards for the development of new/existing market mechanisms.

ROLE OF THE PHILIPPINE ELECTRICITY MARKET CORPORATION

The PEMC serves as the Market Operator (MO) of the Wholesale Electricity Spot Market (WESM) and the Central Registration Body (CRB) in the retail market (integrated in the WESM). Under the Renewable Energy Act, PEMC shall serve as RE Registrar for the RE Certificates Market. PEMC, as the operator and the governance arm of the integrated retail and wholesale market, is required to efficiently perform its functions, and to perform necessary actions such as rules and manuals amendments, and modifications of its systems to ensure continuous improvement of the market.

Shown in Figure 1 is the overview of PEMC's core functions as the Market Operator and the Central Registration Body in the Philippine Electricity Market.



Registration involves procedures pertaining to the application of any individual or group to the WESM to become a market participant whether as direct or indirect. It also includes updating of the list of the WESM Members. The Registration process also includes the facilitation of Customer Switching among retail market participants.

Modelling involves updating the Market Network Model (MNM), which corresponds to a mathematical representation of different elements in the power system.

Load forecasts are conducted to estimate the demand for all customers in the WESM.

The prices and schedules are currently determined in an hourly basis, based on the current Market Network Model, load forecasts, and the bids and offers.

Metering processes involve consolidation and validation of the metering information submitted by Metering Service Providers.

The hourly settlement amounts are then calculated based on the resulting prices and schedules, and spot quantities based on the quantities submitted by MSPs (MQ) and TPs (BCQ). Based on the Trading Amounts, settlement statements and billing invoices are then issued to WESM Members on a monthly basis.

PEMC also serves as the Payment and Collection Agent attributed to WESM Transactions for all registered Trading Participants.

PEMC performs continuous assessment of the performance of the market and publishes monitoring indices to gauge its performance.

Breaches in the market rules are investigated by the Enforcement and Compliance Office of PEMC.

PEMC also publishes market information and reports through its public website.

Figure 1 Overview of the Market Processes

PEMC, with the regulatory and policy support from the Department of Energy (DOE) and the Energy Regulatory Commission (ERC), also has a vital role in the continuous development of the electricity market. As the market continues to evolve and expand, PEMC is responsible in conceptualizing/enhancing, developing and implementing new market mechanisms to promote a level playing field among power industry stakeholders.

OBJECTIVES

The Integrated Market Development plan aims to:

- Establish a methodology for the creation and establishment of new market development projects;
- Determine the optimal timeline in the conceptualization, development and implementation of new mechanisms in the market, consistent on relevant energy laws and policies;
- Provide an electricity market roadmap that matches the short-term and long-term goals with specific details and measures in the achievement of these goals consistent with the PEMC' Corporate Strategic Plans; and
- Serve as a reference for the DOE, ERC and other relevant agencies in the crafting and harmonization of policies and issuances that are pertinent to the governance and operations of the Philippine Electricity Market in ensuring an efficient and transparent electricity bourse.

COVERAGE

The Integrated Market Development Plan covers the following market development projects:

- Major enhancements to WESM Design and Operations (WESM Design Study);
- Reserve Market;
- Demand Response Programs;
- Implementation of Preferential Dispatch for Intermittent Renewable Energy Resources;
- Financial Transmission Rights;
- Full Implementation of Retail Competition and Open Access;
- Market for electricity derivatives;
- RE Certificates Market;
- System Development and Enhancements;
- New Market Management System (NMMS);
- Central Registration and Settlement System (CRSS) 2.0;
- Accounts Management System (AMS);
- Electricity Market Database and Reporting Platform (EMDRP);
- Mindanao Electricity Market; and
- Other projects that may be developed pursuant to DOE and ERC's directories.

POLICY AND REGULATORY SUPPORT

Development of new market mechanisms requires policy and regulatory support from the DOE and the ERC. Thus, approvals of the necessary policy and regulatory issuances must be considered in the timelines. Furthermore, establishment of new market mechanisms would also require funding support. The said funds to support these endeavors would be recovered from the market fees that require ERC approval.

METHODOLOGY

Shown in Figure 2 is the methodology employed in the development of the market development plan. The results of the procedures conducted is discussed on the succeeding chapters of this document.

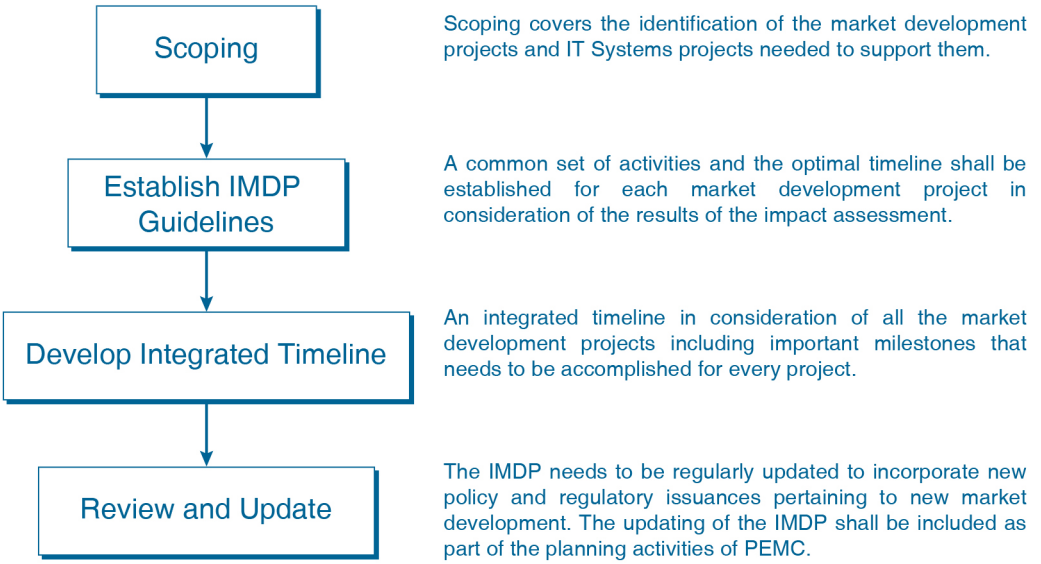


Figure 2 Methodology in developing the IMDP

MARKET DEVELOPMENT PROJECTS

This section provides a brief description and list of activities and timeline of the market development initiatives of the company.

PROJECTS IN THE PIPELINE

Projects in the pipeline are market development projects in which the DOE has already relevant policies directing its implementation.

1. Enhancements to WESM Design and Operations

The PEMC has commissioned an independent consultant (Intelligent Energy Systems (IES), SW Advisory and Dr. Ross Baldrick) to conduct an assessment of the current WESM design and provide advisory and recommendations on market issues. The study was done in two phases where Phase 1 provides the findings and recommendations of IES on market design issues, on the minimum stable load (Pmin), must-offer rule (MOR), constraint violation coefficients (CVCs), pricing error notices (PENs), and must-run units (MRUs). The Phase 2 details the recommendations on market and system operations in relation to possible implementation of a shorter dispatch interval. The study was completed last January 2014 and was endorsed to the DOE for evaluation.

The DOE then issued a circular last 23 October 2015 providing enhancements to the design operations of the WESM in consideration of the WESM Design Study. Among the enhancements to be adopted are the following:

- Removal of Pmin constraint in the MDOM;
- Shorter trading and dispatch interval of five (5) minutes;
- Ex-ante pricing only for every five (5)-minute trading and dispatch interval;
- One (1)-hour settlement interval for settlement purposes based on weighted average of the five (5)-minute ex-ante prices;
- Automated pricing corrections;
- Mandatory integration of the Distribution Utilities' sub-transmission network, which materially affect dispatch prices and schedules in the WESM into the Market Network Model;
- Changing values and priorities of some of the Constraint Violation Coefficients (CVC);
- Imposition of WESM offer cap and floor for energy and reserve;
- Implementation of hourly Day Ahead Projections (DAP) with sensitivities, and Hour Ahead Projections (HAP); and
- Short term nodal load forecasting.

2. Reserve Market

Reserves are ancillary services that are necessary to support the transmission of energy from generating resources to loads while maintaining reliable and secure operation of the transmission system. The trading of reserves in the market will facilitate the full benefits of co-optimized energy and reserves.

The DOE through Department Circular No. DC 2013-12-0027 initially set the Commercial Launch Date of WESM Reserve Market on 26 March 2014 subject to fulfilment of certain conditions. However on 26 March 2014, the DOE issued Department Circular No. 2014-03-0009 where it provides for the new commercial launch date for the reserve market subject to approval of the Pricing and Cost Recovery Mechanism (PCRM) by the ERC it also provides for the commencement of the Central Scheduling and Dispatch of Energy and Contracted Reserves. The Central Scheduling and Dispatch of Energy and Contracted Reserves then commenced last December 2015.

The Reserve Market is proposed to be launched in two (2) stages. The first stage will be based on the existing reserve categories as prescribed in the Pricing and Cost Recovery Methodology (PCRM) currently filed in the ERC, and the commencement of the said stage is contingent on ERC's approval of the said filing. The final stage is based on the recommended design of an external expert submitted to the ERC and targeted to be implemented upon adoption of the ERC of the said design through the amendment of the Philippine Grid Code.

3. Full Implementation of Retail Competition and Open Access (RCOA)

Retail Competition refers to the provision of electricity to a Contestable Market by Suppliers through Open Access, while Open Access refers to the system of allowing any qualified Person the use of transmission, and/or Distribution System and associated facilities subject to the payment of transmission and/or distribution retail wheeling rates duly approved by the ERC .
Per EPIRA Section 31(e), implementation of the RCOA will be done in phases. Initial implementation of the RCOA will allow participation of electricity end-users with at least 1 MW monthly average peak demand. Phase 2 will lower the threshold level to 750kW and aggregation of demand will also be allowed. After this, the threshold will be gradually reduced

until it reaches the household level.

The commercial operations of RCOA (Initial Phase) started last 26 June 2013. Since then the market has grown to a total of 395 participants (343 of which are contestable customers).

Last June 2015, the DOE issued a department circular for the full implementation of RCOA. In the circular, Contestable Customers are now mandated to participate in the market and are required to secure a Retail Supply Contract with a Supplier by 26 June 2016. During the said period, the contestability threshold will now then be reduced to 750 kW. Demand aggregation over a contiguous area will also be allowed starting the said date subject to the issuance of the demand aggregation rules of the ERC. In 2018, the contestability threshold will then be reduced to 501 kW and participation will be voluntary for electricity end-users below 501 kW.

Below is the list of activities and the corresponding timeline for the full implementation of RCOA.

- Submission of the Implementation Plan to DOE (2015);
- Market Structure Development / Updating of Rules and Manuals (2016);
- System Infrastructure Development (2016 – 2017);
- Trial Operations (2017);
- Readiness Assessment (2017); and
- Commercial Operations(2017).

4. Implementation of Preferential Dispatch for Intermittent Renewable Energy Resources

By virtue of R.A. 9513 (Renewable Energy Act), intermittent RE resources shall be prioritized in the dispatch of generators. Further policies to implement said law is further detailed in the must and priority dispatch guidelines issued by the DOE last March 2015. Under the said guidelines, PEMC is tasked to perform necessary amendments to the WESM Rules and Manuals to accommodate the variable RE Resources.

The list of activities related to this endeavor are the following:

- Amendments to the WESM Rules (completed);
- Amendments to the Market Manuals (Under RCC deliberations); and
- System Development and Enhancements (2016, 2017).

5. Demand Side Bidding

Demand Side Bidding is already a feature of the existing market design and shall continue to be adopted in the major enhancements in the WESM design and operations. However, customers in the WESM have yet to exercise the said feature of the market to enable them to actively participate in the pricing and scheduling process.

This market development project covers activities in relation to promote participation of WESM Members to participate in the existing design of the Demand Side Bidding. Additional mechanisms and financial incentives for customers are currently under study and shall be categorized as a market development project under research and development:

- Conduct of system tests related to the demand side bidding functionality of the Market Management System;
- Assessment of the needed infrastructure needed to implement Demand Side Bidding; and
- Development of policies to promote demand side bidding.

PROJECTS UNDER RESEARCH AND DEVELOPMENT

Projects under research and development refers to market development projects that are awaiting policy directions from the DOE or it requires the necessary funding support for full implementation. Thus, the activities related to these projects are mostly focused on research and development and the said timelines indicated would most likely change depending of the policy directions of the DOE and budget approval from the ERC.

1. Renewable Energy Certificates Market

Republic Act No. 9513 also known as the Renewable Energy Act of 2008 is an Act promoting the development, utilization and commercialization of Renewable Energy resources. In accordance with Section 8 of R.A No. 9513 "the DOE shall establish the Renewable Energy Market and direct PEMC to implement changes to the WESM Rules specific to the operation of REM under the WESM".

Based on the legal mandates, the PEMC has three (3) major roles to play:

1. Implement changes to the WESM Rules, as well as its operations, to incorporate the rules specific to the operation of the RE Market and Feed-in-Tariff system under the WESM;
2. Establish the RE Registrar that would issue, keep and verify RE Certificates; and
3. Operate the RE Market, upon its establishment by the DOE.

Below are the activities in the implementation of the RE market:

- Market Structure Development (2017);
- System Infrastructure Development (2018);
- Trial Operations (2019);
- Capacity Building (2019);
- Readiness Assessment (2019); and
- Commercial Operations(2019).

The abovementioned activities are contingent to the following activities:

1. Issuance of the REM Rules by the DOE;
2. Approval of the GEF5 Grant; and
3. Issuance of the RPS Rules by the DOE.

2. Establishment of an Electricity Market in Mindanao

With the entry of additional capacities in Mindanao starting 2016, the said region is set to experience a supply surplus for the first time since 2010. In the years 2017 and 2018, projected supply in Mindanao is expected to increase to 3,616 MW and 3,669 MW respectively. With the demand expected 1,837 MW and 1,965 MW in the same years, there would be a significant increase of the supply margin of 1,780 MW and 1,704 MW. Furthermore, interconnection of Mindanao Grid to the Visayas Grid has also been explored, which may potentially benefit the said grids by allowing energy exchanges in both regions. With these developments, the feasibility of establishing an electricity market for Mindanao is now being conducted in order to promote power industry competition.

3. Financial Transmission Rights

A Financial Transmission Right (FTR) may be generally defined by the following characteristics:

- It is a financial instrument;
- The value of the FTR is based on the differences among LMPs; and
- The holder of an FTR receives compensation from congestion costs paid to the market.

Activities related to the development of FTRs are primarily research and development on the best fit the Philippine setting. A concept paper was already submitted to DOE for their further direction.

The FTR is provided for in Clause 3.12 of the WESM Rules.

4. Electricity Derivatives Market

A market for electricity derivatives primarily serve as a risk management tool by trading participants to manage the price volatilities in the spot market. Operating a market for electricity derivatives provides the following benefits:

- Price certainty;
- Minimize the spot price volatility risk; and
- Trading on the derivatives market effectively mitigates market power in the spot market as trading participants will no longer have the incentive to exercise uncompetitive behavior.

Initially, electricity derivative product types to be considered for trading are forwards and futures contracts.

Activities in relation to the electricity derivatives market development are as follows:

- Engagement with an external expert for technical assistance (2016)
- Workshops and capacity building (2016)
- Market Structure Development (2016 – 2017)
- Market Systems Development (2017)
- Approval of the Rules (2017)

It must be noted that the activities pertaining to the development of the derivatives market is contingent to the policy direction of the DOE.

5. Other Demand Response Programs

Other Demand Response covers development of additional mechanisms to promote active participation of customers in market driven demand response programs. This covers development of new demand response mechanisms and additional financial incentives for the existing demand side bidding functionality of the wholesale market.

MARKET SYSTEMS UNDER DEVELOPMENT

Market systems listed in the IMDP covers IT systems that supports the operation of the market development projects in the pipeline.

1. Acquisition of New Market Management System (NMMS)

Central to the operation of the market is the Market Management System (MMS). The existing MMS is being used to operate the market in Luzon and Visayas region since its commercial

operation in 2006 and 2010, respectively, and has been utilized since its acquisition in 2004.

The new MMS shall have all the desirable features and functions of the current MMS as well as new functions and features that either enhance or replace the existing ones. The acquisition of the new MMS shall also consider the results of the WESM Design Study and shall incorporate the other market development initiatives of the company.

Below are the activities for the acquisition of the New MMS:

- NMMS Project Implementation (2015 – 2017); and
- MMS-NMMS Parallel Run (2017).

2. Central Registration and Settlement System 2.0

The Central Registration and Settlement System (2.0) is the system that shall support the registration, metering and settlement functions of the integrated wholesale and retail market. Together with the New Market Management System, the CRSS 2.0 shall implement the major enhancements in the market design, particularly the calculation of settlement amounts. Furthermore, the said system shall support PEMC's function as the Central Registration Body (CRB) for the full implementation of Retail Competition and Open Access.

The development of the said system shall be in two (2) phases. The first phase covers the development of the necessary participant interfaces and is targeted to be completed during the first quarter of 2017, while the second phase covers processes involving metering and settlement calculations and is expected to be completed during the third quarter of 2017. It shall be launched simultaneously with the NMMS with the adoption of the enhancements to the WESM Rules and Manuals and the Price Determination Methodology.

The activities for the development of this project are the following:

- Tender process (2016)
- Phase 1 Development (2017)
- Phase 2 Development (2017)
- Trial Operations (2017)

3. Accounts Management System

The Accounts Management System is the system that aims to automate the payment and collection processes of the market.

The activities for the development of this project are the following:

- Completion of development to comply to BIR Directives
- Testing activities

4. Electricity Market Database and Reporting Platform (Business Development and External Services Phase II)

The Electricity Market Database and Reporting Platform (EMDRP) is envisioned to be the central repository of market data and the central platform for market reporting, analysis, and monitoring. It is also envisioned to manage information in relation to future market mechanisms such as the reserve market, renewable energy market and other market mechanisms that PEMC aims to establish in the future. The EMDRP is designed and intended for data mining and analysis of large amount of information in support to market applications so as not to

degrade and adversely affect the system performance. The EMDRP solution will cover three (3) main components, namely the Data Warehouse, the Business Analytics and the Content Management.

Below are the activities in the implementation of the EMDRP:

- Completion of Development (2016);
- Deployment Activities (2016);
- Use Acceptance Testing (2015 – 2016);
- Roll-out Activities (2016);
- Functional Training (2016); and
- Project Go-Live (2016).

IMDP WORK STREAMS

Introduction of new market mechanisms take considerable time and effort to ensure successful implementation. Each market development project also involves ensuring proper execution of change management procedures to ensure that PEMC, power industry participants, service providers, and policy and regulatory bodies are ready for eventual Go-Live of such projects.

1. MARKET STRUCTURE DEVELOPMENT

Covers activities pertaining to research and development and market concept and design and drafting of applicable rules and protocols for new and existing market mechanisms. This work stream should also cover impact assessment of the said mechanism to existing market processes and systems.

2. POLICY AND REGULATORY APPROVAL AND SUPPORT

Covers necessary policy and regulatory direction and approval from both the DOE and ERC in order to develop and implement the market development projects. This include funding approval for the development and eventual implementation of the market design, rules and IT systems. Promulgation of the market rules and commencement of commercial operations.

3. SYSTEMS DEVELOPMENT AND ENHANCEMENTS

Covers activities related to development of internal and external IT infrastructure for new market mechanisms.

4. TRAINING AND CAPACITY BUILDING

Covers activities pertaining to training and development of involved units (internal and external). Also include stakeholder and service provider trainings and workshops.

5. ROLLOUT ACTIVITIES

Covers activities pertaining to system trials, readiness assessments to ensure smooth implementation/integration of new market mechanisms and systems. The said activity also covers proper turnover of the day-to-day activities to concerned process owners.

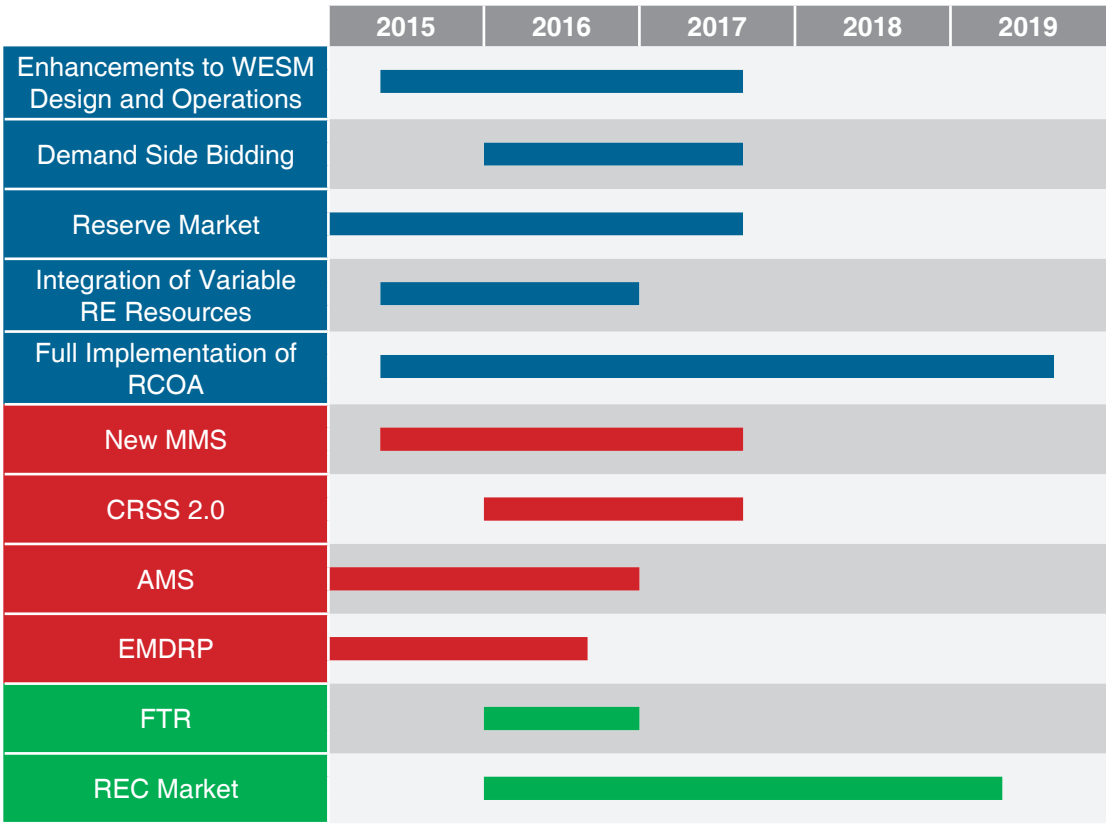
6. STRATEGIC SUPPORT ACTIVITIES

PEMC resources are highly limited and tightly regulated. Thus, PEMC would need to secure additional resources through supplemental filings to the ERC or securing grants/loans from multi-lateral institutions to pursue establishment of new market mechanisms. It is with this reason that strategic support activities need to be considered.

Strategic Support Activities covers activities pertaining to aligning and effectively utilizing PEMC's resources (Budget, Strategic Planning, ISSP, and Manpower Allocation) to each project being under taken by PEMC.

TIMELINE

Figure 3 shows the integrated timeline of the market development projects included Integrated Market Development Plan.



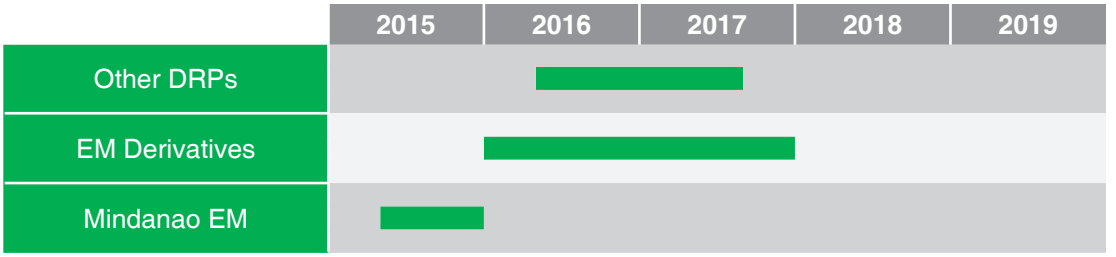


Figure 3 Integrated Timeline for the IMDP

Important activities and milestones for each market development project are shown in Table 1. It can be noted that securing policy and regulatory approval is very critical in the success of the various market development projects in pipeline, particularly in the eventual translation of the said approvals to the market systems that are currently under development. It is ideal that PEMC would need to secure the said approvals first before proceeding with market systems development. However, given the tight timelines, PEMC is constrained to commence development of the said market systems. This effectively exposes PEMC to project risks as there could be delays in securing the necessary approvals. Such delays could result to change orders to the development of market systems that results to additional costs on PEMC's end.

On the other hand, for projects under research and development, it is highly recommended that PEMC secures the necessary policy approvals first before commencing development given that the said projects are only in the conceptual stages.

Market Development Project	Milestone	Responsible Entity
Enhancement of WESM Design and Operations	Promulgation of the Policy on Enhancement to WESM Design and Operations	DOE
	Development of WESM Rules	PEMC
	Development of Pricing Related Market Manuals	PEMC
	Development of Other Market Manuals	PEMC
	Promulgation of WESM Rules Changes	DOE
	Promulgation of Pricing Related Market Manuals	DOE
	Resolution of Pricing Related Market Manuals	ERC
	Promulgation of Other Market Manuals	ERC
Demand Side Bidding	Assessment of Systems and Processes	PEMC
Reserve Market	Regulatory Filings	PEMC
	Approval of PCRM	ERC
Integration of Variable RE Resources	Promulgation of Must Dispatch Guidelines	DOE
	Promulgation of WESM Rules Changes	DOE
	Promulgation of Market Manual Changes	DOE
Full Implementation of RCOA	Promulgation of Policy	DOE
	Development of Implementation Plan	PEMC
	Streamlining of retail market processes	PEMC
	Declaration of the reduction of contestability threshold to 750kW	ERC
	Development of initial design for demand aggregation	PEMC
	Declaration of the reduction of contestability threshold to 501 kW and below	ERC
	Promulgation of Demand aggregation rules	ERC

Market Development Project	Milestone	Responsible Entity
New MMS	Completion of Development	PEMC
	Trial Operations	PEMC
	Go Live	PEMC
CRSS 2.0	Completion of Phase 1 Development	PEMC
	Trial Operations	PEMC
	Completion of Phase 2 Development	PEMC
	Go Live	PEMC
EMDRP	Completion of Development	PEMC
	Go Live	PEMC
FTR	Submission of Concept Paper to DOE	PEMC
REC Market	Secure Funding for GEF5	PEMC/DOE
	Promulgation of the RPS Rules	DOE
	Market Design Development	PEMC
	Rules Development	PEMC
Other Demand Response Programs	Submission of Concept Paper to DOE	PEMC
EM Derivatives	Submission of Concept Paper to DOE	PEMC
Mindanao EM	Submission of Implementation Plan to DOE	PEMC

Table 1 Important Activities and Milestones

As discussed in Chapter 4, successful market development project implementation also covers execution of proper change management procedures to ensure that PEMC, market players, service providers and policy and regulatory bodies are ready. Thus, the integrated timeline must also take into account activities in relation to ensuring readiness of relevant parties.

An integrated timeline is shown in Figure 4. Activities pertaining to system development and enhancements, training and capacity building and roll-out activities mostly cover market development projects in the pipeline. It must be noted that there are no system development and enhancements, training and capacity building and roll out activities listed yet to projects under research and development since there are no significant policy and regulatory approvals.

The need for periodic review of the IMDP shall form part of the strategic support activities that is conducted on an annual basis.

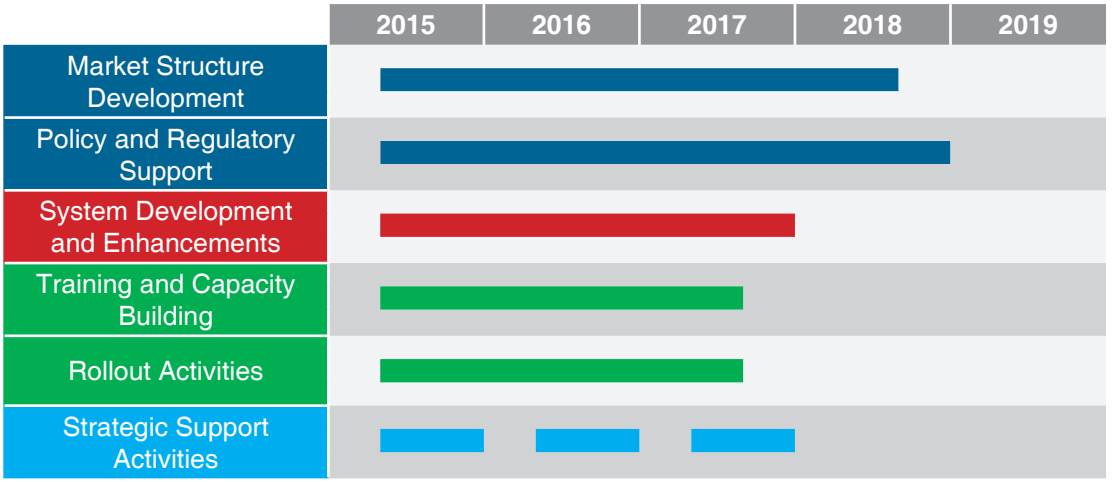


Figure 4 Integrated Timeline in Consideration of the Work Streams

REVIEW AND UPDATING OF THE IMDP

The IMDP shall be regularly reviewed and updated on a regular basis and the said activity shall be part of the planning activities of PEMC. Shown in Figure 5 is the updated planning process of PEMC in consideration of the review and updating of the IMDP.

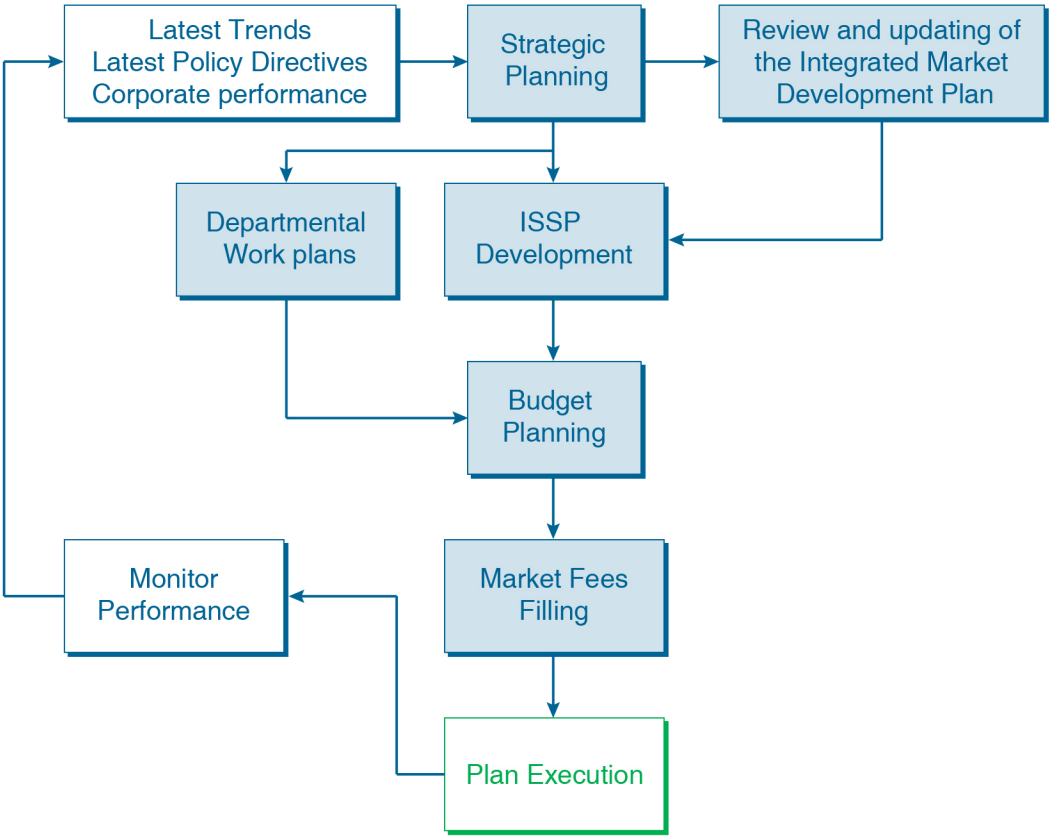


Figure 5 PEMC's planning activities including the development of the IMDP

With the development of IMDP now being part of the company's planning process, PEMC has now an integrated approach in the development of new market mechanisms that will spearhead the continuous evolution of the Philippine Electricity Market. With an integrated approach to market development projects, PEMC is now able to effectively formulate detailed strategies and solutions to allocate resources and develop/enhance market systems to support operations and governance of the Philippine Electricity Market.

CONCLUSIONS

An Integrated Market Development Plan is now established that now serves as the road map for the development of the Philippine Electricity Market. The IMDP considers not only major enhancements from both the core wholesale and retail markets, but also considers the research and development of financial instruments to further empower trading participants.

The establishment of the optimal timeline for various projects of PEMC was also achieved. This was accomplished as holistic approach in assessing the impact of the various projects of PEMC was conducted.

The IMDP shall serve as reference for the policy and regulatory agencies of the power industry in the crafting and harmonization of policies and regulatory issuances that are pertinent to the governance and operations of the Philippine Electricity Market in ensuring an efficient and transparent electricity bourse.

Lastly, the methodology for determining the IMDP can also serve as a methodology for the creation and establishment of new market development projects in the future.



Atty. Criselda S. Martin-Funelas

Atty. Funelas is the Chief of Staff of the Office of the President and Vice-President of Legal Deparment.

3

WESM

as an *Enabler:*

THE LEGAL BASIS - OF THE - WESM FRAMEWORK

INTRODUCTION

The Wholesale Electricity Spot Market (WESM) is the only electricity spot market in the Philippines. It is a product of Republic Act No. 9136 or the Electric Power Industry Reform Act (EPIRA). In its simplified concept, the WESM, just like any market, serves as the venue for the wholesale buying and selling of a fungible and "must-be-consumed-at-the-point-of-production"[1] commodity that is called electricity. Owing to the very technical nature of such a commodity, the WESM process therefore appears complicated and esoteric to a layperson. However, an understanding of its basic legal framework would assist in the appreciation of the role that the WESM plays in the country's development. Further, realizing that the WESM brought into flesh the economic principles that the framers of the 1987 Constitution debated on in the crafting of its Article XII would make both the private and the government aware of the need to protect its transparency and independence.

THE 1987 CONSTITUTION

THE ECONOMIC MODEL OF THE 1987 CONSTITUTION

Article XII of the 1987 Constitution enshrines the economic goals of our country. A reading of the deliberations of our Constitutional Commission (ConCom) shows how the framers carefully worded the provisions to embody what they believed to be the direction that the country should take to achieve economic success. There were extensive deliberations on the floor but the framers essentially had the same vision – an economy that recognizes the significance of agriculture, the needed balance between protecting Filipino industries and liberalizing trade to achieve competition, and the flexibility of Congress to adjust with the times -- for the purpose of raising the quality of life of the Filipinos especially the underprivileged. This is succinctly provided in all of Section 1 of Article XII which provides:

> "SECTION 1. The goals of the national economy are 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 raising the quality of life for all, especially the underprivileged.
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> The State shall promote industrialization and full employment based on sound agricultural development and agrarian reform, through industries that make full and efficient use of human and natural resources, and which are competitive in both domestic and foreign markets. However, the State shall protect Filipino enterprises against unfair foreign competition and trade practices.
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> In the pursuit of these goals, all sectors of the economy and all regions of the country shall be given optimum opportunity to develop. Private enterprises, including corporations, cooperatives, and similar collective organizations shall be encouraged to broaden the base of their ownership."

The role of the private sector in industrialization and its partnership with the government was the crux of the various discussions during the deliberation of this constitutional provision. Commissioner Edmundo G. Garcia, a member of the ConCom, argued on the need for

1 Electricity cannot be stored in large quantities and therefore must be consumed when produced.

economic democratization and used the term "mixed economy".[2] Commissioner Bernardo M. Villegas explained what a mixed economy is upon interpellation of Commissioner Alberto M. K. Jamir, to wit:

> "MR. VILLEGAS. xxx
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> A 'mixed economy' is an economy where economic activities are in the hands of private individuals, whether they be single proprietorships, partnerships, corporations, cooperatives, without any prejudice to the possibility of the state also operating economic enterprises that are considered vital for the common good. So, this has to do with the way economic enterprises are owned and operated. A 'mixed economy' is one that admits of both possibilities – economic enterprises in the hands of private individuals and economic enterprises in the hands of the state. As to which specific blend is chosen in a very particular period of a nation's history will depend on circumstances. As Commissioner Monsod was saying, government expenditures as a source of investment for establishing economic enterprises are extremely limited right now because as we very well know, as we go through from one social justice provision to another, we need billions and billions to give health services, to even subsidize the expropriation of land, et cetera. After the government tries to implement the Article on Social Justice, the government will be bankrupt. Therefore, we just have to leave the establishment of economic enterprises to private individuals."[3]

The private sector referred to above was not limited to business groups but to a broader group. On the query of Commissioner Garcia, Commissioner Villegas explicitly said that "the word 'private' is not limited to profit-making for business groups" but should relate to the concept of social or common good and thus includes "cause-oriented groups, cooperatives, nongovernmental organizations, precisely any grouping that is not part of the government sector."[4]

Evidently, the ConCom members were not purists of a single economic model. It was not a philosophy of laissez faire nor was it a protectionist model that they crafted. This was a running philosophy since the 1935 and 1973 Constitutions which was carried over and improved in the 1987 Constitution. In the landmark case of *Edu v. Ericta*[5], the Supreme Court, through the ponencia of Justice Enrique Fernando, explicitly stated that laissez faire was already rejected as an economic policy as early as 1919.[6]

This was likewise mentioned in the sponsorship of Commissioner Villegas when he said that "[t]he principle of solidarity xxx requires individuals and private groups to deliberately contribute to the common good in the performance of daily tasks. This principle clashes with the assumption of laissez-faire economics which overly glorifies free enterprise as the road to economic prosperity for all. Experience has shown that there is no invisible hand which automatically promotes the common good in an environment where everyone is encouraged to pursue his selfish economic interest."[7]

The primary role given to the private sector did not, however, diminish the authority of the government to intervene when necessary. It is clear from the discussion that the mixed economy recognizes the role of the government to regulate for the common good. Commissioner Villegas stated this clearly –

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2 Records of the Constitutional Commission, August 13, 1986, p. 272.
3 Records of the Constitutional Commission, August 14, 1986, p. 313.
4 Records of the Constitutional Commission, August 13, 1986, p 273.
5 G.R. No. L-32096 October 24, 1970.
6 Edu v. Ericta, G.R. No. L-32096 October 24, 1970 (citations omitted).
7 Records of the Constitutional Commission, August 13, 1986, p. 253.

MR. VILLEGAS. Also, it is explicitly stated that the freedom of initiative is limited by the duty of the State to promote distributive justice and to intervene when the common good so demands. I think it is very clear that we are not anti-State in situations where it is very clear that the State has to intervene. Definitely that demand for the civil justice will prevail over freedom of initiative.[8]

THE EPIRA IMPLEMENTATION OF THE ECONOMIC GOALS OF THE 1987 CONSTITUTION

Fr. Joaquin S. J. Bernas, also a member of the Constitutional Commission, called the three identified economic goals[9] in Section 1 of Article XII as the "dual goal of dynamic productivity and a more equitable distribution of what is produced."[10] The recognition of dynamic productivity and equity brings into fore the involvement of the private sector as enablers and enabled; enablers of the economy which the government must enable. The private sector is encouraged to broaden the base of their ownership which was discussed to mean more people participating in the ownership of the private enterprise.

In the electricity industry, the philosophy of the 1987 Constitution on private sector participation was translated initially via Executive Order No. 215 s 1987 which allowed independent power producers (IPPs) to engage in power generation. When Republic Act No. 6957 or the BOT Law was passed, the privatization policy was adopted to "minimize the burden of infrastructure projects on the national government budget, minimize external borrowing for infrastructure projects, and use the efficiency of the private sector in delivering a public good."[11] Thereafter, the Electric Power Crisis Act was passed in 1993 which preceded the passage of Republic Act No. 9136 or the Electric Power Industry Reform Act (EPIRA) finally in 2001.[12]

As generally known, the government controlled the generation and transmission aspects of the electric power industry[13] prior to the passage of the EPIRA. By virtue of Commonwealth Act No. 120 which was subsequently amended by several Presidential Decrees[14] and finally revised via Republic Act No. 6395, the government, through the National Power Corporation (NPC), undertook the construction of various power plants in the country to meet its obligation of providing the electricity needs of the country. Such mandate entailed huge costs which mostly came from foreign loans because internally-generated income of the NPC was not sufficient. However, the NPC cannot simply recover its cost from the public through high electricity rates without incurring the ire of the electorate. Thus, it was caught in a quicksand of debts and its operations were sacrificed.

Recognizing the contribution that the private sector can make, the EPIRA unbundled the power industry and opened up its generation and transmission sectors to investors. The generation sector was no longer considered a public utility, thereby removing it from the requirement of being a Filipino company and allowing foreign entities to own power plants. The transmission facilities were also prepared for privatization either via an outright sale or a concession contract but, being the backbone of our electricity grid, remained as public utilities and therefore

8 Records of the Constitutional Commission, August 13, 1986, p. 273.
9 The three goals are: (1) more equitable distribution of opportunities, income, and wealth; (2) sustained increase in the amount of goods and services produced by the nation for the benefit of the people; and (3) expanding productivity as the key raising the quality of life for all especially the underprivileged
10 Bernas, The Constitution of the Republic of the Philippines, p. 1006 (1996 ed.).
11 IDEALS, Inc. et al. v. PSALM et al. G.R. No. 192088, October 9, 2012.
12 Records of the Constitutional Commission, August 13, 1986, p. 283.
13 Republic Act No. 6395
14 Presidential Decrees Nos. 380, 395, 758, 938, 1360, and 1443.

subjected to the requirement of being a Filipino company with a franchise. In 2008, the National Grid Corporation of the Philippines (NGCP) won in the public bidding conducted by the Power Sector Assets & Liabilities Management Corporation (PSALM).

The restructuring of the electric power industry was necessary to achieve the dynamic productivity and equity that the 1987 Constitution demanded. The EPIRA is founded on the basic principle of **transparency**. This transparency contributes to better policy and regulation, drives competition among the players, attributes accountability, and leads to efficiency in the operation of the electric power industry participants. Efficiency necessarily means better income; better income for investors begets more investments which in turn translates into more electricity supply, competition, and reasonable prices.

With the primary goal of ensuring energy security, the EPIRA laid down in Section 2 the policies which can be grouped as (1) energy security,[15] (2) energy efficiency and demand side management,[16] (3) competition and transparency,[17] (4) privatization of generation assets and investment,[18] (5) non-discriminatory treatment,[19] and an (6) independent regulator.[20]

THE LEGAL BASIS OF THE WESM FRAMEWORK

IN TERMS OF DESIGN: GROSS POOL, NET SETTLEMENT, MARGINAL PRICING, AND MANDATORY MARKET

The WESM is a **gross pool**. Simply, it means that all electricity injected into the grid are accounted for in the WESM, including electricity purchased between a buyer and a seller through a contract. The operative word is “accounted”. The contract is not settled in the WESM as this is settled between the buyer and the seller. Their agreed price prevails. The quantity of such contractual agreement is deducted or netted out of the WESM because it will be paid using the price agreed upon in the contract. This is called the **net settlement system**. The remaining quantity, after deducting the declared contracted quantity, will now be settled using the WESM price determination methodology approved by the Energy Regulatory Commission (ERC) and then allocated for payment by the customers (buyers) based on their consumption as shown in their metered quantity on a monthly basis. The payment received from the customers will now be allocated to the generators (sellers) based on their metered quantity injected into the grid as well.

It must be emphasized that the WESM does not buy or sell the “traded” electricity. WESM merely administers the trading by producing the dispatch schedule,[21] accounting for the injection and withdrawals, and settling all spot transactions.

The net settlement design finds basis in Section 30 of the EPIRA which states that the WESM “shall provide the mechanism for identifying and setting the price of actual variations from the

15 Rep. Act No. 9136, secs. 2 (a), (b), (g), (h).
16 Rep. Act No. 9136, secs. 2 (k).
17 Rep. Act No. 9136, sec. 2 (c).
18 Rep. Act No. 9136, secs. 2 (i), (d).
19 Rep. Act No. 9136, secs. 2 (e).
20 Rep. Act No. 9136, secs. 2 (j), (f).
21 WESM Rules, Chapter 11 defines “Dispatch Schedule” as the “target loading levels in MW for each scheduled generating unit or scheduled load and for each reserve facility for the end of that trading interval, determined by the Market Operator through the use of a market dispatch optimization model in accordance with clause 3.8.1.

quantities transacted under contracts between sellers and purchasers of electricity". It further states that the rules for the WESM shall "provide the mechanism for determining the price of electricity **not** covered by bilateral contracts." Clearly, the WESM is meant to determine the price of electricity that is **not** covered by contracts. What is not covered by contracts is considered "sold" in the spot market.

While there is a net settlement system, the WESM remains to be a gross pool. The basis of the gross pool is clear in Section 9 (e) of the EPIRA. To quote,

> (e) Subject to technical constraints, the grid operator of the TRANSCO shall provide **central dispatch of all generation facilities** connected, directly or indirectly, to the transmission system **in accordance with the dispatch schedule submitted by the market operator**, taking into account outstanding bilateral contracts. (emphasis supplied)

From the above, it is clear that the dispatch of **all** generation facilities will be centralized and based on a dispatch schedule provided by the WESM operator. In order to provide a dispatch schedule however that will allow for a **central** dispatch, all energy injections must be accounted. Ergo, all generation plants must pass through the WESM in order to be scheduled and centrally dispatched. This makes it a **mandatory market**.

The gross pool and mandatory market design is in keeping with the transparency policy that EPIRA intended to bring to the electric power industry. By accounting all energy injections into the grid, a level playing field is created among electric power industry participants. Generating plants are all treated in the same manner and given the opportunity to offer to the grid on equal footing, regardless of ownership, of contract, and of capacity. A gross pool allows for greater transparency because all injections of energy are monitored in the market.

Transparency is also translated into locational marginal pricing (LMP) or nodal pricing. Simply put, this means that the price of electricity considers the location of the injection and withdrawal. Thus, there are different prices in the various nodes of the electrical system. In adopting nodal pricing, the WESM prices become signals on the inefficiencies and opportunities in the system. Investors who want to put up plants can use the nodal prices to decide on the location of their plants. Further, inefficiencies in the transmission system are also inputs to the plans of the system operator to improve the lines.

The WESM takes into primary consideration the physical infrastructure of the electrical power system. As discussed above, it is meant to make it transparent.

The adoption of the marginal pricing is based on the EPIRA standard of greater operational and economic efficiency under Section 2 (c). In approving the price determination methodology (PDM) of the WESM, the ERC clarified that this is the "cost involved in the entire system in order to satisfy the next one extra megawatt of demand."[22] Further, the ERC did not just focus on the marginal pricing concept but tied it with the LMP design to confirm that the WESM PDM is consistent with the needed transparency and efficiency set by the EPIRA. To quote,

> "The approach, therefore, is not the determination of a market clearing price in the system, which is simply the price where demand is equated with supply. In the optimization process, the determination of a marginal price in the system is through the shadow price on a system constraint deemed to represent incremental costs.
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> xxx

22 Decision dated 20 June 2006, ERC Case No. 2006-007RC, p. 37.

Further, as aforestated, the WESM has adopted the locational marginal pricing concept and the full nodal pricing scheme for settlement purposes. xxx

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As it stands, each market trading node will be assigned to a particular trading participant that intends to buy or sell energy in the WESM. There will be such number of prices generated in a particular interval hour, as there are nodes in the system. Under the current configuration of the system, some of the nodes will consist of multiple units located at the same point in the network and will reflect the same prices.

And as described earlier, the marginal costs of losses and congestion are to be reflected in the resulting locational marginal prices. This pricing scheme is so designed such that where congestion within the network occurs, a higher priced generation may be dispatched to relieve such congestion, and the cost for this generation is borne only by buyers from the location where it occurs, with the nodal price in such location being higher than those in other locations. It thus includes the cost of supplying the more expensive electricity in these locations and provides a precise method for pricing energy that includes transmission congestion costs. Effects of congestion, therefore, will be easily identifiable under the full nodal pricing scheme. In the absence of constraints in the system, and disregarding the losses, prices will be the same at all nodes.

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Arguably, the consideration for the choice of the appropriate pricing scheme is not so much the determination of the actual cost of congestion but the long-term incentives that may arise given the existing constraints in the system. The locational value of electricity will prove to be an effective economic indicator to determine future resource allocation including transmission expansion. Trading participants and potential investors will ascertain, to a certain extent, the value of investing in generation and transmission in those areas. Morevover, projects of the National Transmission Corporation (TransCo) will be set in the appropriate order of priority as it aligns its expansion plans to the resulting prices in the WESM. To treat fundamentally different locations as though they are the same will result in poorer incentives for investments as incorrect signals are produced."[23]

Basis of the Disconnection Policy

The transparency objective of EPIRA necessitates the mandatory nature of the WESM. Section 2.2.4.2 of the WESM Rules provides that "[n]o person or entity shall be allowed to inject or withdraw electricity from the grid unless that entity or person is a registered member of the WESM." Thus, it becomes necessary that all who are connected to the grid **must** register with the WESM.

This provision in the WESM Rules became the basis for the disconnection policy of the Department of Energy in 2010 when it issued DOE DC No. 2010-05-0006. At that time, as the WESM was surfacing accountabilities on withdrawals of electricity, payments were not, however, being made fully. The PSALM was initially designated as the default wholesale supplier (DWS) in order to settle quantities that are not being paid in the market. In short, it was the government who initially carried the burden of the inefficiencies of non-paying customers.

23 Decision dated 20 June 2006, ERC Case No. 2006-007RC, pp. 39-40.

There was no policy of disconnection at the high voltage given that the NGCP had contracts with distribution utilities, directly connected customers, and generation companies for the use of their wires. It is only when the transmission wheeling charges are not paid that NGCP earns the right to disconnect based on their contract. Addressing this gap, the DOE anchored its policy on Section 2.2.4.2 of the WESM Rules which is in turn anchored on the gross pool and mandatory nature of the WESM.

The issuance of the disconnection policy upped the consciousness and accountability of electric cooperatives and private distribution utilities for payments.

IN TERMS OF THE NATURE OF THE OPERATOR – PRIVATE AND INDEPENDENT

The unbundling of the electric power industry and the privatization of the generation and transmission sector necessitates a neutral venue to allow the trading of electricity. The EPIRA envisioned this to be the WESM. The goal of equitable distribution of opportunities, income, and wealth is achieved through a market where a level-playing field is ensured.

Concomitantly, a neutral venue must be operated by an independent operator. Section 30 of the EPIRA provides:

> "The wholesale electricity spot market shall be implemented by a market operator in accordance with the wholesale electricity spot market rules. The market operator shall be an autonomous group, to be constituted by DOE, with equitable representation from electric power industry participants, initially under the administrative supervision of the TRANSCO. The market operator shall undertake the preparatory work and initial operation of the wholesale electricity spot market. Not later than one (1) year from after the implementation of the wholesale electricity spot market, an independent entity shall be formed and the functions, assets and liabilities of the market operator shall be transferred to such entity with the joint endorsement of the DOE and the electric power industry participants. Thereafter, the administrative supervision of the TRANSCO over such entity shall cease."

Pursuant to the DOE mandate to establish the WESM, PEMC was incorporated in 2003, or two years after the effectivity of the EPIRA. This was in preparation for the independent entity to take over the functions, assets, and liabilities of the market operator initially under the supervision of TRANSCO. The market operator was first designated under Department Order No. 2003-06-006 as within the organizational framework of TRANSCO. In 2004, this unit moved out of TRANSCO and was incorporated in the organizational structure of PEMC. Despite this, however, PEMC was not yet declared as the independent entity by the DOE owing to the need to define the word "independent". In 2011, the DOE adopted the recommendation of the ADB that "independent" means independent of the stakeholders and of the government. According to the Asian Development Bank (ADB), this interpretation is consistent with the model adopted in various electricity market jurisdiction where the board of the market operator is independent of the electric power industry participants and of the government. Further, it said, it is supported by the various provisions of the EPIRA using the term "independent". In fact, Rule 11 Section 3 of the EPIRA Implementing Rules and Regulations (IRR) expressly states that the electric power industry participants will not have any interest, direct or indirect, in the Independent Market Operator (IMO).

The need for the market operator to be independent is aligned with the principle of allowing a neutral venue for the trading of electricity. While every electric power industry participant has an interest in the spot market, not one sector should be allowed to monopolize it. Even the

government should not have a direct hand in it consistent with the philosophy of the mixed economy that the 1987 Constitution enshrined.

IN TERMS OF RELATION TO THE GOVERNMENT - ARM'S LENGTH FROM THE GOVERNMENT

The Policy/Rule Maker

The WESM Rules is a DOE Circular. It was first issued on June 28, 2002 as Department Circular No. DC2002-06-003 and signed by then Secretary Vincent Perez attaching thereto the Joint Endorsement by the electric power industry participants. This finds basis in Section 30 of the EPIRA which states in part:

> "Jointly with the electric power industry participants, the DOE shall formulate the detailed rules for the wholesale electricity spot market. xxx"

The reason for the circularization of the WESM Rules was articulated by Cong. Fuentebella during the deliberation of the EPIRA on April 12, 2000, to wit:

> "REP. BARBERS. Thank you, Madam Speaker, Your Honor.
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> With regards with the wholesale electricity spot market participants – because one of the provisions which I forgot which section, states that DOE and the electricity spot market participants which I suppose are members of the industry would be the one to formulate rules, guidelines and the policies as far as the dispatch is concerned. I would like to be clarified on that, Your Honor, Madam Speaker, because…
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> REP. FUENTEBELLA. Well, the practice really is, there should be an agency of government that should, more or less, supervise the aspect on formulating the rules on this wholesale electricity spot market but this involves, nonetheless, the industry participants because they are the ones that will be affected – or they are the players in the game so to speak such that they will have to decide how it shall be done, in what way we can come up with a good balance and it will be drafted by the DOE always together with the industry participants which shall be part of the public hearing, consultation process in the formulation of the IRRs."[24]

The rules change process of the WESM strikes a balance between the right of the electric power industry participants to discourse and debate on the evolution of the market and the authority of the DOE to govern it at arm's length. It allows the spot market to flourish on its own and at the same time give the government the final authority to determine its direction. This is the very essence of a partnership between the government and the private sector.

The rules change process is being handled by a Rules Change Committee (RCC), a committee under the umbrella of the WESM composed of the electric power industry participants. The RCC is a recommendatory body to the PEM Board which is also currently composed of the stakeholders. After approval, the proposal is submitted to the DOE for promulgation. From 2006 to the present, 30 Department Circulars were issued to amend the WESM Rules. All these went through a meticulous process of deliberation among the stakeholders with the DOE finally promulgating them.

24 EPIRA Plenary Deliberations, March 15, 2000, Legislative Archive Section InfoPack, Part 13, pp. 2760-2761.

This system is no different from other electricity market jurisdictions where the rules of the market evolve through a participative process.[25]

The Regulator/Enforcer

Section 2 (j) of the EPIRA declared it a policy to "establish a strong and purely independent regulatory body and system to ensure consumer protection and enhance the competitive operation of the electricity market." The ERC is the successor of the Energy Regulatory Board (ERB) created under Executive Order No. 172 in 1987. Similar to the ERB, the ERC is directly under the Office of the President.

The ERC enforces the WESM Rules issued by the DOE. This is pursuant to Section 42 of the EPIRA. To quote,

> "(c) Enforce the rules and regulations governing the operations of the electricity spot market and the activities of the spot market operator and other participants in the spot market, for the purpose of ensuring a greater supply and rational pricing of electricity."

The ERC's role in the enforcement of the WESM Rules issued by the DOE has been the subject of much debate in the past years. While the delineation might seem clear, its application remains a challenge. For one, the WESM Rules contain the market pricing methodology which is subjected to ERC approval. Second, there are certain market framework principles that have likewise been subjected to ERC evaluation.

This appears to have already been a concern in June 2006. At that time, the DOE issued Department Circular No. DC2006-01-0002 entitled "On the Mandate and Responsibility of the Department of Energy over the Wholesale Electricity Spot Market and the Authority of the Philippine Electricity Market Corporation in relation to the Preparation, Adoption, and Filing for Approval of the Price Determination Methodology". In this circular, the DOE specified that the PDM is expressed in "a series of equations or mathematical algorithm that constitute the Market Dispatch Optimization Model (MDOM)" which should adhere to the market design and features and principles contained in the WESM Rules particularly WESM Rules 3.2 to 3.10. Thus, it was effectively saying that solely the MDOM will be subjected to ERC approval and that its design principles should not be changed. Finally, the DOE provided in Section 4 thereof, that it shall "retain overall responsibility for ensuring that the market design and structure, as embodied in the WESM Rules, shall achieve the objectives of the wholesale electricity spot market xxx."

The ERC did not fully agree with this delineation. In its Decision dated 20 June 2006 in ERC Case No. 2006-007RC, it said that it will not be allowed to be limited by the DOE Circular. To quote,

> "As a preliminary to the instant application, PEMC relies on the Department of Energy (DOE) Circular No. 2006-01-0002 which allegedly clarifies the scope of the PDM and the extent of the DOE's and PEMC's authority over the WESM. xxx
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> xxx
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> Said Circular attempts to define the limits of the authority granted by the EPIRA to the Commission to pass judgment on the PDM. In the instant application, PEMC asserts that

25 Examples of electricity markets with a consultative rules change process are: New Zealand Electricity Market, California Electricity Market, Australia National Electricity Market, Ontario Electricity Market.

the '[t]he PDM was developed based on the principles and processes set out in WESM Rules clauses 3.2 through 3.10, inclusive. In developing the final version of the PDM, PEMC was also guided by DOE Circular 2006-01-0001.' xxx

The application likewise states that the PDM consists of various principles and procedures, which are set forth primarily in clauses 3.2 through 3.10 and Appendix A of the WESM Rules, and expressed in corresponding mathematical formula or algorithm, which in turn are embodied in the MDOM of the WESM. The said interpretation attempts to equate the pricing methodology, processes and principles solely to the MDOM or the market clearing algorithm.

The Commission does not agree with such interpretation as it ignores the broad regulatory authority vested upon the Commission as an independent quasi-judicial and quasi-legislative regulating body. The law must not have intended the Commission to be merely consigned to simply approving the MDOM or the market clearing algorithm alone. Such argument is simply untenable since the MDOM or the market clearing algorithm is only a component of the entire set of rules and procedures by which energy and reserve transactions in the WESM will be scheduled and priced. xxx

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The PEMC maintains that the MDOM embodies the PDM. On the contrary, it is the opposite, the MDOM forms part only of the entire PDM which is evident under the definition adopted by the WESM Rules of the MDOM:

> Market Dispatch Optimization Model: The optimization model which contains the mathematical algorithm approved by the PEM Board to be used for the purposes of determining dispatch schedule and energy prices, and preparing market projections based on the price determination approved by the ERC.

The PDM encompasses all other principles referred to by Sections 3.2 to 3.10 of the WESM Rules. The application for approval of the PDM is not limited to the provision of Section 3.6 alone but refers to the entire set of principles, processes and procedures which led to the determination of the prices and dispatch quantities in the WESM.

The Commission, in the exercise of its mandate is guided by the state policy to 'ensure customer protection and enhance the competitive operation of the electricity market'. Consequently, relative to the approval of the PDM, the Commission shall evaluate the totality of the principles, processes and procedures for the determination of the prices and dispatch quantities in the WESM. The Commission shall not allow itself to be straightjacketed by the DOE's and PEMC's erroneous assertions." [26]

This apparent overlap in the functions of the DOE and ERC was initially solved through close coordination between the two agencies. In fact, the creation of the Tripartite Committee co-chaired by the DOE and ERC with PEMC as the third member shows the intention of the DOE and ERC to closely coordinate their actions.[27] Their first act was to impose the mitigating measure of an offer cap in the market recognizing that such is a pricing as well as a supply issue which are within their respective jurisdictions.

26 ERC Case No. 2006-007RC, Decision, pp. 33-35.
27 Joint Resolution No. 1 dated 2 June 2006.

The creation of the Tripartite Committee did not, however, preclude disagreements. In 2010, the DOE started its Visayas Supply Augmentation Auction Program (VSAAP) to address the supply issue in the Visayas. However, the approval of the pricing methodology to implement such program met challenges in the ERC. The case is now pending with the Supreme Court on the issue of the jurisdiction of the DOE and the ERC.[28] It is hoped that this case will clarify the intent of the law on the jurisdiction of both agencies.

Despite the debates and challenges, it cannot, however, be denied that the differences still brought out the beauty of the restructuring of the electric power industry. The WESM proceeded to implement the rules of the DOE and the approvals of the ERC and the then growing number of WESM participants contributed to the intelligent and dynamic discussion in the market. These discussions were injected into the DOE and ERC and contributed to their policy and regulatory decisions.

AN INDUSTRY THAT DOES NOT WORK IN SILOS; A MARKET THAT ENABLES

It is without a doubt that the EPIRA supported the economic goals of the 1987 Constitution. The privatization of the power plants allowed for more investments in the country and efficiency in their operation. Instrumental to that is the level-playing field created in the WESM for the trading of electricity as a commodity. Accountabilities were identified insofar as energy withdrawals and payments are concerned. Further, transmission and distribution line improvements were also made transparent and investor decision in power plant locations became easier. Energy supports the foundation of our economy and a secure and reliable energy supply allows a sustained increase in the production of the Filipino products.

It is therefore significant that with the entry of private investors in the electricity industry, the government is mandated to ensure the protection of the ordinary consumer. The mixed economy model allows the market forces to work but not without the oversight of the government. The balance between governance and commercial forces must be achieved.

The WESM model is indubitably the tool for both the government and private sector to achieve this balance. With transparency as the core of its existence, it is intended to support policy and regulation and encourage competition among the industry players. Unlike in the contract-based water utility and expressway concessions, the EPIRA model, specifically the WESM model, preserved the regulatory authority of the government while allowing a market framework where the electricity participants can intelligently trade. The rules for this trading are not static and can be amended based on the experience of market players themselves but again subject to the final decision of the DOE. Similarly, the behaviour of the participants is closely monitored by their peers and by the ERC.

With this framework, it is incumbent upon each participant, be it the private or the government, to work together. It is even more important that the government agencies involved in monitoring the market are capacitated and strengthened for the benefit of the public. As in any other system, house rules should be followed and violators should be sanctioned. This is basically the challenge of the DOE and the ERC in the fast-paced market. The full backing of the national government must therefore be given to them in order to ensure increased coordination and collaboration. With the changing times and technology, the WESM must be seen by the government as a tool for policy and regulatory development. The electricity industry cannot work in silos. Let the WESM be the enabling tool for the increased coordination and collaboration of the government and the private sector.

28 Department of Energy v. Energy Regulatory Commission, G.R. No. 201943.



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