MAG-AMAR-2016

ANNUAL MARKET ASSESSMENT REPORT

For the 2016 Billing Period

PHILIPPINE ELECTRICITY MARKET CORPORATION

MARKET ASSESSMENT GROUP (MAG)

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EXECUTIVE SUMMARY

This 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 2015 to 25 December 2016. 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.

For the period in review, noticeable growth in the WESM registered capacity was observed with the entry of 39 new generating units in the WESM, 29 of which were solar plants with corresponding registered capacity of 605.3 MW. By the end of the December billing month, the WESM registered capacity already stood at 17,475 MW, an increase of about 7.7 percent from the 16,227 MW recorded at the start of the January billing month.

Despite these increases, only an average of 10,659 MW was offered in the market during the 12-month period, accounting for about 63 percent of the total WESM registered capacity while about 27 percent remained unavailable during the year attributed to outage capacity and capacity not offered. Outage capacity averaged at 1,956 MW, while an average of 2,571 MW was attributed to capacity not offered. Meanwhile, allocation of ancillary services as scheduled by the System Operator (SO) to provide contingency and dispatchable reserves in the Visayas accounted for an average of 116 MW this year. The 650-MW Malaya plant which is reserved to run as must run unit (MRU) accounted for about 3 percent of the total registered capacity, averaging at 488 MW. Capacities of preferential and non-scheduled generation, which averaged at 1,239 MW accounted for 7 percent.

Effective supply levels increased by about 18.7 percent from an average of 9,190 MW in 2015 to 10,882 MW in 2016, while average demand rose by 9.3 percent from 7,795 in the previous year to 8,522 MW. Consequently, the resulting reserve margin index for 2016 showed that wide supply margin generally prevailed throughout the year, though tight supply and demand balance was noted during the second and third quarters. The reserve margin was mostly tight particularly in June, demonstrated by the resulting RMI of less than 10 percent occurring at a high of 60.3 percent. Tight supply and demand balance likewise manifested in April, May, July and August at 41.2 percent, 41 percent, 34.6 percent and 37.9 percent of the time during these months.

Outages continued to influence the level of available supply in the market, resulting in tight supply conditions at certain periods of the year. Nevertheless, outage capacity averaged at 1,956 MW in 2016, recording a modest 3.1 percent decline from last year’s 2,019 MW.

Outage capacity was relatively high during the first quarter when demand levels were at their lowest. Outage capacity averaged at a high of 2,265 MW in January, 2,230 MW in February and 2,214 MW in March, but decreased in April and May, averaging at 1,749 MW and 1,143 MW, with the resumption of operations of several plants that were on outage in the first quarter. Outage capacity rose to an average of 1,898 MW in June while demand was still at its peak. Said increase in outage capacity was mainly driven by the increase in the forced outage capacity involving coal plants. Outage capacity demonstrated a significant increase of about 50 percent in August, averaging at 2,573 MW, the highest monthly average outage capacity during the year. This was substantially influenced by the consecutive outages of major power plants particularly during the period 26 July to 01 August, which saw increasing events of unscheduled outages of several major power plants in the Luzon region. A steady decline in the level of outage capacity was recorded during the last quarter of the year, with monthly outage capacity averaging at 1,712 MW in October, then posting an increase at 2,041 MW in November, which reverted to an average of 1,799 MW in December.

Supply availability in the market is likewise influenced by the continued submission by generator-trading participants of capacity offers less than their respective maximum available capacity, as indicated by the persistently high level of capacity gap throughout the billing year. Following relevant provisions in the WESM Rules, these shall be subject to further investigation for possible non-compliance with the must-offer rule. Similar with the previous year, majority of the capacity gap in the market is attributed to hydro plants, which capacity gap averaged at 915 MW, and accounted for about 35.6 percent of the total capacity gap during the year. Year-on-year comparison of capacity gap levels showed a notable 9.7 percent rise in the level of capacity gap, averaging at 2,577 MW from 2,344 MW in 2015. Said increase can be attributed to the significant rise by about 205 percent in the level of capacity gap among natural gas plants from an average of 119 MW in 2015 to 365 MW this year.

Market prices averaged at PhP2,948/MWh, the lowest annual average price in the WESM, since the integration of the Visayas market in 2011. A decrease of about 23 percent was observed from last year's average price of PhP3,829/MWh, and a further decrease of about 39.9 percent from the average market price in year 2014 posted at PhP4,904/MWh. It is significant to note that since the previous year 2015, there had been no imposition of the secondary price cap. Notwithstanding, and despite the wider supply margins which were generally experienced in the market, price spikes were still observed in trading intervals which manifested tight supply conditions resulting from the unavailability of several plants, though these occurred less frequently when compared with the two previous billing years.

Market prices were at their highest in June, as monthly prices averaged at PhP4,693/MWh. The June billing month was marked with tight supply conditions, while electricity demand remained relatively high. Consequently, the narrow supply margin which prevailed during the month was accompanied by the increase in market prices which were highest during the year. Meanwhile, the August billing month recorded the highest outage capacity this year, resulting in higher market prices averaging at PhP4,047/MWh, and essentially demonstrating that market prices were essentially driven by the level of available supply in the market. Nevertheless, as supply availability increased in the months that followed, market prices likewise eased and went on a downward trend until yearend. This notwithstanding, price spikes above PhP30,000/MWh were still observed during the September and December billing months.

Coal plants dominated the list of 55 generating plants that qualified as price-setters within the range of PhP5,000/MWh and below, with more plants setting the price at this level during off-peak hours. Major coal plants from Luzon Sual CFTPP and Pagbilao CFTPP topped the list of off-peak price-setters, setting the price at PhP5,000/MWh and below at about 43.2 percent and 35.9 percent during the year. On the other hand, the price-setting plants during peak hours within the PhP5,000/MWh and below range set the price at a lower frequency. Sual CFTPP was the most frequent price-setter among 46 price-setting plants, posting its PSFI at about 15.4 percent across the year during peak hours, followed by oil-based plant Navotas DPP at 15.1 percent, San Lorenzo NGPP at 12.2 percent, Ilijan NGPP at 11.6 percent, Pagbilao CFTPP at 10.9 percent and Sta. Rita NGPP at 10.2 percent.

Meanwhile, price-setters within the higher price range of above PhP5,000/MWh to PhP10,000/MWh were mostly oil-based and hydro plants. Seventeen (17) oil-based plants dominated the list of 26 price-setters during off-peak hours, topped by Visayas plants PB 101 DPP and TPC (Carmen) DPP with PSFIs of 2.5 percent and 2.1 percent during the year. The list of 26 price-setting plants during peak hours across the year were likewise dominated by 17 oil-based plants, topped by Bauang DPP with a PSFI of 3.5 percent followed by Angat HEP with 2 percent.

Meanwhile, thirteen (13) out of the 20 price-setters within the range of above PhP10,000/MWh during peak hours were oil-based plants. The list, however, was topped by hydro plant Kalayaan PSPP which set the price at about 0.9 percent of the time during year 2016. On the other hand, 14 plants were able to set the price at the above PhP10,000/MWh range during off-peak hours in 2016. Ten (10) out of these are oil-based plants.

Forty-two (42) plants in Luzon and 22 plants in the Visayas became pivotal suppliers during the billing year. In Luzon, large generating plants Ilijan NGPP, Sual CFTPP and Sta. Rita NGPP topped the list of pivotal suppliers at about 44.9 percent, 42 percent and 38 percent of the time in 2016. On the other hand, Visayas geothermal plant Leyte A GPP was the most frequent pivotal supplier in the Visayas region with a PSI of about 21.8 percent followed by CEDC CFTPP, becoming pivotal at about 17.4 percent of the time. The frequency by which generating plants became pivotal this year rose significantly during the June and August billing months, which were the same months marked with tight supply and demand balance. It was also observed that the May and April billing months likewise posted a relatively higher level of pivotal supply consistent with the tight reserve margin index during these months.

In terms of offer pattern, Luzon geothermal plants had the lowest offer prices among all the plant types throughout the 12-month period, with all of its capacity offers priced at PhP0/MWh and below. Meanwhile, Visayas geothermal plants submitted 80.2 percent of its offers at prices PhP0/MWh and below while 20.9 percent were priced above PhP0/MWh to PhP5,000/MWh. On the other hand, Luzon coal plants priced 44.9 percent of its capacity offers at above PhP0/MWh to PhP5,000/MWh, while 53.5 percent were priced at PhP0/MWh and below. Visayas coal plants recorded relatively lower offer prices across the billing year, with about 70.3 percent of its offers priced at PhP0/MWh and below.

Luzon oil-based plants submitted the highest offer prices among all plant types, with 38.3 percent of its offers priced above PhP10,000/MWh to PhP20,000/MWh. An equally high 36.1 percent were prices attributed to PhP10,000/MWh and below, 11.7 percent of which were above PhP5,000/MWh to PhP10,000/MWh. 17.2 percent of the remaining offers were priced even higher, at above PhP20,000/MWh to PhP30,000/MWh, while 8.5 percent were priced at PhP30,000/MWh. Visayas oil-based plants likewise offered its capacity at high prices. The bulk of its capacity were offers submitted at prices above PhP5,000/MWh to PhP10,000/MWh while 14.9 percent were capacity offers priced at above PhP10,000/MWh to PhP20,000/MWh. Meanwhile, 1.1 percent were offers submitted at prices above PhP20,000/MWh to PhP30,000/MWh and 7.1 percent were priced above PhP30,000/MWh.

About 28 percent of the offers of hydro plants were priced at PhP0/MWh and below, while 14.8 percent were capacity offers above PhP0/MWh to PhP5,000/MWh, and 43.7 percent were offer prices above PhP5,000/MWh to PhP10,000/MWh. Meanwhile, another 5.5 percent were offers at above PhP10,000/MWh to PhP20,000/MWh and another 4.1 percent were capacity offers attributed at above PhP20,000/MWh to PhP30,000/MWh. Lastly, the remaining 3.9 percent were capacity offers above PhP30,000/MWh. Lastly, offer prices of natural gas plants were relatively lower when compared with other plant types, with 73.3 percent of its capacity offers priced at PhP0/MWh and below.

The share of the four largest groups in terms of registered capacity continued to dominate the market system-wide throughout year 2016. San Miguel Corporation (SMC), First Gen Corporation (FGC), Aboitiz Power (AP) group, and Power Sector Assets and Liabilities Management Corporation (PSALM) took a combined market share averaging at 62.8 percent in 2016. With the exception of FGC, all three groups registered lower market shares this year as the number of new market players increased.

The market was moderately concentrated, with indications that market concentration levels generally improved beginning the second quarter of the year influenced in part by the entry of a substantial number of new smaller players and groups in year 2016.

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I. INTRODUCTION

This 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 2015 to 25 December 2016. 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.

II. ELECTRICITY DEMAND

A. Demand[1] Characteristics

1. Demand Summary

Electricity demand continued to grow, demonstrating significant increases during the period as the WESM reached its 10th year from the start of the commercial operations in Luzon on 26 June 2006. Maximum demand was posted at 11,458 MW system-wide, following the peak demand in Luzon which went as high as 9,725 MW on 11 May at 1400H. The Visayas region similarly exhibited the same trend in maximum demand growth, peaking at 1,862 MW on 02 September at 2000H. Maximum demand levels in both Luzon and Visayas grew their highest this year when compared to previous years, with Luzon obtaining an increase of 10.2 percent from 8,824 MW in 2015, while maximum demand levels in Visayas grew by 10.6 percent from previous year's 1,684 MW. System-wide, maximum demand levels increased by 10.8 percent from 10,337 MW in 2015.

In terms of average demand, year-on-year average demand growth of 9.2 percent was attained system wide, reflecting the noteworthy rise in regional demand levels in 2016. Luzon demand grew by 8.5 percent from an average of 6,623 MW in 2015 to 7,195 MW, one of the highest annual growth rate in the region in ten years. Visayas demand grew even higher, by 13.3 percent, from an average of 1,172 MW in 2015 to 1,328 MW, the highest growth rate in the region since the Visayas integration in the WESM on 26 December 2010.

The increase in maximum demand levels this year surpassed the peak demand growth rate forecast of the Department of Energy (DOE), which pegged annual regional demand growth rates at 4.4 percent in Luzon (from forecasted peak demand level of 9,074 MW to 9,473 MW), and 5.5 percent in Visayas (from 1,861 MW to 1,956 MW).

The robust growth of the economy, indicated by the growth in the country's annual gross domestic product (GDP)[2] by 6.8 percent from 5.8 percent in 2015[3] could have driven the notable rise in electricity demand levels this year. The National Economic and Development Authority (NEDA) underscored that the Philippine economy was the fastest growing among major emerging Asian economies, citing the country's highest quarterly GDP growth rate of 7.1 percent in the third quarter of 2016 as the highest in Asia during the period – even higher than China's 6.7 percent in the same quarter[4]. Additionally, it is also worth noting that year 2016 is an election year.

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[1] The demand is equal to the total scheduled MW of all load resources for each respective region plus losses.
[2] The GDP is the basic measure of a country's economic performance. It is defined as the total value of goods produced and services rendered in a given period.
[3] Philippine Statistics Authority
[4] https://business.inquirer.net/219732/philippine-economy-grows-fastest-in-asia#ixzz4YFpkzugk

Figure 1. Annual Demand Summary – Luzon

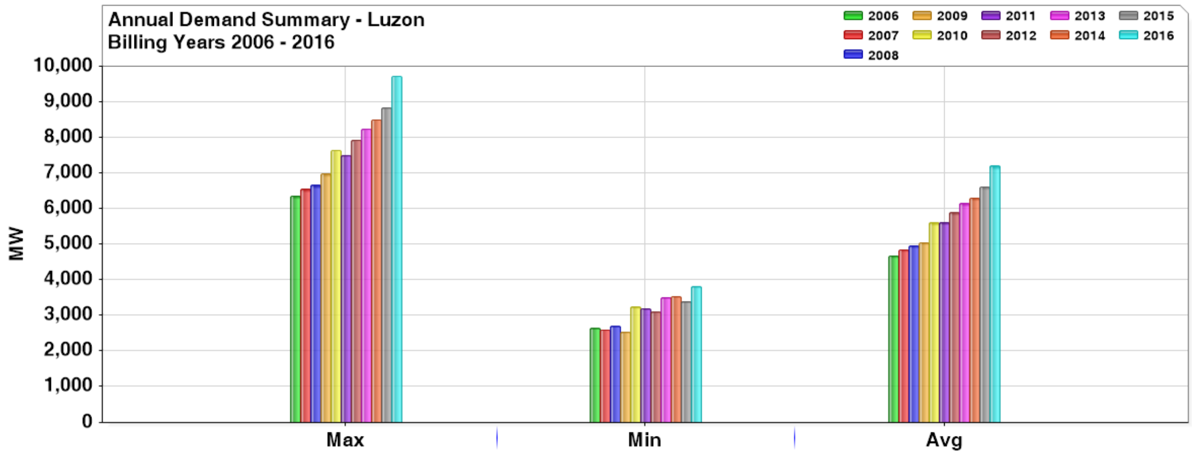


Figure 2. Annual Demand Summary – Visayas[5]

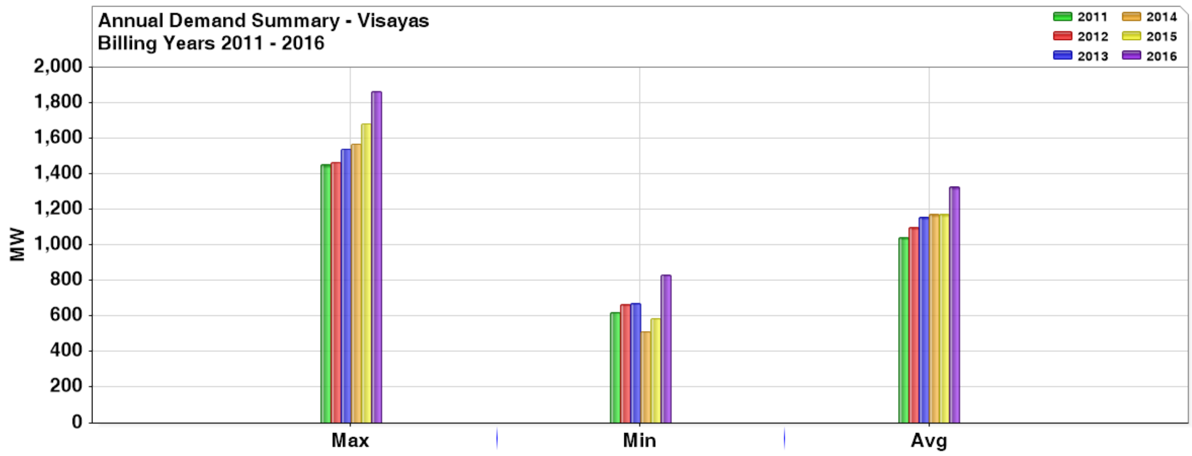


Table 1. Annual Demand Summary – Luzon

	Annual Demand Summary (MW) - Luzon										
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Max	6,361	6,553	6,658	6,993	7,644	7,485	7,921	8,232	8,497	8,824	9,725
Min	2,638	2,603	2,697	2,534	3,236	3,194	3,104	3,506	3,544	3,392	3,817
Avg	4,678	4,854	4,960	5,053	5,600	5,615	5,895	6,143	6,307	6,623	7,195

Table 2. Demand Summary – Visayas

	Annual Demand Summary (MW) - Visayas					
	2011	2012	2013	2014	2015	2016
Max	1,452	1,463	1,540	1,569	1,684	1,862
Min	621	665	673	514	589	833
Avg	1,042	1,099	1,157	1,172	1,172	1,328

[5] For this Annual Report, hourly demand on 08 November 2013 beginning 0100H was excluded from the calculation of the 2013 annual demand, following the extremely low demand levels that day due to the devastation brought about by super typhoon Yolanda in the region. It can be recalled that the Energy Regulatory Commission (ERC) declared partial market intervention which affected the Visayas from 08 November 2013 at 1500H to 25 March 2014 at 2400H, due to the destruction of the Visayas power system brought about by typhoon Yolanda.

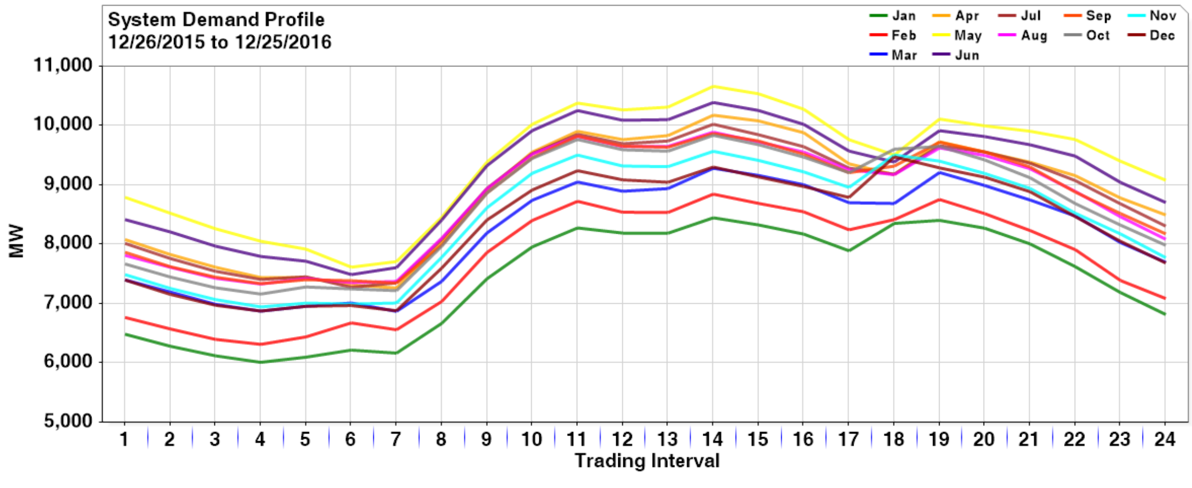
2. Demand Profile[6]

The system-wide demand profile illustrates that the pattern of electricity demand in a 24-hour period is practically the same for all billing months, regardless of seasonal or temperature changes across the year.

System hourly average demand generally peaked from 1000H to 2100H, reaching the highest average peak at 1400H, at 9,687 MW across the year. The highest average monthly peak demand was posted at 10,662 MW during the May billing month. Evening peak demand was generally posted at 1900H, except in January, October, November and December, when evening demand peaked earlier at 1800H, as noticeably shown in the Figure below. This pattern follows the earlier sunsets[7] which usually accompanied the cooler months of the year, as well as the Christmas and New Year festivities associated during these months. On the other hand, system-wide demand off-peak hours were usually observed from 0100H to 0900H and 2200H to 2400H.

The demand profile likewise shows the comparison of monthly average demand levels, which, similar to previous years, exhibited a certain level of predictability and seasonal pattern. From the low demand season in the first quarter, demand peaked in the summer months from April to June. Thereafter, average demand levels remained almost flat for the remainder of the year. As anticipated, monthly system demand levels proved to be highest during the second quarter driven by the rising temperatures during the summer months. Consequently, the May billing month posted the highest average demand level at 9,361 MW, followed by the 9,148 MW average demand for June. On the contrary, the lowest monthly average demand was posted during the cooler months of January and February, averaging at 7,406 MW and 7,729 MW during these months.

Figure 3. Hourly System Demand Profile



Regional demand profiles for Luzon and Visayas demonstrate the difference in the type of end-consumers that dominate each region. In Luzon, demand picked-up at 1100H in the morning averaging at 8,064 MW, but reached its maximum at 1400H in the afternoon, when bulk of the electricity requirement of commercial and industrial end-consumers is highest. At 1400H, Luzon demand averaged at 8,174 MW across the year, with May posting the highest hourly average demand level at 9,011 MW. May likewise obtained the highest monthly average demand level in Luzon at 7,911 MW, while the lowest monthly average demand was posted in January and February, at 6,224 MW and 6,540 MW. Unsurprisingly, Luzon

[6] Demand Profile illustrates monthly variation of average hourly demand over the course of a 24-hour period
[7] https://www.wunderground.com

mirrored the system-wide demand profile, considering that the region accounted for about 84 percent of the total demand in the market in 2016. As such, the system-wide demand profile followed the demand peak and off-peak hours observed in the Luzon grid.

On the other hand, the Visayas demand profile denotes that demand peak hours in the region were generally observed from 1800H to 2100H, reaching its highest at 1900H across all billing months, with the exception of October, November and December, when average demand peaked at 1800H, coinciding with the much earlier sunsets during these months of the year. Notwithstanding, the highest hourly demand level was posted at 1900H in May, averaging at 1,668 MW. This illustrates that majority of the end-consumers in the region are residential consumers, with higher demand requirement during the evening. Monthly average demand levels in the Visayas were relatively higher during the summer, with the May billing month posting the highest monthly demand at an average of 1,541 MW. Meanwhile, the January and February billing months posted the lowest monthly average demand levels at 1,182 MW and 1,189 MW, respectively.

Average demand levels were also noted to have increased on an hourly basis, system-wide and regionally, as shown in the Tables below.

Figure 4. Hourly Demand Profile – Luzon

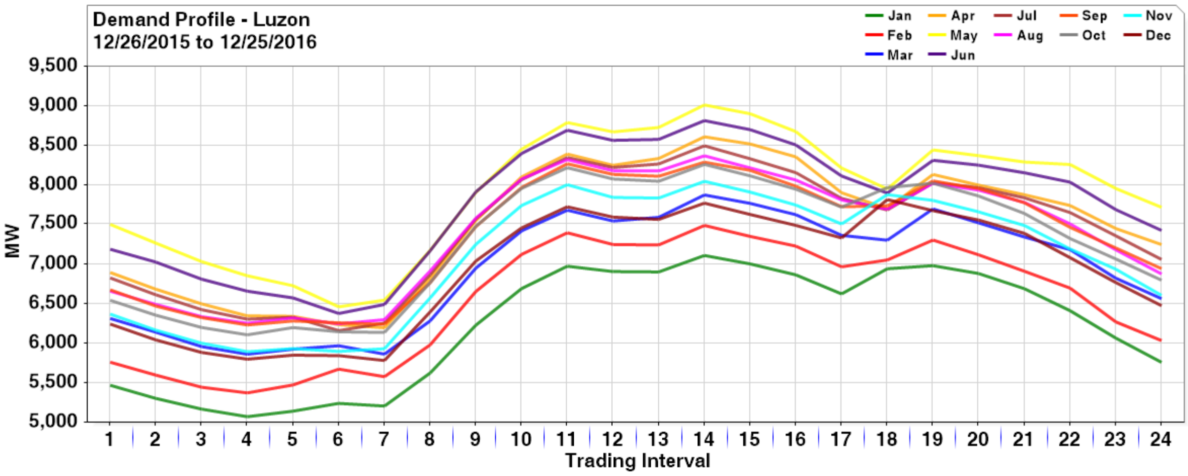


Figure 5. Hourly Demand Profile - Visayas

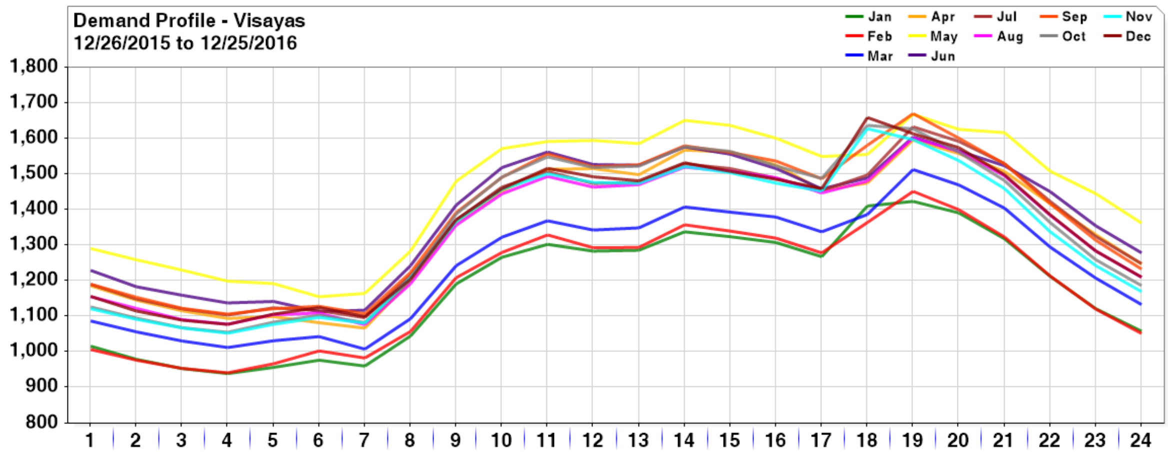


Table 3. Hourly Demand Profile – 2016

	Average Demand (MW) by Trading Interval (MW) - 2016																								
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Avg
Sys	7,684	7,457	7,260	7,129	7,174	7,127	7,111	7,790	8,643	9,220	9,547	9,393	9,402	9,687	9,545	9,352	9,016	9,147	9,454	9,294	9,070	8,740	8,335	7,992	8,522
Luz	6,537	6,346	6,175	6,062	6,090	6,039	6,040	6,609	7,298	7,786	8,064	7,934	7,944	8,174	8,048	7,882	7,590	7,633	7,871	7,757	7,596	7,374	7,062	6,792	7,195
Vis	1,147	1,111	1,084	1,067	1,084	1,088	1,070	1,181	1,345	1,435	1,482	1,458	1,457	1,513	1,497	1,470	1,428	1,513	1,583	1,537	1,474	1,367	1,274	1,199	1,328

Table 4. Hourly Demand Profile – 2015

	Average Demand (MW) by Trading Interval (MW) - 2015																								
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Avg
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	8,662	8,906	8,765	8,568	8,221	8,380	8,728	8,561	8,336	8,042	7,598	7,230	7,804
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	7,364	7,563	7,443	7,275	6,974	7,040	7,314	7,192	7,031	6,838	6,488	6,188	6,631
Vis	996	964	940	928	949	957	943	1,055	1,207	1,281	1,327	1,295	1,296	1,341	1,320	1,292	1,247	1,340	1,414	1,368	1,305	1,204	1,110	1,042	1,172

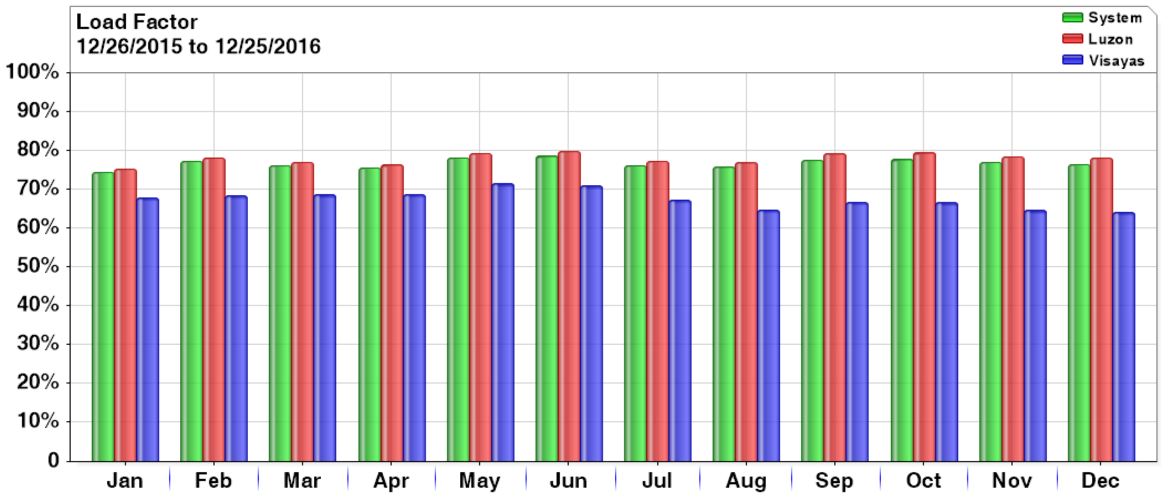
3. Load Factor[8]

The system-wide load factor in 2016 ranged from a low of 74.5 percent in January to a high of 78.2 percent and 78.5 percent in May and June, demonstrating that the efficiency of energy usage across the year is almost uniform at above 70 percent. Regional load factors reflect the same trend, with Luzon recording its highest load factor at 79.3 percent, 79.7 percent and 79.4 percent in May, June and October, respectively, and the lowest, at 75.2 percent in January.

Though at a lower rate, the monthly load factor trend in Visayas nevertheless reflected the trend system-wide, with May and June posting the highest load factors at 71.5 percent and 71 percent, respectively. However, load factor in Visayas was lowest in December at 64.2 percent. Overall, the system-wide load factor averaged at 71.4 percent in 2016 while Luzon and Visayas load factors averaged at 72.4 percent and 63.5 percent, respectively.

Annual load factors in the previous year were posted within the same range, averaging at 72.4 percent system-wide, while Luzon and Visayas load factors averaged at 72.5 percent at 62.6 percent, respectively. It is noted, however, that monthly load factors in the Visayas were generally lower in year 2016 than in 2015, particularly during the January and February and June to December billing months.

Figure 6. System Load Factor



[8] 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. For this Annual Report, load factor is computed from the metered quantity of the energy withdrawn in 2016.

Table 5. Monthly Load Factor – 2016

	Load Factor (%) by Billing Month - 2016												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
System	74.5	77.2	76.1	75.6	78.2	78.5	76.1	75.7	77.5	77.6	76.9	76.5	71.4
Luzon	75.2	78.1	77.0	76.3	79.3	79.7	77.3	76.8	79.1	79.4	78.5	78.0	72.4
Visayas	67.9	68.5	68.7	68.8	71.5	71.0	67.3	64.8	66.8	66.7	64.6	64.2	63.5

Table 6. Monthly Load Factor – 2015

	Load Factor (%) by Billing Month - 2015												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	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

Over the course of six (6) years, from 2011 to 2016, system-wide load factors steadily figured between a low of 69.6 percent to a high of 71.4 percent. Luzon demonstrated slightly higher load factors, which closely ranged from 70.1 percent to 72.5 percent. On the other hand, load factors were lower in the Visayas region, ranging from 60.7 percent to 63.5 percent.

Note that the resulting load factor for years 2013 and 2014 were in part influenced by the destruction brought about by typhoon Yolanda to the Visayas grid following its onslaught on 08 November 2013, prompting the ERC's market suspension of the Visayas which was declared from 08 November 2013 to 25 March 2014. In addition, load factors in Luzon for the 2014 billing year was likewise partly influenced by the power system disturbance caused by typhoon Glenda in Luzon during the July 2014 billing month.

Figure 7. Historical Load Factor, 2011-2016

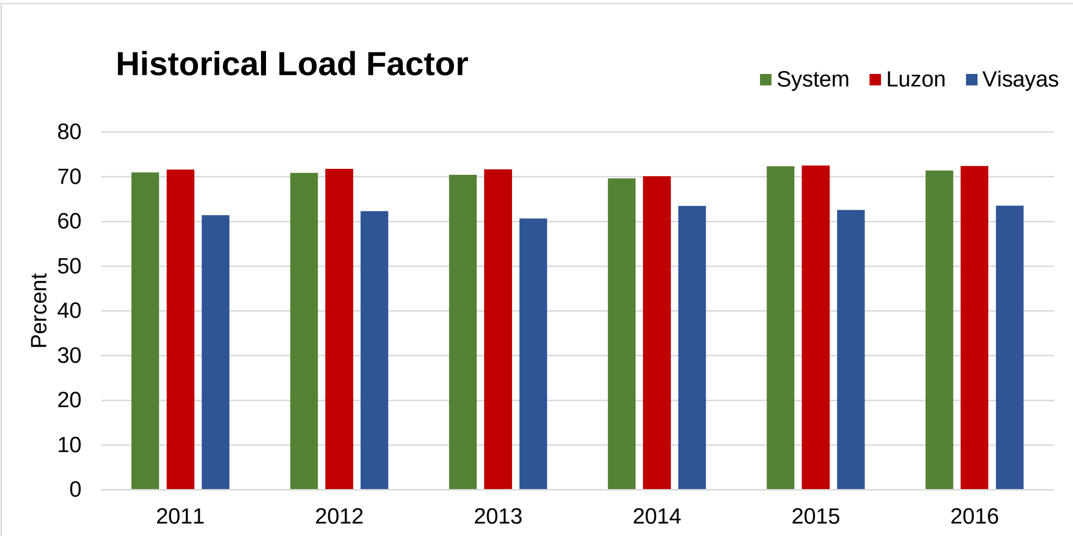


Table 7. Historical Load Factor – 2011-2016

	Annual Load Factor (%)					
	2011	2012	2013	2014	2015	2016
System	71.0	70.9	70.5	69.6	72.4	71.4
Luzon	71.6	71.7	71.7	70.1	72.5	72.4
Visayas	61.4	62.3	60.7	63.5	62.6	63.5

B. Load Forecast Variation[9]

For the duration of the 2016 billing year, it was observed that majority of the variation between the load forecasts in the ex-ante and the ex-post load were within +/-1 percent. Occurrences of under- and over- forecast events beyond +/-1 percent were also noted, though these were of lesser frequency across the billing months for both Luzon and Visayas.

In Luzon, about 58.9 percent of the total variations observed during the billing year ranged from +/-1 percent. The load forecast variations in the Visayas, on the other hand, were more spread out, as only 35.3 percent ranged from +/-1 percent. Load forecast variations between -5 percent to -10 percent in Visayas were also quite high, averaging at about 23.5 percent across the year. Significantly, as shown in Figure 8 below, about 61.6 percent of the Visayas load forecast in the ex-ante varied from the ex-post load by -5 percent to -10 percent during the September billing month.

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

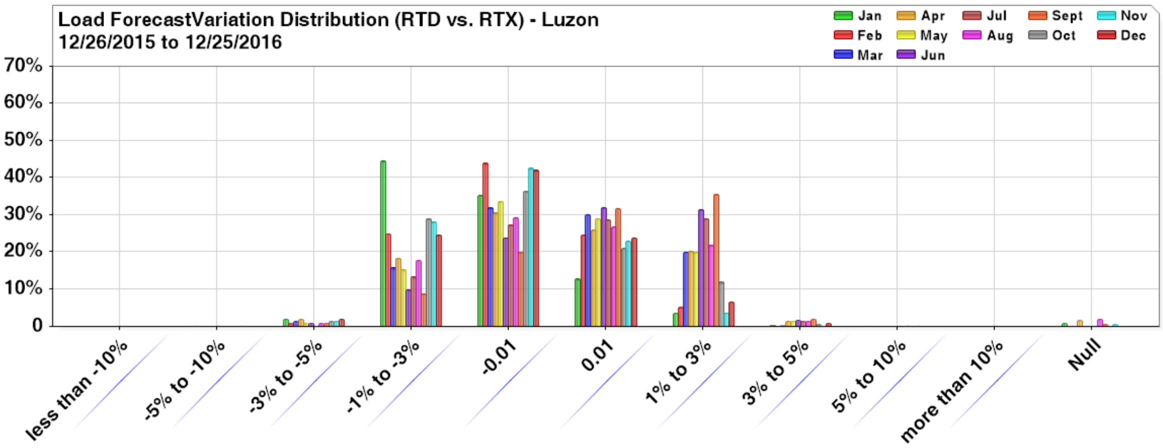


Table 8. Load Forecast Variation Distribution (Ex-Ante vs. Ex-Post) – Luzon

	Load Forecast Variation (%) Distribution (RTD vs. RTX) - Luzon, 2016												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
less than -10%	-	-	-	-	-	-	-	-	-	-	-	-	-
-5% to -10%	-	0.1	0.1	-	-	-	-	-	-	-	-	0.1	0.0
-3% to -5%	2.0	0.8	1.3	1.9	0.7	0.9	0.3	0.8	0.9	1.3	1.5	1.9	1.2
-1% to -3%	44.6	25.0	15.9	18.3	15.4	9.9	13.5	17.9	8.9	28.9	28.1	24.6	20.9
-1% to 0%	35.3	44.0	31.9	30.5	33.6	23.9	27.2	29.3	19.9	36.4	42.6	42.1	33.0
0% to -1%	12.9	24.6	30.2	25.9	29.0	32.0	28.8	26.9	31.9	21.0	23.0	23.9	25.8
1% to 3%	3.5	5.1	20.0	20.2	19.9	31.5	29.0	21.8	35.6	11.9	3.6	6.7	17.4
3% to 5%	0.5	0.3	0.4	1.5	1.3	1.7	1.3	1.5	1.9	0.6	0.3	0.7	1.0
5% to 10%	0.1	-	-	-	-	-	-	-	0.3	-	0.3	-	0.1
more than 10%	-	-	-	-	-	-	-	-	-	-	-	-	-
Null	0.9	0.1	0.1	1.7	0.1	-	-	1.9	0.7	-	0.7	-	0.5

Note: Results are null if either the ex-ante or the ex-post load forecast is null due to market intervention/suspension or if there was no ex-post run.

[9] 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.

Figure 9. Load Forecast Variation Distribution (Ex-Ante vs. Ex-Post) - Visayas

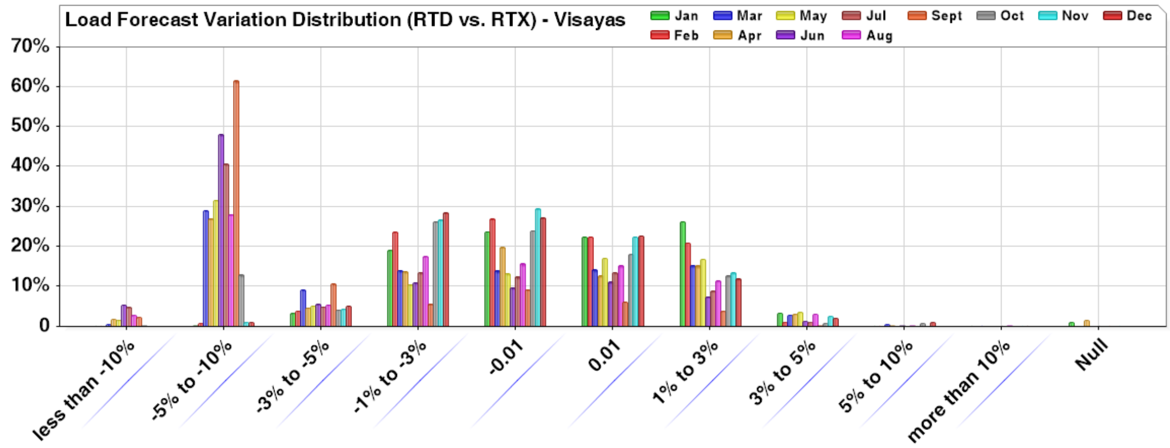


Table 9. Load Forecast Variation Distribution (Ex-Ante vs. Ex-Post) - Visayas

	Load Forecast Variation (%) Distribution (RTD vs. RTX) - Visayas, 2016												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
less than -10%	0.1	0.1	0.6	1.9	1.5	5.4	4.7	2.7	2.3	0.4	-	-	1.7
-5% to -10%	0.4	0.8	29.0	26.9	31.7	48.1	40.7	28.0	61.6	12.9	0.9	1.1	23.5
-3% to -5%	3.2	3.9	9.2	4.7	5.1	5.5	4.9	5.4	10.8	4.2	4.3	5.1	5.5
-1% to -3%	19.1	23.7	14.1	13.8	10.6	11.0	13.6	17.5	5.5	26.3	26.6	28.5	17.5
-1% to 0%	23.8	26.9	13.9	19.8	13.3	9.7	12.4	15.7	9.3	24.0	29.4	27.2	18.8
0% to -1%	22.4	22.4	14.2	12.8	17.1	11.2	13.6	15.3	6.2	18.1	22.4	22.8	16.5
1% to 3%	26.3	21.0	15.4	15.2	16.8	7.4	8.9	11.6	3.8	12.8	13.6	12.1	13.7
3% to 5%	3.4	0.9	2.9	3.0	3.5	1.3	1.0	3.1	0.4	0.7	2.4	2.1	2.0
5% to 10%	0.1	0.1	0.6	0.4	0.3	0.4	0.3	0.4	0.1	0.7	-	1.0	0.4
more than 10%	0.1	-	0.1	-	-	-	-	0.4	-	-	0.1	0.1	0.1
Null	0.9	0.1	-	1.6	0.1	-	-	-	0.1	-	0.1	-	0.3

Note: Results are null if either the ex-ante or the ex-post load forecast is null due to market intervention/suspension or if there was no ex-post run.

III. CAPACITY PROFILE

For the period in review, noticeable growth in the WESM registered capacity was observed throughout the billing year with the entry of 39 new generating units in the WESM. By the end of the December billing month, the WESM registered capacity already stood at 17,475 MW, an increase of about 7.7 percent from the 16,227 MW recorded at the start of the January billing month.

As shown in Table 11 on New Plants, notable increases during the year were observed on account of the entry of 29 solar plants with corresponding registered capacity of 605.3 MW. This comprised about 40.2 percent of the total 1,506.9 MW additional capacity which registered in the market during the year. In addition, additional capacity from coal plants totalled 435 MW, following the entry of new facilities under the SMC Consolidated Power Corporation, Palm Concepcion Power Corporation (PCPC), and the additional coal facility of Panay Energy Development Corporation (PEDC). On top of these, First Natgas Power Corporation registered its 414.1 MW natural gas plant during the year.

Despite these increases, only an average of 10,659 MW was offered in the market during the 12-month period, accounting for about 63 percent of the total WESM registered capacity while about 27 percent remained unavailable during the year attributed to outage capacity and capacity not offered. Outage capacity averaged at 1,956 MW, while an average of 2,571 MW was attributed to capacity not offered. These comprised about 12 percent and 15 percent, respectively, of the total registered capacity. Capacity not offered is subject to further investigation for possible breach of the Must Offer Rule.

Meanwhile, allocation of ancillary services as scheduled by the System Operator (SO) to provide contingency and dispatchable reserves in the Visayas[10] accounted for an average of 116 MW this year. The 650-MW Malaya plant which is reserved to run as must run unit (MRU) accounted for about 3 percent of the total registered capacity, averaging at 488 MW. Capacities of preferential[11] and non-scheduled generation, which averaged at 1,239 MW accounted for 7 percent. Significant growth in the registered capacity of preferential and non-scheduled generation by as much as 39 percent was recorded in March with the influx of registration of solar plants vying for accreditation under the Feed-in-Tariff (FIT) program.

Market intervention events were likewise noted within the year, as shown in the gaps in Figure 9. Details on these events are discussed in a subsequent section of this Report.

Figure 10. Capacity Profile

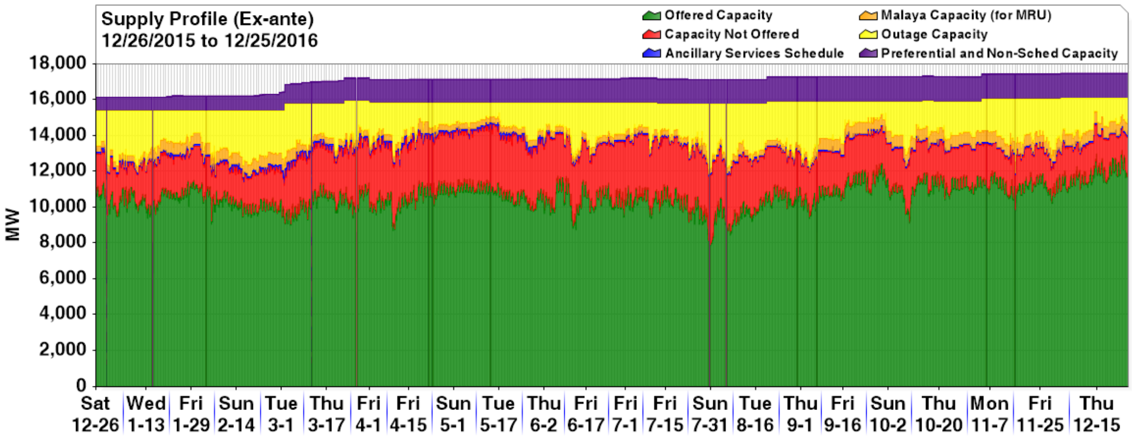


Table 10. Capacity Profile – System

	Capacity Profile (Average MW) - 2016, System													
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg	% of Reg Cap
Registered Capacity (End of Month)	16,227	16,315	17,215	17,143	17,149	17,155	17,134	17,287	17,292	17,292	17,449	17,475	17,475	
Offered Capacity	10,459	10,396	10,207	10,438	10,928	10,436	10,326	9,791	10,837	11,191	11,253	11,646	10,659	63
Outage Capacity	2,265	2,230	2,214	1,749	1,143	1,898	1,715	2,573	2,106	1,712	2,041	1,799	1,956	12
Capacity Not Offered	2,087	1,971	2,651	3,073	3,236	3,030	3,330	2,959	2,351	2,284	2,002	1,904	2,571	15
Ancillary Services Schedule	111	139	202	162	169	128	88	78	82	80	74	85	116	1
Malaya Capacity (for MRU)	461	650	459	384	355	350	350	366	523	650	650	650	488	3
Preferential and Non-Sched Capacity	744	826	1,149	1,288	1,303	1,320	1,365	1,370	1,376	1,378	1,379	1,381	1,239	7

[10] Central scheduling of energy and contracted reserve has yet to be implemented in the Visayas.
[11] Preferential capacity refers to the combined registered capacities of priority dispatch and must dispatch generating units.

Table 11. New Power Plants

New Power Plants - 2016					
Plant Type	Region	Market Participant Name	Node ID	Registration Effectivity Date	Registered Capacity (MW)
Battery	Luzon	Masinloc Power Partners Co. Ltd.	1MSNLO_BATG	02-Jul-16	10.0
Sub-Total (Battery)					**10.0**
Biomass	Luzon	Green Innovations for Tomorrow Corporation	1GIFT_G01	20-Jan-16	12.0
	Luzon	Aseagas Corporation	3LIAN_G01	20-Aug-16	7.3
	Luzon	Bicol Biomass Energy Corporation	3BBEC_G01	07-Sep-16	5.0
Sub-Total (Biomass)					**24.3**
Coal	Visayas	Palm Concepcion Power Corporation	8PALM_G01	23-Mar-16	135.0
	Visayas	Panay Energy Development Corporation	8PEDC_U03	19-Aug-16	150.0
	Luzon	SMC Consolidated Power Corporation	1SMC_G01	4-Nov-16	150.0
Sub-Total (Coal)					**435.0**
Hydro	Visayas	Sunwest Water and Electric Company 2, Inc.	8SUWECO_G01	04-Jan-16	8.0
	Luzon	Smith Bell Mini-Hydro Corporation	1SMBELL_G01	11-Nov-16	1.8
Sub-Total (Hydro)					**9.8**
Natural Gas	Luzon	First Natgas Power Corporation	3SNGAB_G01	02-Mar-16	414.1
Sub-Total (Natural Gas)					**414.1**
Oil	Visayas	Central Negros Power Reliability, Inc.	6CENPRI_U01	23-Mar-16	4.2
	Visayas		6CENPRI_U03	23-Mar-16	4.2
Sub-Total (Oil)					**8.4**
Solar	Luzon	Energy Development Corporation	1BURGOS_G03	20-Jan-16	2.7
	Luzon	YH Green Energy, Incorporated	1YHGRN_G01	20-Jan-16	14.5
	Luzon	PetroSolar Corporation	1PETSOL_G01	22-Jan-16	50.0
	Luzon	Solar Philippines Calatagan Corporation	3CALSOL_G01	22-Feb-16	50.0
	Luzon	RASLAG Corp.	1RASLAG_G02	23-Feb-16	13.1
	Luzon	Mirae Asia Energy Corporation	1MAEC_G01	01-Mar-16	16.3
	Luzon	Valenzuela Solar Energy, Inc.	2VALSOL_G01	03-Mar-16	8.5
	Luzon	Enfinity Philippines Renewable Resources Inc.	1CLASOL_G01	09-Mar-16	18.0
	Luzon	Absolut Distillers Inc.	3ADISOL_G01	10-Mar-16	1.6
	Luzon	SPARC-Solar Powered Agri-Rural Communities Corporation	1ZAMSOL_G01	10-Mar-16	5.0
	Luzon		1SPABUL_G01	15-Mar-16	1.2
	Luzon		1BTNSOL_G01	14-Mar-16	5.0
	Luzon	Bulacan Solar Energy Corp.	1BULSOL_G01	11-Mar-16	15.0
	Luzon	First Cabanatuan Renewable Ventures Inc.	1CABSOL_G01	15-Mar-16	9.1
	Luzon	Next Generation Power Technology Corp.	1MARSOL_G01	15-Mar-16	16.0
	Luzon	nv vogt Philippines Solar Energy Three, Inc.	1ARMSOL_G01	08-Apr-16	7.1
	Luzon	nv vogt Philippines Solar Energy Four Inc.	1DALSOL_G01	08-Apr-16	5.9
	Luzon	Jobin-SQM Inc.	1SUBSOL_G01	15-Apr-16	7.1
	Luzon	Bosung Solartec, Inc.	1BOSUNG_G01	22-Jun-16	1.0
	Visayas	Monte Solar Energy Inc.	6MNTSOL_G01	24-Feb-16	14.4
	Visayas	Helios Solar Energy Corporation	6HELIOS_G01	29-Feb-16	108.1
	Visayas	Negros Island Solar Power Inc.	6CARSOL_G01	01-Mar-16	27.2
	Visayas	Negros Island Solar Power Inc.	6MANSOL_G01	04-Mar-16	40.5
	Visayas	San Carlos Sun Power, Inc.	6SACSUN_G01	08-Mar-16	46.8
	Visayas	Silay Solar Power, Inc.	6SLYSOL_G01	08-Mar-16	20.0
	Visayas	Sulu Electric Power and Light (Phils.), Inc.	4SEPSOL_G01	15-Mar-16	45.0
	Visayas	Cosmo Solar Energy, Inc.	8COSMO_G01	25-May-16	5.7
	Visayas	First Toledo Solar Energy Corporation	5TOLSOL_G01	29-Jun-16	49.0
	Luzon	CW Marketing and Development Corporation	3HDEPOT_G01	4-Nov-16	1.5
Sub-Total (Solar)					**605.3**
Grand Total					**1,506.9**

IV. DEMAND AND SUPPLY

A. Demand[12] and Supply[13] Situation

Increasing demand trend was observed from January when demand levels were at their lowest during the year, until the summer months when demand started to pick-up. Demand was noted to have increased by as much as 8.3 percent in April and 5.6 percent in May, posting the highest monthly average demand for the 2016 billing year at 9,361 MW. Demand began to decline by about 2.3 percent beginning June and followed a decreasing trend until yearend, with demand ranging closely between 8,803 MW in July to 8,278 MW in December. Dip in demand levels across the year were generally attributed to the observance of national holidays which effectively influenced demand requirements. Noticeable dips in demand were noted on 26 December to 01 January following the Christmas and New Year holidays, on 24-25 March due to the observance of the Holy Week, and on 01-02 November due to the observance of All Saints Day.

Meanwhile, reserve schedule averaged at 740 MW during the year. Consequently, demand plus reserve schedule[14] recorded an average of 9,262 MW, with the May billing month recording the highest level of demand plus reserve schedule, averaging at 10,098 MW, and January, with the lowest for the year at 8,207 MW. The June billing month recorded the next highest level of demand plus reserve schedule at an average of 9,932 MW.

On the other hand, effective supply levels were low during the first quarter of the year, due to low supply availability. The lowest monthly effective supply level was recorded in January averaging at 10,181 MW. Effective supply started to increase notably in April by about 4.1 percent from 10,415 MW in March to 10,845 MW mainly driven by the drop in the outage capacity of major coal plants during the month, and by another 5.8 percent in May to an average of 11,477 MW, as demand levels rose following the seasonal demand increase in the summer months. However, supply declined by 5 percent in June at an average of 10,898 MW. This resulted in the narrow supply margin which averaged at 967 MW during the month, the lowest supply margin for the duration of the year. Supply levels dropped another 1 percent in July at 10,786 MW, and another 3.3 percent in August at 10,425 MW, following the surge in outage capacity that month which was the highest monthly outage capacity for the entire year. Supply margin consequently narrowed in August, averaging at 1,180 MW. Supply levels improved over the next succeeding months and went on an increasing trend beginning September, averaging at 11,005 MW to a high of 11,669 MW in December resulting in the wide supply margin which prevailed throughout the last quarter of the year.

Year-on-year comparison showed better supply and demand conditions this year than the previous year, recording an average increase in effective supply by about 18.7 percent from 9,190 MW in 2015 to 10,882 MW in 2016, while average demand rose by 9.3 percent from 7,795 in the previous year to 8,522 MW. Consequently, the market generally experienced wider supply margins this year, posting an increase of about 16.6 percent from the average supply margin of 1,386 MW in 2015 to 1,615 MW in 2016. Notwithstanding, particular incidents during which supply levels dropped were noted to have effectively resulted in the tightening of the supply margin and the increase in market prices, as will be discussed in the succeeding section on Market Price Outcome.

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[12] The system effective supply is equal to the offered capacity of all scheduled generator resources, nominated loading level of non-scheduled generating units and projected output of preferential dispatch generating units adjusted for any security limit and ramp rates. Scheduled output of plants on testing and commissioning, through the imposition of security limit by SO, are accounted for in the effected supply. Likewise included is the scheduled output of Malaya plant when it is called to run as Must Run Unit (MRU).

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

[14] With the implementation of the central scheduling and dispatch of energy and contracted reserves in Luzon beginning 22 December 2015, the level that the supply has to fill up is higher as it also has to sufficiently meet the hourly reserve schedule.

Figure 11. Demand and Effective Supply – System

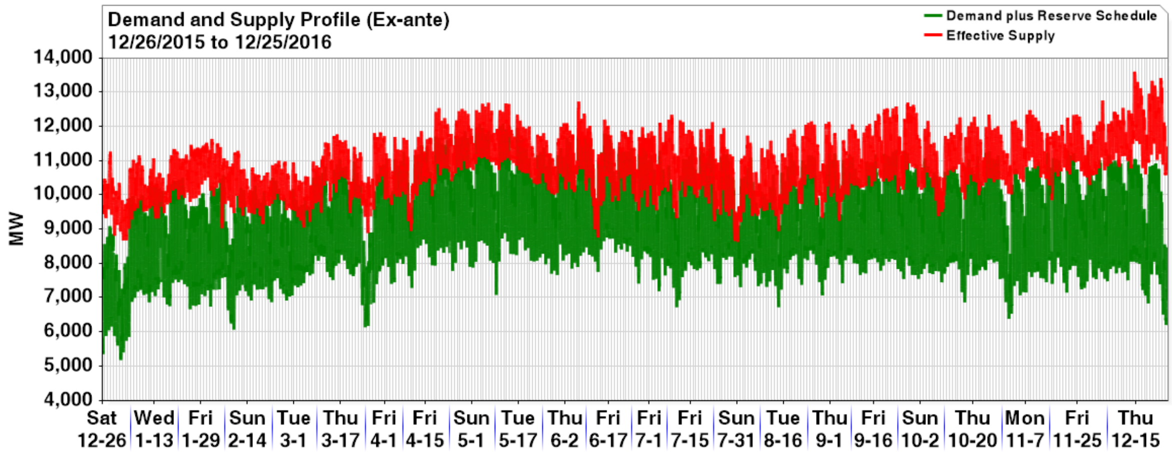

Table 12. Demand and Supply Summary – System, 2016

	Supply and Demand Summary (Average MW) - 2016, System												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
Demand	7,406	7,729	8,185	8,863	9,361	9,148	8,803	8,709	8,729	8,645	8,421	8,278	8,522
Reserve Schedule	801	889	802	700	736	784	622	514	697	674	791	868	740
Demand + R/S	8,207	8,618	8,987	9,563	10,098	9,932	9,425	9,223	9,426	9,318	9,212	9,146	9,262
Effective Supply	10,181	10,467	10,415	10,845	11,477	10,898	10,786	10,425	11,005	11,119	11,296	11,669	10,881
Supply Margin	1,974	1,849	1,426	1,293	1,379	967	1,361	1,180	1,570	1,801	2,074	2,523	1,616

Table 13. Demand and Supply Summary – System, 2015

	Supply and Demand Summary (Average MW) - 2015, System												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
Demand	6,528	7,051	7,462	7,741	8,381	8,407	7,952	8,027	8,106	8,058	8,119	7,696	7,795
Reserve Schedule	-	-	-	-	-	-	-	-	-	-	-	108	-
Demand + R/S	6,528	7,051	7,462	7,741	8,381	8,407	7,952	8,027	8,106	8,058	8,119	7,804	7,804
Effective Supply	8,175	8,147	8,625	9,264	9,589	9,253	9,137	9,477	9,913	9,633	9,466	9,566	9,190
Supply Margin	1,647	1,096	1,164	1,523	1,209	845	1,185	1,450	1,807	1,574	1,347	1,761	1,386

Meanwhile in Luzon, effective supply[15] averaged at 9,222 MW this year, an increase of about 19.4 percent from previous year's 7,726 MW while demand[16] increased by about 8.6 percent, from an average of 6,623 MW in 2015 to 7,195 MW this year. Supply margins were thus generally wider by about 17.6 percent this year, averaging at 1,288 MW, when compared to the previous year's 1,095 MW.

Mirroring the trend system-wide, demand levels in Luzon were lowest during the first few months of the year and started to follow an increasing trend beginning March, peaking at its highest in May and June at an average of 7,911 MW and 7,763 MW, respectively. Monthly average demand started to decline in July and continued to decrease until yearend. On the other hand, reserve schedule averaged at 740 MW, translating to an average of about 7,935 MW of demand plus reserve schedule[17] during the year. The highest levels of demand plus

[15] The regional effective supply is equal to the offered capacity of all scheduled generator resources, nominated loading level of non-scheduled generating units and projected output of preferential dispatch generating units in each region adjusted for any security limit and ramp rates. Scheduled output of plants on testing and commissioning, through the imposition of security limit by SO, are accounted for in the effected supply. In Luzon, effective supply likewise includes the scheduled output of Malaya plant when it is called to run as Must Run Unit (MRU).
[16] The regional demand is equal to the total scheduled MW of all load resources for each respective region plus losses.
[17] With the implementation of the central scheduling and dispatch of energy and contracted reserves in Luzon beginning 22 December 2015, the level that the supply has to fill up is higher as it also has to sufficiently meet the hourly reserve schedule.

reserve schedule in Luzon were posted in May at an average of 8,647 MW, and in June at an average of 8,547 MW.

On the other hand, effective supply levels were likewise low during the first quarter of the year but demonstrated notable increases in the summer months of April and May. Supply increased from 8,885 MW in March to 9,223 MW in April and 9,767 MW in May. However, supply levels dropped in June by about 5 percent to 9,282 MW. Supply also dropped by another 2.6 percent in July and a further 3.6 percent in August. Consequently, supply averaged at 9,040 MW and 8,717 MW during these months. Said drop in supply resulted in the narrowing of the supply margin from June to August to 735 MW, 976 MW and 831 MW, respectively. From September until yearend however, supply followed an increasing trend. The highest monthly supply level was recorded in December at an average of 9,803 MW, which in turn translated to the widest monthly average supply margin in Luzon during the year, posted at 2,011MW.

Supply levels in Luzon were notably augmented by the exchange of power between the Luzon and Visayas regions through the HVDC Interconnection. The 2016 billing year showed that Luzon is importing power from the Visayas majority of the time, particularly during off-peak hours. Nevertheless, the HVDC Interconnection was unavailable in 153 trading intervals from 0900H of 10 October to 16 October at 1700H due to the annual preventive maintenance of Ormoc HVDC Converter Station.

Figure 12. Demand and Effective Supply – Luzon

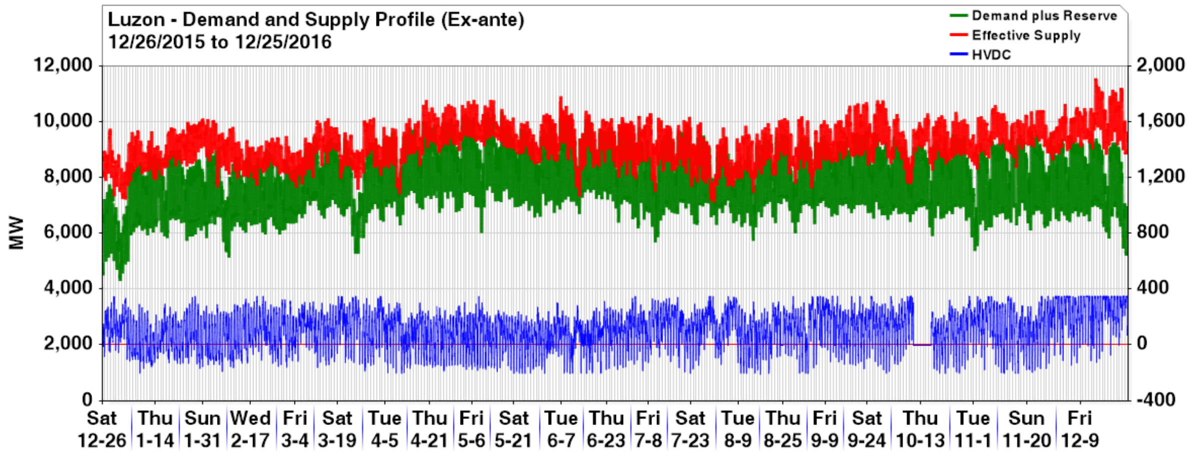

Table 14. Demand and Supply Summary – Luzon, 2016

	Supply and Demand Summary (Average MW) - 2016, Luzon												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
Demand	6,224	6,540	6,938	7,505	7,911	7,763	7,443	7,372	7,349	7,288	7,089	6,924	7,195
Reserve Schedule	801	889	802	700	736	784	622	514	697	674	791	868	740
Demand + R/S	7,025	7,430	7,740	8,206	8,647	8,547	8,065	7,886	8,046	7,962	7,880	7,792	7,935
Effective Supply	8,729	9,014	8,885	9,223	9,767	9,282	9,040	8,717	9,247	9,377	9,576	9,803	9,222
Supply Margin	1,704	1,585	1,145	1,029	1,120	735	976	831	1,201	1,415	1,697	2,011	1,288

Table 15. Demand and Summary – Luzon, 2015

	Supply and Demand Summary (Average MW) - 2015, Luzon												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
Demand	5,495	5,996	6,356	6,582	7,160	7,223	6,797	6,855	6,909	6,793	6,836	6,466	6,623
Reserve Schedule	-	-	-	-	-	-	-	-	-	-	-	108	-
Demand + R/S	5,495	5,996	6,356	6,582	7,160	7,223	6,797	6,855	6,909	6,793	6,836	6,575	6,631
Effective Supply	6,811	6,809	7,266	7,785	8,099	7,848	7,606	8,018	8,401	8,061	7,975	8,019	7,726
Margin	1,317	814	910	1,203	939	625	810	1,163	1,492	1,267	1,139	1,444	1,095

In the Visayas region, effective supply[18] levels increased by 13.5 percent from an average of 1,463 MW in the previous year to 1,660 MW this year. Meanwhile, demand[19] similarly increased by 13.3 percent from 1,172 MW in 2015 to 1,328 MW. Consequently, average supply margin increased by 14.3 percent from 291 MW in 2015 to 333 MW.

Seasonal demand patterns likewise influenced the demand trend in the region as demand rose from a low of 1,182 MW in January, the lowest monthly average demand during the year, to 1,247 MW in March. Demand further increased by 8.9 percent in April to 1,357 MW and a further 6.9 percent in May at 1,451 MW. Come June, demand declined slightly to 1,385 MW, and dropped further in July at 1,360 MW. Demand closely ranged within this level until yearend. On the other hand, effective supply levels were low during the first quarter, with the January billing month posting the lowest average effective supply at 1,182 MW. Effective supply in the region visibly increased during the summer months, particularly beginning March until May but dropped noticeably in June and August, averaging at 1,616 MW and 1,711 MW, respectively. In June, supply levels dropped by 5.4 percent from 1,710 MW in May attributed to the increase in outage capacity of Visayas coal and oil-based plants. Meanwhile, supply levels were lower by 2 percent in August from an average of 1,746 MW in July due to the simultaneous outages of major coal plants in the region. Effective supply levels then rose by 2.8 percent in September, averaging at 1,758 MW. Supply levels steadily increased until yearend, with December posting the highest monthly average supply level at 1,866 MW. In November, however, average supply dropped by 1.3 percent to 1,720 MW. Supply margins across the year averaged closely between 231 MW to 387 MW, but recorded its widest in December at an average of 511 MW.

This year, the HVDC power flow continued to be mostly directed towards Luzon. Visayas plants continued to export cheaper energy by as much as 350 MW through the HVDC Interconnection, particularly during off-peak hours.

Figure 13. Demand and Effective Supply – Visayas

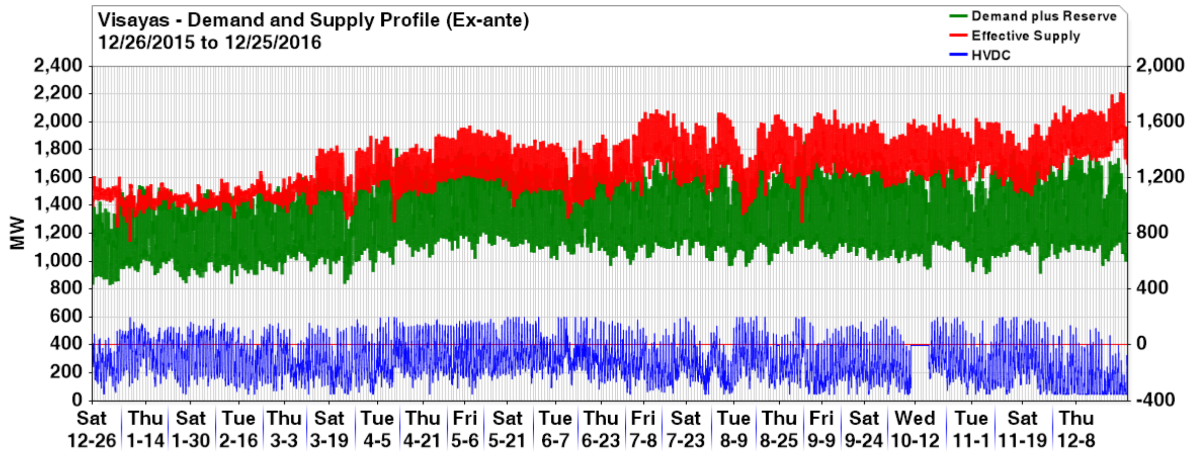

Table 16. Demand and Supply Summary – Visayas, 2016

	Supply and Demand Summary (Average MW) - 2016, Visayas												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
Demand	1,182	1,189	1,247	1,357	1,451	1,385	1,360	1,339	1,381	1,356	1,333	1,354	1,328
Effective Supply	1,452	1,453	1,530	1,622	1,710	1,616	1,746	1,711	1,758	1,742	1,720	1,866	1,660
Supply Margin	270	264	283	267	259	231	386	372	377	385	387	511	333

[18] The regional effective supply is equal to the offered capacity of all scheduled generator resources, nominated loading level of non-scheduled generating units and projected output of preferential dispatch generating units in each region adjusted for any security limit and ramp rates. Scheduled output of plants on testing and commissioning, through the imposition of security limit by SO, are accounted for in the effected supply.
[19] The regional demand is equal to the total scheduled MW of all load resources for each respective region plus losses.

Table 17. Demand and Supply Summary – Visayas, 2015

	Monthly Demand Summary (Average MW) - 2015, Visayas												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
Demand	1,033	1,057	1,106	1,159	1,220	1,184	1,155	1,172	1,199	1,265	1,283	1,230	1,172
Effective Supply	1,363	1,343	1,359	1,479	1,490	1,405	1,531	1,459	1,513	1,572	1,491	1,546	1,463
Supply Margin	330	287	254	320	270	221	376	287	314	308	209	317	291

B. Impact of Preferential and Non-Scheduled Generation to Demand and Supply

Impact to supply of preferential and non-scheduled generation was consistently observed throughout the billing year, with monthly averages ranging from 217 MW in January to 444 MW in December.

As shown in the Figure below, the contribution of preferential and non-scheduled generation to the level of supply noticeably increased beginning March, following the increased contribution of solar plants. In terms of the maximum contribution to supply, the same was posted in November and December at 859 MW and 876 MW, respectively. Meanwhile, the lowest maximum contribution was posted in January and February at 437 MW and 468 MW. For the rest of the 2016 billing months, the monthly maximum contribution of preferential and non-scheduled generation ranged from a low of 649 MW in June to 838 MW in October.

Figure 14. Impact of Preferential and Non-Scheduled Generation on Supply - System

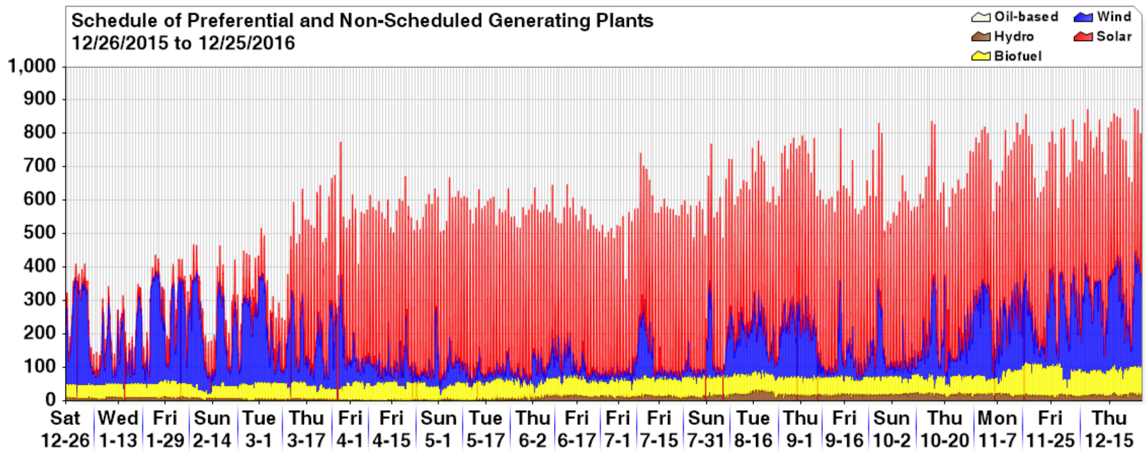

Table 18. Impact of Preferential and Non-Scheduled Generation on Supply – System

	Contribution to Supply of Preferential and Non-Scheduled Generation (Average MW) - System, 2016												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
Biomass	40	38	43	47	47	47	50	54	51	49	68	73	51
Hydro	9	9	6	3	4	13	13	19	17	19	18	17	12
Solar	13	28	83	141	157	138	137	135	146	141	140	135	116
Wind	154	188	148	75	48	45	47	102	100	89	167	219	115
Oil-based	-	-	-	-	-	-	0	1	1	1	1	1	0
Total	**217**	**262**	**279**	**266**	**256**	**243**	**249**	**311**	**316**	**300**	**394**	**444**	**295**

Preferential and non-scheduled generation also reduced the level of contestable demand in the market or the level of demand that is left for the generators to compete for. As shown in the Chart below, the monthly ratio of pmin to the demand ranged from 41.3 percent to 50.8 percent. With the preferential and non-scheduled generating units, the ratio increased by about 4 percent, further reducing the level of contestable demand.

Figure 15. Impact of Preferential and Non-Scheduled Generation on Total Pmin and Demand - System

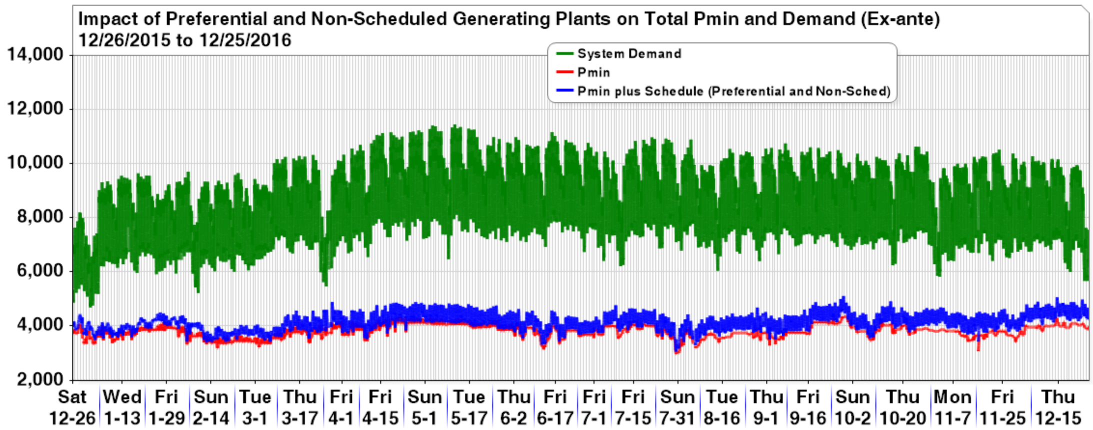

Table 19. Impact of Preferential and Non-Scheduled Generation on Total Pmin and Demand – System

	Percent of Demand - System, 2016												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
Pmin	50.8	47.3	44.7	44.8	44.1	41.4	44.1	41.3	44.0	45.5	44.7	47.6	44.9
Pmin + RTD Schedule of Preferential and Non-Scheduled Generation	53.7	50.7	48.1	47.8	46.8	44.0	46.9	44.9	47.6	48.9	49.4	53.0	48.3

C. Reserve Margin Index (RMI)[20]

Calculated based on system effective supply[21] vis-à-vis demand plus reserve schedule, the resulting reserve margin index for 2016 showed that wide supply margin generally prevailed throughout the year, though tight supply and demand balance was noted during the second and third quarters. The reserve margin was mostly tight particularly in June, demonstrated by the resulting RMI of less than 10 percent occurring at a high of 60.3 percent. Tight supply and demand balance likewise manifested in April, May, July and August at 41.2 percent, 41 percent, 34.6 percent and 37.9 percent of the time during these months. The occurrence of RMIs of less than 10 percent was predominantly observed during peak hours, as shown in Table 21.

Notwithstanding, the resulting effective supply margin exceeded 10 percent of the hourly demand in majority of the trading intervals at an average of 72.1 percent, and was observed to have followed an increasing trend from September until yearend. The highest frequency of trading intervals with RMIs of more than 10 percent was recorded in December at 95.1 percent.

RMI levels this year generally fared better, indicated by the slight increase in the occurrence of RMIs of more than 10 percent from an average of 71.2 percent in 2015 to 72.1 percent this year. Consequently, RMIs of less than 10 percent decreased from last year's 28.8 percent to 27.9 percent. Nonetheless, it is noted that the billing months of April to June and August to September this year generally exhibited tighter demand and supply balance, when compared with the same billing months in the previous year.

[20] The reserve margin index (RMI) 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. For this Annual Report, the screening threshold is set at 10 percent.

[21] The system effective supply is equal to the offered capacity of all scheduled generator resources, nominated loading level of non-scheduled generating units and projected output of preferential dispatch generating units adjusted for any security limit and ramp rates. Scheduled output of plants on testing and commissioning, through the imposition of security limit by SO, are accounted for in the effected supply. Likewise included is the scheduled output of Malaya plant when it is called to run as Must Run Unit (MRU).

The RMI Duration Curve below shows better supply and demand balance this year, with RMIs of less than 10 percent occurring more frequently in 2015 than in 2016.

Figure 16. Reserve Margin Index (RMI) based on Effective Supply – System

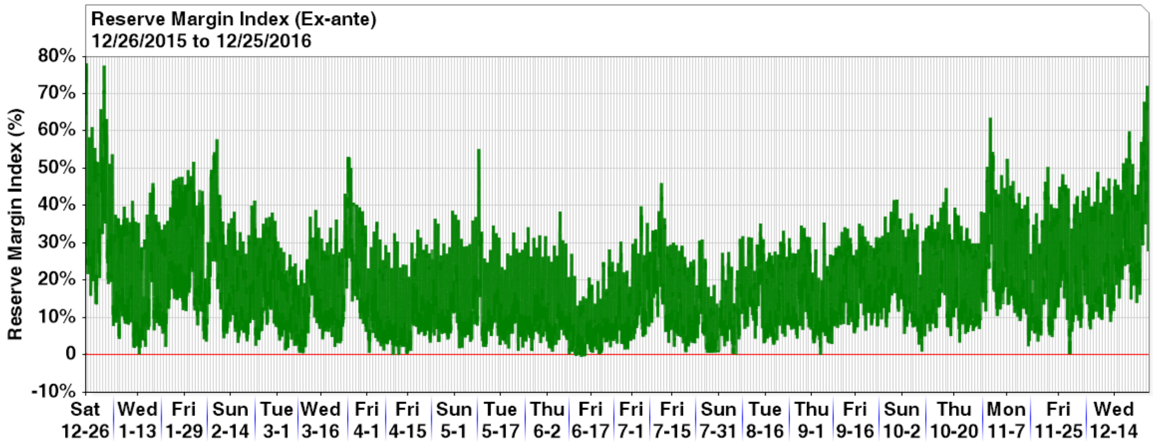

Table 20. RMI Distribution based on Effective Supply – System, 2016

	RMI Distribution by Billing Month (%) - 2016, System												
	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Avg
Less or equal than 10%	15.7	18.3	31.7	41.2	41.0	60.3	34.6	37.9	20.6	15.8	12.9	4.9	27.9
More than 10%	84.3	81.7	68.3	58.8	59.0	39.7	65.4	62.1	79.4	84.2	87.1	95.1	72.1

Table 21. RMI Distribution based on Effective Supply by Hour Type – System, 2016

RMI Distribution	No. of Trading Intervals		Percent of Time	
	Peak	Off-Peak	Peak	Off-Peak
Less or equal to 10%	2,018	421	52.7	8.6
More than 10%	1,808	4,490	47.3	91.4

Figure 17. RMI Duration Curve – Year-on-Year Comparison

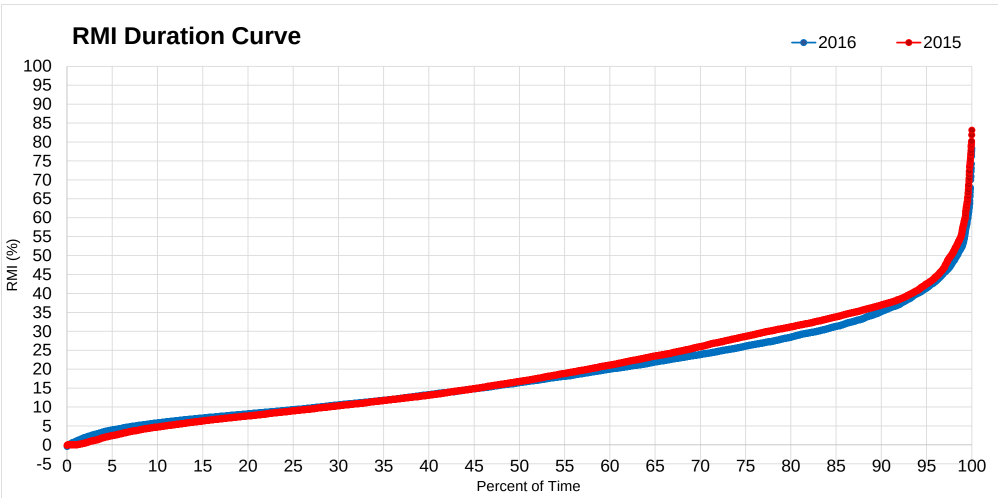

Table 22. RMI Distribution based on Effective Supply – System, 2015

	RMI Distribution by Billing Month (%) - 2015, System												
	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Avg
Less or equal than 10%	15.6	36.4	31.0	21.0	37.8	56.4	34.5	24.5	11.0	22.8	35.2	19.6	28.8
More than 10%	84.4	63.6	69.0	79.0	62.2	43.6	65.5	75.5	89.0	77.2	64.8	80.4	71.2

V. OUTAGES

A. Outage Capacity by Plant Type

Power plant outages continued to influence the level of available supply in the market, resulting in tight supply conditions at certain periods of the year. Nevertheless, outage capacity averaged at 1,956 MW in 2016, recording a modest 3.1 percent decline from last year's 2,019 MW.

Outage capacity was relatively high during the first quarter when demand levels were at their lowest. Coal plants constituted the majority of the plants on outage during this period, with the planned outages of Luzon coal plants Mariveles CFTPP 1 and 2 (01 February to 01 March, and 05 February to 09 March), QPPL CFTPP (15 February to 05 March) and Masinloc CFTPP 2 (01-10 March), as well as the forced outages of SLPGC CFTPP 1 and 2, Masinloc CFTPP 1, Mariveles CFTPP 1 and 2 and SLTEC CFTPP 2, several of which remained on outage for over a month, while Calaca CFTPP 2 was on forced outage for the duration of the first quarter. Similarly in the Visayas, high outage capacity among coal plants was observed with the planned outage of CEDC CFTPP 2 from 25 January to 19 February as well as the forced outages of CEDC CFTPP 3 from 24 February to 02 March, and Units 1 and 2 of PEDC CFTPP, from 25 January to 07 February, and 08 February to 14 March, respectively. In addition, Visayas geothermal plant Malitbog GPP 3 underwent planned outage from 20 January to 28 February. Consequently, outage capacity averaged at a high of 2,265 MW in January, 2,230 MW in February and 2,214 MW in March, but decreased in April and May, averaging at 1,749 MW and 1,143 MW, with the resumption of operations of several plants that were on outage in the first quarter. Nevertheless, high outage capacity was noted among hydro plants during the period with the planned outages of Ambuklao HEP 1-3, Magat HEP 1-4 in April and Pantabangan 1 and 2 in May, while maintenance outages were recorded for San Roque HEP 1 and 3, and Kalayaan PSPP 1 during the period. Further, Kalayaan PSPP 3 underwent forced outage on 14-17 April while its unit 4 was on forced outage from 14 April until 10 May.

Outage capacity rose to an average of 1,898 MW in June while demand was still at its peak. Said increase in outage capacity was mainly driven by the increase in the forced outage capacity involving coal plants. Spike in the level of outage capacity was noted particularly from 11-15 June with the series of forced outages of major coal plants Sual CFTPP 1, Calaca CFTPP 1, QPPL CFTPP, SLTEC CFTPP 1, KSPC CFTPP 1 and 2, CEDC 3, and the maintenance outages of Mariveles CFTPP 2 from 10-12 June and SLTEC CFTPP 2 from 09-12 June. These were on top of the planned outages of large coal plant Pagbilao CFTPP 2 from 17 May-28 July, natural gas plant San Lorenzo NGPP 1 and 2 from 17-20 June and Visayas geothermal plant Malitbog GPP 1 from 23 May to 16 June. Outage capacity declined to 1,715 MW in July following the decrease in the outage capacity among coal plants. On the contrary, the outage capacity natural gas plants rose noticeably during the month. Avion NGPP was on short duration outages from 25 June to 21 July, Units 1 to 4 of Sta. Rita NGPP were on a series of planned outages throughout the July billing month, while Ilijan NGPP Block B was on forced outage from 19-23 July. Meanwhile, Kalayaan PSPP 2 was on planned outage from 04 July which lasted until 19 September.

Outage capacity demonstrated a significant increase of about 50 percent in August, averaging at 2,573 MW, the highest monthly average outage capacity during the year. This was substantially influenced by the consecutive outages of major power plants particularly during the period 26 July to 01 August, which saw increasing events of unscheduled outages of several major power plants in the Luzon region. Consequently, the National Grid

Corporation of the Philippines-System Operator (NGCP-SO) placed the region under yellow alert and red alert status[22], affecting a total of 40 and 13 trading intervals, respectively.

As illustrated in Figure 18 below, natural gas plants recorded the highest month-on-month increase of 339.4 percent, from last month's average of 171 MW to a high of 752 MW during the August billing month, driven by the planned outages of Sta. Rita NGPP 2 (22 July to 26 August) and Ilijan NGPP Block B (04-30 August), which went on for the duration of the August billing month. Also during this period, several plants went on forced outages almost simultaneously, namely: coal plants Mariveles CFTPP 1 (29 July to 02 August), Sual CFTPP 2 (27-31 August), Calaca CFTPP 2 (26 July to 02 August, 05-07 August), CEDC CFTPP 2 (26 July to 01 August), SLTEC CFTPP 1 and 2 (31 July to 11 August and 19 July to 03 August), and QPPL CFTPP (05-09 August), and the maintenance outages of Malitbog GPP 2 (30 July to 03 August) and Kalayaan PSPP 1 (04-18 August). In addition, geothermal plant Bacman GPP 2 went on planned outage from 29 July to 07 August.

Furthermore, Pagbilao CFTPP 2, which planned outage was scheduled from 17 May to 28 July was able to resume operations on 27 July, but went on forced outage on 29 July to 07 August, due to boiler tube leak. It is also noted that Malaya TPP 1, which was unavailable most of the time since March only resumed full operations on 27 July. After which, unit 2 of Malaya TPP went on forced outage on 29 July to 02 August and on maintenance outage from 15 August to 05 September. It is also important to note the existing planned outages of hydro plant Kalayaan PSPP 2, coal plants SLPGC CFTPP 2 (12 July to 26 August) and KSPC CFTPP 1 (11 August to 05 September). Likewise, geothermal plant Malitbog GPP 1 was on maintenance outage from 20 July lasting until 16 October.

The continuing outages of the plants above-mentioned contributed to the high outage level in September, which averaged at 2,106 MW. On top of these, the following outages were noted during the month: forced outages of Calaca CFTPP Unit 1 from 29 August to 16 September, and Calaca CFTPP Unit 2 from 29 August to 06 September; as well as the short-duration forced outages of Masinloc CFTPP 2, Sual CFTPP 1 and 2, Mariveles CFTPP 2, SLTEC CFTPP 2 and SLPGC CFTPP 2. Large generating coal plant Sual CFTPP 2 also began its annual planned outage on 26 August lasting until 15 September. Visayas coal plants likewise contributed in the increase in outage capacity this month with the planned outages of KSPC CFTPP 1 from 11 August to 05 September and of TPC Sangi CFTPP 2 from 15-30 September. Meanwhile, Sta. Rita NGPP 2, went on forced outage from 26 August to 25 September. Ilijan NGPP Block A2 also went on planned outage from 18-29 September.

A steady decline in the level of outage capacity was recorded during the last quarter of the year, with monthly outage capacity averaging at 1,712 MW in October, then posting an increase at 2,041 MW in November, which reverted to an average of 1,799 MW in December. Despite the said decline, the maximum outage during the year was recorded at 4,244 MW on 15 November from 2100H to 2300H driven by the forced outages of large plants Mariveles CFTPP 2, QPPL CFTPP, Sta. Rita NGPP 1 and 4, San Lorenzo NGPP 1 and 2, all of which went on outage on account of the major system trouble during the day. These were on top of the series of forced outage of Calaca CFTPP 2 from 13-18 November, as well as the existing outages of Sual CFTPP 1 (planned outage from 30 September to 13 December), SLPGC CFTPP 2 (forced outage from 12 November to 09 December), and Sta. Rita NGPP 3 (maintenance outage from 22 October to 25 November).

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[22] Under the Philippine Grid Code (PGC), a yellow alert notice is warranted when the Contingency Reserve is less than the capacity of the largest Synchronized Generating Unit or power import from a single interconnection, whichever is higher. Meanwhile, a red alert is issued when Contingency Reserve is zero or a generation deficiency exists or if there is Critical Loading or Imminent Overloading of transmission lines or Equipment.

In addition to these, high outage capacity of coal plants during the last quarter was also influenced by following: Sual CFTPP 2, which went on short-duration forced outages from 07 to 11 and 21 October, simultaneous forced outages of Mariveles CFTPP 1 and 2, Masinloc CFTPP 1 and 2, SLPGC CFTPP 1 and 2, Anda CFTPP 1 and SLTEC 1 from 07-09 October; series of short-duration forced outages of Calaca CFTPP 1 and 2, Mariveles CFTPP 1 and 2 Masinloc CFTPP 1 and 2, SLPGC CFTPP 1 and 2 during the December billing month. On the other hand, Visayas coal plants CEDC CFTPP 1 and 3 and KSPC CFTPP 1 were noted to be on a series of forced outages in November and December, while CEDC CFTPP 3, TPC Sangi CFTPP 2 and KSPC CFTPP 2 all underwent planned outages from 01 to 08 October, and from 15 to 30 October and from 17 October until 12 November, respectively, in part driving high outage capacity in the region in the November billing month.

Further in Luzon, the maintenance outage of Sta. Rita NGPP 3 from 22 October until 25 November, which was extended as forced outage until 30 November was also noted as well as the forced outages of San Gabriel NGPP, Sta. Rita NGPP 1, 2 and 4 and San Lorenzo NGPP 1 and 2. The November billing month also saw the month-long maintenance outage of Makban GPP 3 and the short duration maintenance outages of Bacman GPP 2 and 3. Kalayaan PSPP 3, which was on forced outage starting 31 August, remained on forced outage for the rest of November (until 30 November), while Kalayaan PSPP 1 and 4 both registered maintenance outages during the month. Meanwhile, the outages of geothermal plants in December, particularly Bacman GPP and Tiwi GPP, were mostly related to the onslaught of Typhoon Nina on Christmas Day which mainly hit the Bicol Region.

Figure 18. Capacity on Outage by Plant Type – System

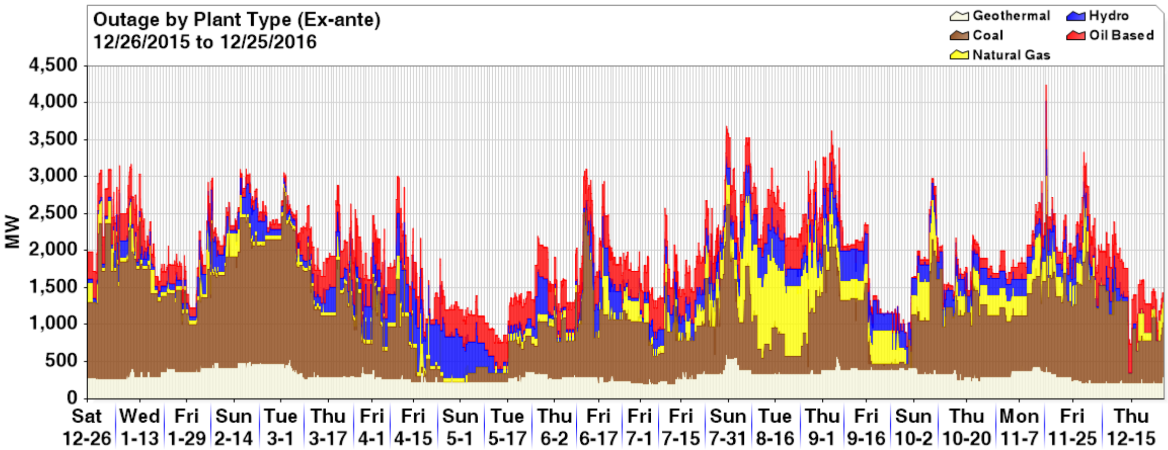


Table 23. Capacity on Outage by Plant Type – System

Plant Type	Outage Capacity by Plant Type (Average MW) - 2016, System												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
Coal	1,424	1,347	1,379	583	209	884	708	753	786	853	1,022	1,010	913
Natural Gas	120	110	58	79	44	96	171	752	393	226	272	111	204
Geothermal	306	431	349	275	255	282	256	373	391	335	336	220	318
Hydro	99	229	147	444	273	238	186	322	344	235	251	86	239
Oil-Based	316	113	281	368	362	398	394	373	191	63	160	372	282
Total	2,265	2,230	2,214	1,749	1,143	1,898	1,715	2,573	2,106	1,712	2,041	1,799	1,956

Table 24. Year-on-Year Average Outage Capacity Comparison – System

	Year-on-Year Average Outage Capacity Comparison by Billing Month												
	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Avg.
2016 (MW)	2,265	2,230	2,214	1,749	1,143	1,898	1,715	2,573	2,106	1,712	2,041	1,799	1,956
2015 (MW)	2,722	2,976	2,383	1,632	1,327	1,969	2,079	1,779	1,141	1,771	2,238	2,220	2,019
Y-Y (%) Change	(16.8)	(25.1)	(7.1)	7.2	(13.9)	(3.6)	(17.5)	44.7	84.6	(3.3)	(8.8)	(18.9)	(3.1)

Figure 19. Capacity on Outage by Plant Type – Luzon

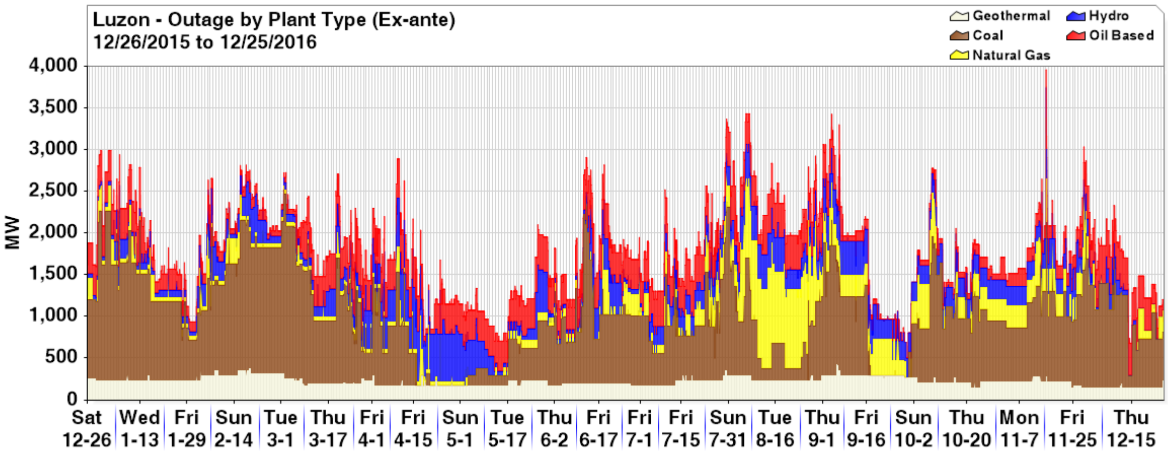


Table 25. Capacity on Outage by Plant Type – Luzon

Plant Type	Outage Capacity by Plant Type (Average MW) - 2016, Luzon												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
Coal	1,289	1,194	1,265	499	200	850	705	664	712	786	850	943	829
Natural Gas	120	110	58	79	44	96	171	752	393	226	272	111	204
Geothermal	245	299	231	197	193	201	209	261	292	228	224	162	229
Hydro	99	229	147	444	273	238	186	322	344	235	251	86	239
Oil-Based	313	113	279	366	359	392	392	372	189	58	156	366	279
Total	**2,065**	**1,945**	**1,980**	**1,586**	**1,071**	**1,776**	**1,664**	**2,371**	**1,931**	**1,532**	**1,754**	**1,668**	**1,781**

Table 26. Year-on-Year Average Outage Capacity Comparison – Luzon

	Year-on-Year Average Outage Capacity Comparison by Billing Month, Luzon												
	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Avg.
2016 (MW)	2,065	1,945	1,980	1,586	1,071	1,776	1,664	2,371	1,931	1,532	1,754	1,668	1,781
2015 (MW)	2,466	2,709	2,159	1,503	1,184	1,783	1,995	1,639	1,041	1,695	2,075	2,124	1,863
Y-Y (%) Change	(16.2)	(28.2)	(8.3)	5.5	(9.6)	(0.4)	(16.6)	44.7	85.5	(9.6)	(15.5)	(21.4)	(4.4)

Figure 20. Capacity on Outage by Plant Type – Visayas

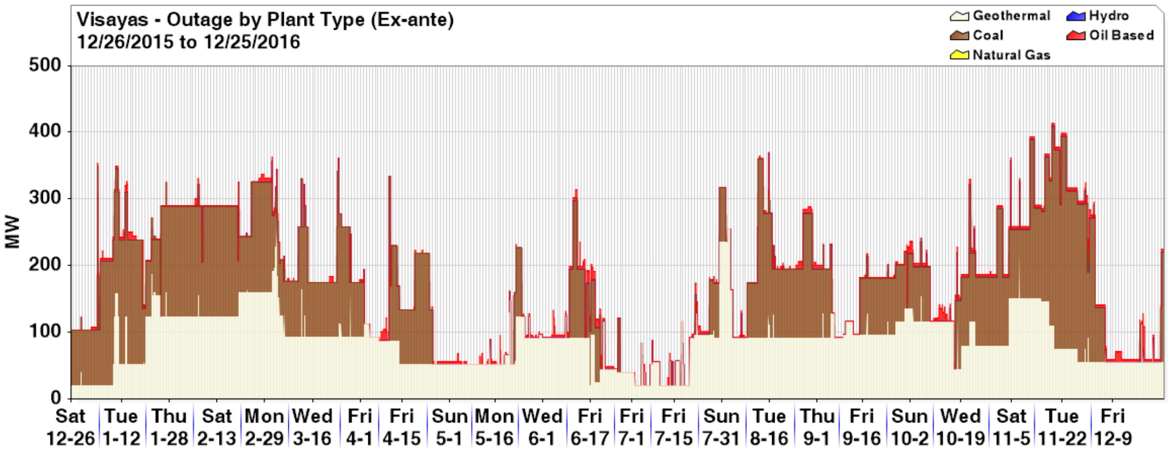


Table 27. Capacity on Outage by Plant Type – Visayas

Plant Type	Outage Capacity by Plant Type (Average MW) - 2016, Visayas												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
Coal	135	153	114	84	9	34	3	89	74	67	172	67	84
Geothermal	61	132	118	78	61	81	47	113	99	107	112	58	89
Oil-Based	3	0	2	1	2	6	2	1	2	5	4	7	3
Total	**199**	**285**	**234**	**163**	**72**	**121**	**52**	**203**	**175**	**180**	**287**	**131**	**176**

Table 28. Year-on-Year Average Outage Capacity Comparison – Visayas

	Year-on-Year Average Outage Capacity Comparison by Billing Month, Visayas												
	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Avg.
2016 (MW)	199	285	234	163	72	121	52	203	175	180	287	131	176
2015 (MW)	256	267	223	129	143	186	84	140	100	76	163	96	155
Y-Y (%) Change	(22.1)	6.7	4.8	26.3	(49.6)	(35.0)	(38.0)	44.7	74.4	136.6	76.3	36.1	13.0

B. Outage Capacity by Outage Type[23]

About 55.8 percent of the total outage capacity was on account of unplanned outages, which averaged at 1,092 MW during the year. This comprised of forced and maintenance outages. On the other hand, 35.8 percent was attributable to planned outages, averaging at 700 MW, while deactivated shutdown averaged at 164 MW, accounting for the remaining 8.4 percent.

The highest level of monthly outage capacity was posted in August, attributable to the high unplanned outage during the month, which averaged at 1,233 MW while planned outage capacity was likewise at its highest, posted at an average of 1,187 MW.

Figure 21. Capacity on Outage by Outage Type

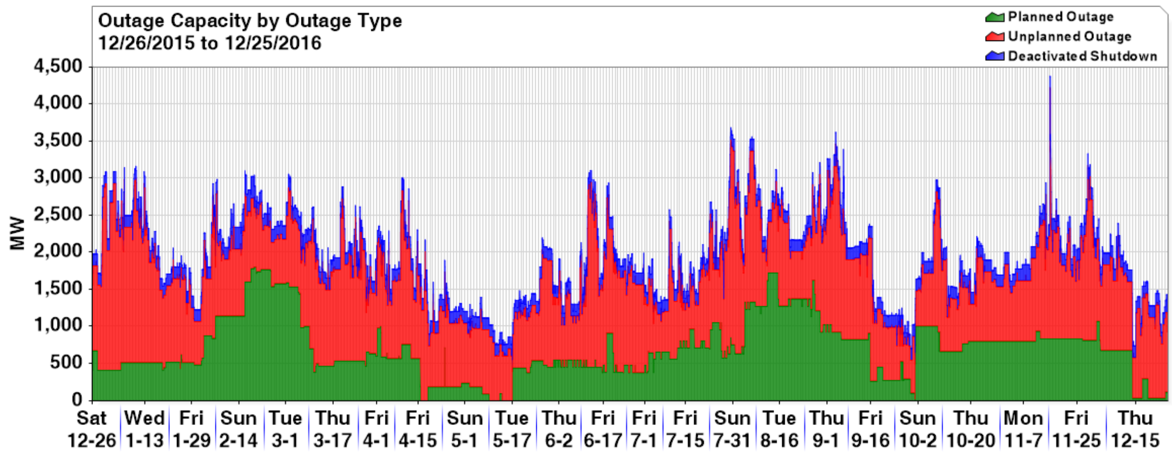


Table 29. Capacity on Outage by Outage Type – System

Plant Type	Outage Capacity by OutageType (Average MW) - 2016, System												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
Planned Outage	497	1,150	889	471	221	512	673	1,187	748	731	825	480	700
Unplanned Outage	1,600	888	1,163	1,112	762	1,233	886	1,233	1,197	820	1,052	1,148	1,092
Deactivated Shutdown	158	194	166	161	158	158	159	158	165	159	164	168	164

C. Outage Frequency

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 251 incidents, followed by natural gas plants with 208 outage incidents and coal plants, with 207. Geothermal plants came next, recording a total of 187 outage incidents across the year while hydro plants posted a total of 137 outage incidents. On the other hand, outage frequency based on outage category showed that forced outages recorded the highest number of outage incidents at 602,

[23] 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".

distantly followed by planned outages at 174 and maintenance outages at 161. Deactivated shutdown recorded the lowest, with a total of 53 outage incidents during the year. 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 990 across the 2016 billing year.

The June billing month posted the highest number of outage incidents in 2016, driven by the high number of forced and planned outages during the period. Natural gas and oil-based plants contributed the bulk in the count of outage incidents in June, registering the highest occurrences at 48 and 38 incidents, respectively. The frequency of outage incidents was likewise high in August, posting a total of 95 incidents during the month. Planned and forced outage incidents during the period totalled at 33 and 52, respectively, which were also mostly due to the outages involving natural gas and oil-based plants.

Table 30. Monthly Frequency of Outage Incidents by Plant Type, 2016

Plant Type	Monthly Frequency of Outages by Plant Type, 2016-System												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
COAL	16	23	18	24	5	19	16	17	16	19	18	16	207
GEO	19	13	18	11	12	14	22	19	15	15	12	17	187
HYD	13	13	8	19	10	11	6	4	5	11	5	32	137
NATG	9	6	6	10	18	48	27	30	21	12	11	10	208
OIL	21	9	21	27	27	38	21	25	11	24	12	15	251
Total	**78**	**64**	**71**	**91**	**72**	**130**	**92**	**95**	**68**	**81**	**58**	**90**	**990**

Table 31. Monthly Frequency of Outage Incidents by Outage Category, 2016

Outage Category	Monthly Frequency of Outages by Outage Category, 2016-System												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Planned Outage	9	10	7	13	9	42	26	33	12	9	1	3	174
Forced Outage	47	35	50	62	59	72	50	52	40	57	37	41	602
Maintenance Outage	22	16	12	12	4	16	14	10	9	12	18	16	161
Deactivated Shutdown	0	3	2	4	0	0	2	0	7	3	2	30	53
Total	**78**	**64**	**71**	**91**	**72**	**130**	**92**	**95**	**68**	**81**	**58**	**90**	**990**

D. Outage Factor[24]

Geothermal plants posted the highest total outage factor this year among all plant types at 18 percent, mainly attributable to the high outage factor of the geothermal plants from Luzon due to deactivated shutdown. Coal plants recorded the next highest outage factor at 15.1 percent, followed by oil-based plants at 12.3 percent, hydro plants at 9.5 percent and natural gas plants at 6.4 percent.

Forced outage remain high during the year, accounting for 4.6 percent of the total outage factor. Coal, hydro and oil-based plants recorded the highest forced outage factors from among all the resource types at 6.2 percent, 4.4 percent and 8.3 percent respectively. Meanwhile, 4.1 percent of the total outage factor was attributed to planned outage. Coal plants ranked first in terms of planned outage factor at 8.1 percent, followed by natural gas plants at 3.1 percent. Lastly, outage factors for maintenance outage and deactivated shutdown were recorded at 1.8 percent and 1 percent respectively.

Results of regional outage factors showed higher outage factor in Luzon at 12.5 percent than in the Visayas which total outage factor was posted at 6.3 percent.

[24] 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.

Figure 22. Outage Factor – System

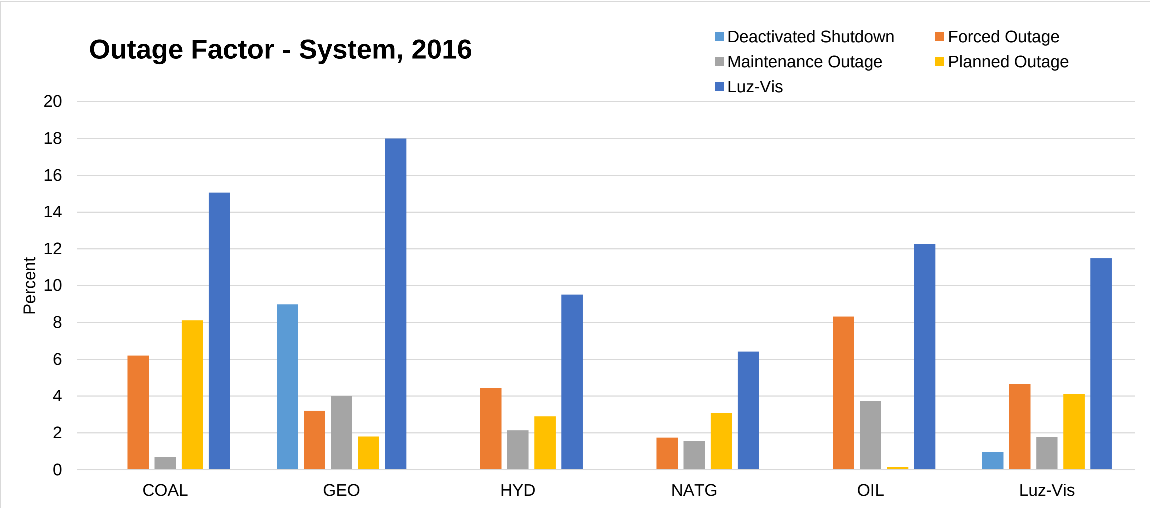


Figure 23. Outage Factor – Luzon

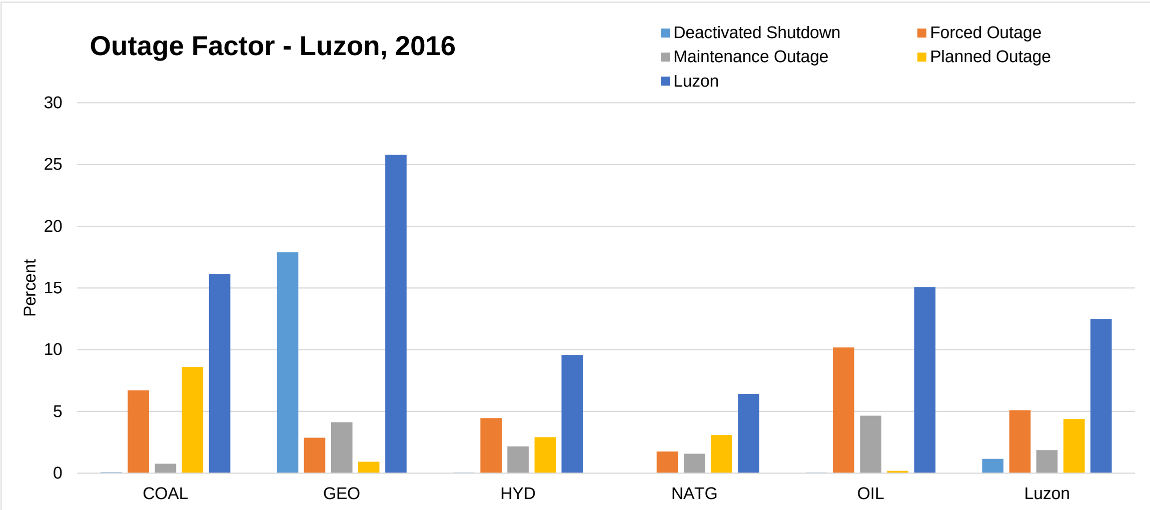


Figure 24. Outage Factor – Visayas

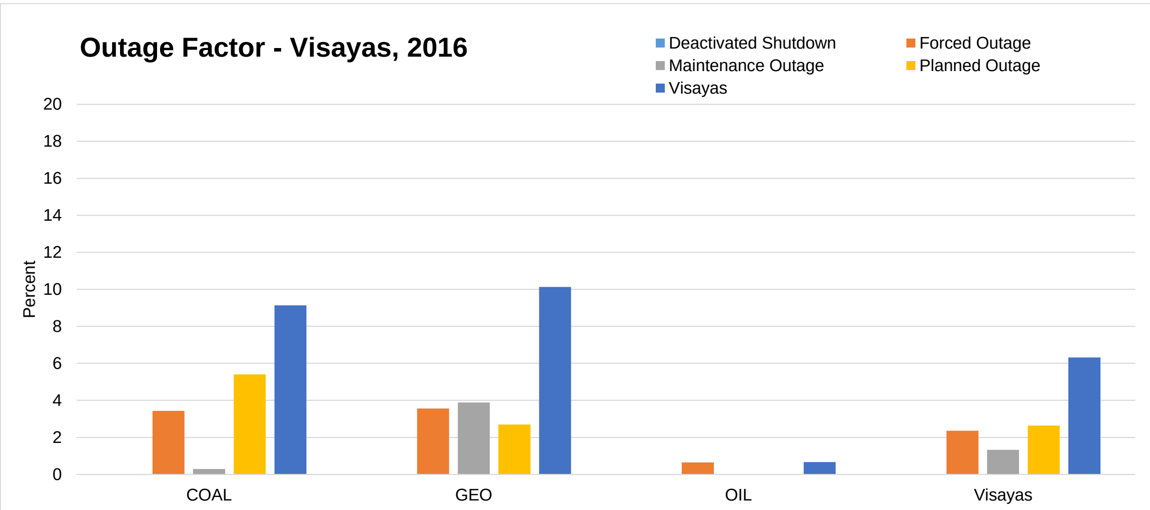


Table 32. Outage Factor Summary – 2016

Plant Type	Summary of Outage Factor, 2016													
	System					Luzon					Visayas			
	Planned Outage	Forced Outage	Maintenance	D/S	Total	Planned Outage	Forced Outage	Maintenance	D/S	Total	Planned Outage	Forced Outage	Maintenance	Total
Coal	8.1	6.2	0.7	0.1	15.1	8.6	6.7	0.8	0.1	16.1	5.4	3.4	0.3	9.1
Natural Gas	3.1	1.7	1.6	0.0	6.4	3.1	1.7	1.6	0.0	6.4				
Geo	1.8	3.2	4.0	9.0	18.0	0.9	2.9	4.1	17.9	25.8	2.7	3.6	3.9	10.1
Hydro	2.9	4.4	2.1	0.0	9.5	2.9	4.5	2.2	0.0	9.6				
Oil-Based	0.2	8.3	3.7	0.0	12.3	0.2	10.2	4.6	0.0	15.1	-	0.6	0.0	0.7
Total	**4.1**	**4.6**	**1.8**	**1.0**	**11.5**	**4.4**	**5.1**	**1.9**	**1.2**	**12.5**	**2.6**	**2.4**	**1.3**	**6.3**

Table 33. Monthly Outage Factor Summary – 2016

Plant Type	Outage Type	Outage Factor (%) by Billing Month - System-2016												
		Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Avg
COAL	Planned Outage	7.8	16.4	13.2	4.6	1.9	6.3	7.5	3.4	7.8	9.9	12.4	6.6	8.1
	Forced Outage	15.5	4.3	8.4	5.1	1.6	7.4	3.1	8.9	4.9	4.1	3.7	7.7	6.2
	Maintenance Outage	0.7	1.5	1.7	0.0	0.0	0.9	1.1	0.2	0.1	0.0	0.3	1.7	0.7
	Deactivated Shutdown	0.0	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
COAL Total Outage Factor		24.0	22.8	23.2	9.7	3.5	14.6	11.7	12.5	12.8	13.9	16.4	16.1	15.1
NATG	Planned Outage	0.5	0.0	-	0.1	0.2	2.3	2.7	22.6	3.8	3.0	-	0.8	3.1
	Forced Outage	1.6	2.2	1.8	1.9	1.2	0.6	1.0	-	8.0	1.1	0.2	1.4	1.7
	Maintenance Outage	2.1	1.7	0.1	0.5	0.0	0.2	1.5	0.4	0.2	2.8	8.1	1.1	1.6
	Deactivated Shutdown	0.0	-	0.0	0.0	0.0	0.0	-	0.0	0.1	0.0	0.0	0.0	0.0
NAT GAS Total Outage Factor		4.2	3.9	1.9	2.4	1.4	3.1	5.3	23.0	12.0	6.9	8.3	3.3	6.4
GEO	Planned Outage	0.8	6.9	2.8	0.2	0.4	2.9	0.0	1.0	-	1.5	3.1	2.0	1.8
	Forced Outage	1.5	3.0	5.7	4.4	2.5	1.8	3.3	4.9	5.1	2.5	2.5	1.3	3.2
	Maintenance Outage	6.1	5.6	2.0	1.9	2.7	2.3	2.3	6.3	7.9	5.9	4.5	0.1	4.0
	Deactivated Shutdown	8.9	8.9	9.4	9.1	8.9	8.9	8.9	8.9	9.2	9.0	8.9	9.0	9.0
GEO Total Outage Factor		17.3	24.4	19.9	15.6	14.5	15.9	14.5	21.1	22.1	18.9	19.0	12.5	18.0
HYD	Planned Outage	0.3	2.2	2.3	7.6	3.7	0.2	5.3	7.2	5.8	-	-	-	2.9
	Forced Outage	2.0	2.0	2.3	6.2	5.9	3.5	2.0	2.1	7.9	9.3	8.3	1.5	4.4
	Maintenance Outage	1.4	4.8	1.2	3.9	1.1	5.8	0.1	3.6	0.2	0.1	1.7	1.5	2.1
	Deactivated Shutdown	-	-	-	-	-	-	-	-	-	0.0	-	0.3	0.0
HYDRO Total Outage Factor		3.8	9.0	5.9	17.7	10.6	9.5	7.5	12.9	13.9	9.4	10.1	3.4	9.5
OIL	Planned Outage	0.0	0.0	0.0	0.0	0.0	-	0.0	1.8	-	-	-	-	0.2
	Forced Outage	5.0	4.8	11.5	14.9	15.9	16.5	16.6	9.2	2.7	0.5	0.5	2.3	8.3
	Maintenance Outage	8.0	0.0	0.4	1.2	-	1.0	0.6	5.3	5.7	2.4	6.2	14.1	3.7
	Deactivated Shutdown	-	-	-	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.3	0.0	0.0
OIL Total Outage Factor		12.9	4.8	11.9	16.1	15.9	17.5	17.3	16.4	8.4	2.8	7.0	16.4	12.3

VI. CAPACITY GAP[25]

Supply availability in the market is likewise influenced by the continued submission by generator-trading participants of capacity offers less than their respective maximum available capacity, as indicated by the persistently high level of capacity gap throughout the billing year. Following relevant provisions in the WESM Rules, these shall be subject to further investigation for possible non-compliance with the must-offer rule.

Similar with the previous year, majority of the capacity gap in the market is attributed to hydro plants, which capacity gap averaged at 915 MW, and accounted for about 35.6 percent of the total capacity gap during the year. Higher level of capacity gap among hydro plants was observed during the second and third quarters – particularly from April to August, as shown in Figure 20 below. During this period, the monthly average capacity gap among hydro plants ranged from 1,004 MW to 1,331 MW. It is noted that the capacity offers submitted by hydro plants during this period is lower when compared with the rest of the billing months.

[25] Capacity gap is calculated as 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.

Next to hydro plants, coal plants contributed 25.8 percent of the total capacity gap, averaging at 663 MW. Coal plants likewise recorded higher levels of capacity gap during the summer - from April to June, when compared with the rest of the billing months. Relative to this, it is noted that the maximum level of capacity gap during the year was posted at 4,432 MW on 31 July at 1700H.

The remaining 14.2 percent, 13.7 percent and 11.2 percent of the total capacity gap were attributed to natural gas plants, oil-based plants and geothermal plants, which closely averaged at 365 MW, 352 MW and 287 MW, respectively.

Year-on-year comparison of capacity gap levels showed a notable 9.7 percent rise in the level of capacity gap during the year, averaging at 2,577 MW from 2,344 MW in 2015. Said increase can be attributed to the significant rise by about 205 percent in the level of capacity gap among natural gas plants from an average of 119 MW in 2015 to 365 MW this year. In part, this is due to the non-submission of offers by natural gas plants that are still under testing and commissioning. These will not be subject to further investigation considering that generators under testing and commissioning are not yet allowed to submit capacity offers in the market.

Figure 25. Capacity Gap – System

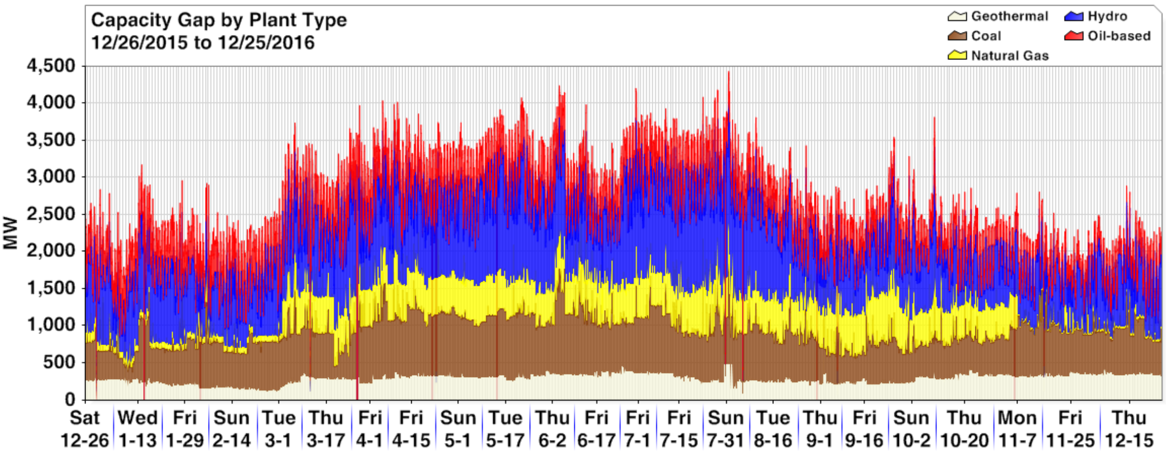


Table 34. Capacity Gap – System

Plant Type	Capacity Gap by Plant Type (Average MW) - 2016, System												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
Coal	485	603	629	859	836	810	743	701	528	507	642	610	663
Natural Gas	90	84	425	507	501	494	538	485	565	475	190	36	365
Geothermal	252	171	254	301	307	351	331	268	237	299	331	349	287
Hydro	850	705	966	1,040	1,190	1,004	1,331	1,167	730	705	612	694	915
Oil-Based	430	410	380	419	406	370	386	368	301	298	235	216	352
Total	**2,087**	**1,971**	**2,651**	**3,073**	**3,236**	**3,030**	**3,330**	**2,959**	**2,351**	**2,284**	**2,002**	**1,904**	**2,571**

Table 35. Year-on-Year Average Capacity Gap Comparison

	Year-on-Year Average Capacity Gap Comparison by Billing Month												
	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Avg.
2016 (MW)	2,087	1,971	2,651	3,073	3,236	3,030	3,330	2,959	2,351	2,284	2,002	1,904	2,571
2015 (MW)	2,149	2,259	2,529	2,766	2,860	2,420	2,282	2,348	2,250	2,038	2,069	2,176	2,344
Y-Y (%) Change	(2.9)	(12.8)	4.8	11.1	13.2	25.2	45.9	26.0	4.5	12.1	(3.2)	(12.5)	9.7

VII. MARKET PRICE OUTCOME[26]

A. Market Prices

Market prices averaged at PhP2,948/MWh, the lowest annual average price in the WESM since the integration of the Visayas market in 2011. A decrease of about 23 percent was observed from last year's average price of PhP3,829/MWh, and a further decrease of about 39.9 percent from the average market price in year 2014 posted at PhP4,904/MWh. It is significant to note that since the previous year 2015, there had been no imposition of the secondary price cap[27]. Notwithstanding, and despite the wider supply margins which were generally experienced in the market, price spikes were still observed in trading intervals which manifested tight supply conditions resulting from the unavailability of several plants, though these occurred less frequently when compared with the two previous billing years.

It was observed that market prices were at their lowest at the start of the year, with the January prices averaging at PhP2,038/MWh, the lowest monthly average price in two years. It is worth noting that hourly market prices fell below the monthly average level majority of the time during the month, but increased at an average of PhP2,306/MWh in February. The March and April billing months posted relatively higher prices averaging at PhP3,297/MWh and PhP3,411/MWh, respectively, as demand started to pick-up. Spikes in market prices were noticeably observed in April, driven by seasonal demand increase during the summer. Notwithstanding the high demand requirement in May, market prices subsequently dropped to an average of PhP2,727/MWh, following the decline in outage capacity that resulted to better supply conditions during the month.

Market prices were at their highest in June, averaging at PhP4,693/MWh. The June billing month was marked with tight supply conditions, while electricity demand remained relatively high. Consequently, the narrow supply margin which prevailed during the month was accompanied by the increase in market prices which were highest during the year.

Meanwhile, the August billing month recorded the highest outage capacity this year, resulting in higher market prices during the month, and essentially demonstrating that market prices are influenced by the level of available supply in the market. Consequently, due to tight supply conditions resulting from the consecutive outages of major power plants, particularly during the first week of the August billing month, this period showed occurrences of sustained high market prices driving the monthly average price in August to increase by about 42.7 percent to an average of PhP4,047/MWh, from PhP2,837/MWh in July.

Nevertheless, as supply availability increased in the months that followed, market prices likewise eased and went on a downward trend until yearend as monthly average prices ranged from PhP2,765/MWh in September to PhP2,148/MWh in December. This notwithstanding, price spikes above PhP30,000/MWh were still observed during the September and December billing months, as shown in the Figure below.

The maximum price on record was posted at PhP33,467/MWh on 11 June at 2300H. Market prices above PhP30,000/MWh were noted in 14 trading intervals across the year, five (5) of which were posted on 11 June, from 2000H to 2400H. The high prices during this period is

[26] 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.

[27] 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.

consistent with the tight supply which was prevalent during the billing month, particularly on 11-15 June, with the unavailability of major coal plants Sual CFTPP 1, Calaca CFTPP 1, QPPL CFTPP, SLPGC 1, SLTEC CFTPP 1 and 2, Mariveles CFTPP 2, and Pagbilao CFTPP 2. On 11 June in particular, the forced outages of Sual CFTPP 1 and QPPL CFTPP which begun that day at 1158H and 1544H, respectively, pushed supply levels further down until the end of the trading day, resulting in the dispatch of higher-priced plants.

Market prices above PhP30,000/MWh were likewise observed in April – on 09 April at 1900H and 2100H as a result of tight supply due to the outages of major plants namely Sual CFTPP 2, San Lorenzo NGPP 2, and Magat HEP 3 and 4; and on 11 April at 1700H-1900H, when supply margin dropped to a mere 12 to 16 MW-level with the forced outage of the 647-MW Sual CFTPP 2, on top of the existing outages of major coal plants.

Market prices likewise went above the PhP30,000/MWh mark on 03 September at 2300H, despite the lower prices recorded during the month following the simultaneous forced outages of major plants Masinloc CFTPP 2, Ilijan NGPP Block B1 and GNPower CFTPP 2 in addition to the existing outages of Calaca CFTPP 1 and 2, Sual CFTPP 2, Sta, Rita NGPP 2 and Kalayaan PSPP 3. Lastly, during the December billing month, particularly on 28 November at 1500H and 1800H, market prices again rose above PhP30,000/MWh attributable to the overlapping outages of major natural gas and coal plants.

On the other hand, the minimum price on record was posted at negative PhP-100,654/MWh on 26 December 2015 at 0400H followed by negative PhP-89,664/MWh at 0600H. No other extreme negative price was recorded this year, following the issuance of Resolution No. 3, s.2015[28] which set the offer price floor in the WESM at negative PhP10,000/MWh effective 01 January. Notwithstanding, negative market prices were still noted in another 31 trading intervals across the year, the lowest of which was at negative PhP10,616/MWh, posted on 01 January at 0900H.

Figure 26. Market Price Trend – System

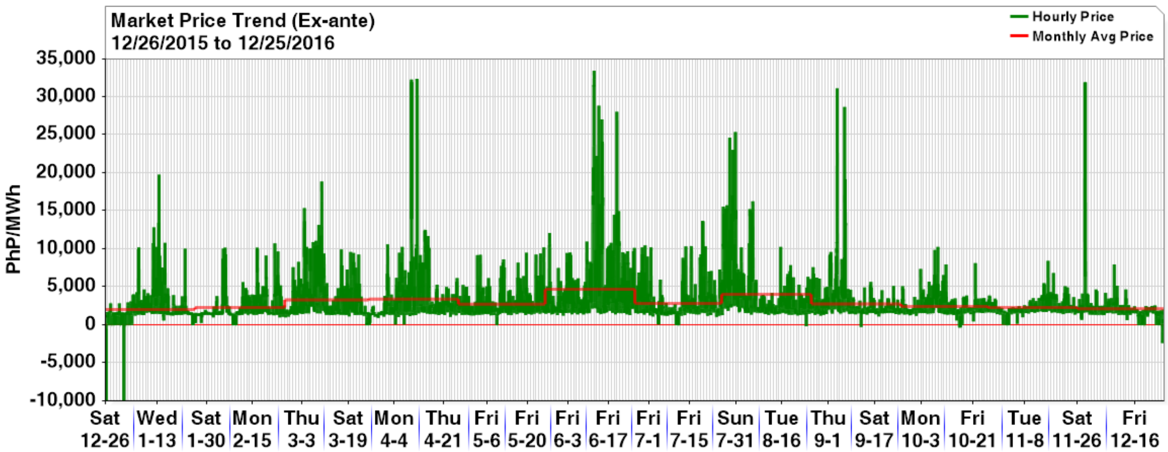


Table 36. Market Price Trend – System

	Market Price Trend (PhP/MWh) by Billing Month - 2016, System												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Max	19,789	10,744	18,896	32,415	10,208	33,467	13,725	25,392	31,146	10,271	8,457	31,945	33,467
Min	(100,654)	-	-	-	-	1,234	(12)	(170)	(275)	(334)	(0)	(2,379)	(100,654)
Avg	2,038	2,306	3,297	3,411	2,737	4,693	2,837	4,047	2,765	2,429	2,294	2,148	2,948

[28] As a price mitigating measure, the WESM Tripartite Committee composed of the DOE, ERC and PEMC issued Resolution No. 3 on 17 December 2015, which adopted the Offer Price Cap at PhP32,000/MWh, as initially set on 27 December 2013. The same Resolution also set the Offer Price Floor in the WESM at negative PhP10,000/MWh effective 01 January 2016.

Table 37. Year-on-Year Average Price Trend Comparison - System

	Year-on-Year Average Price Trend Comparison (PhP/MWh)												
	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Avg
2016	2,038	2,306	3,297	3,411	2,737	4,693	2,837	4,047	2,765	2,429	2,294	2,148	2,948
2015	3,381	5,101	5,105	2,824	4,512	6,402	4,473	3,729	2,168	2,536	3,249	2,486	3,829
(%) Change	(39.7)	(54.8)	(35.4)	20.8	(39.3)	(26.7)	(36.6)	8.5	27.5	(4.2)	(29.4)	(13.6)	(23.0)

Price separations between the Luzon and Visayas regions were noted to have occurred over the course of the billing year due to the regional application of pricing errors as well as the occurrences of constraints in the HVDC. It is also important to note the unavailability of the HVDC in 153 trading intervals from 0900H of 10 October to 16 October at 1700H due to the annual preventive maintenance of Ormoc HVDC Converter Station, which likewise resulted in the price separation between the regions.

During the year, Luzon market prices averaged at PhP2,945/MWh, which was slightly lower by about 0.6 percent from the average price in Visayas at PhP2,962/MWh. Correspondingly, monthly regional price outcomes showed that average market prices in Visayas were generally higher than the market prices in the Luzon region. It is also observed that negative prices occurred more frequently in Visayas than in Luzon. This notwithstanding, Luzon recorded a slightly higher maximum price of PhP33,530/MWh posted on 06 September at 1300H, higher by 0.2 percent from the maximum price recorded in Visayas at PhP33,467/MWh on 11 June at 2300H.

Year-on-year comparison of Luzon prices showed that market prices in the current year was lower by about 22.5 percent from the market prices in 2015 which averaged at PhP3,799/MWh. Similarly, Visayas prices also decreased by about 25.9 percent from last year's market prices which averaged at PhP3,996/MWh.

Figure 27. Market Price Trend – Luzon

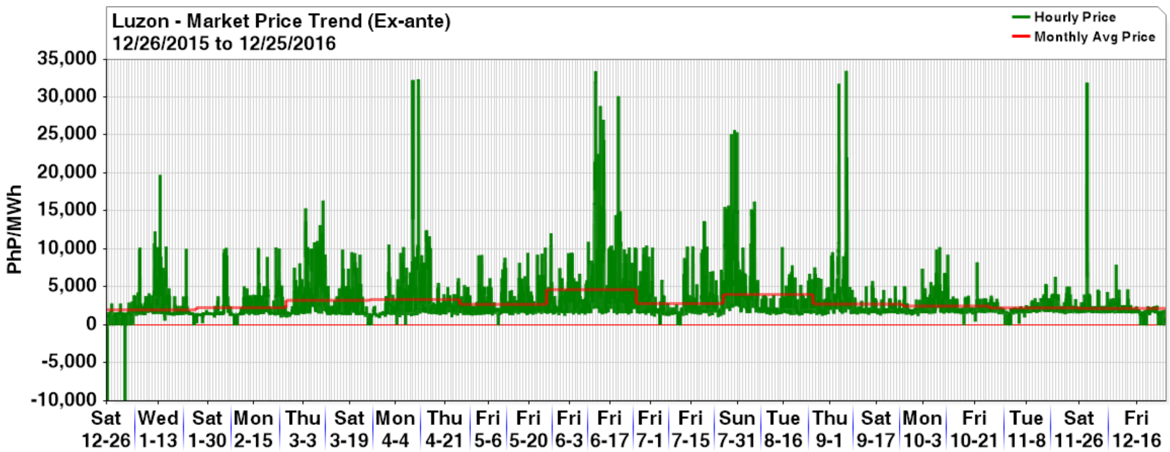


Figure 28. Market Price Trend – Visayas

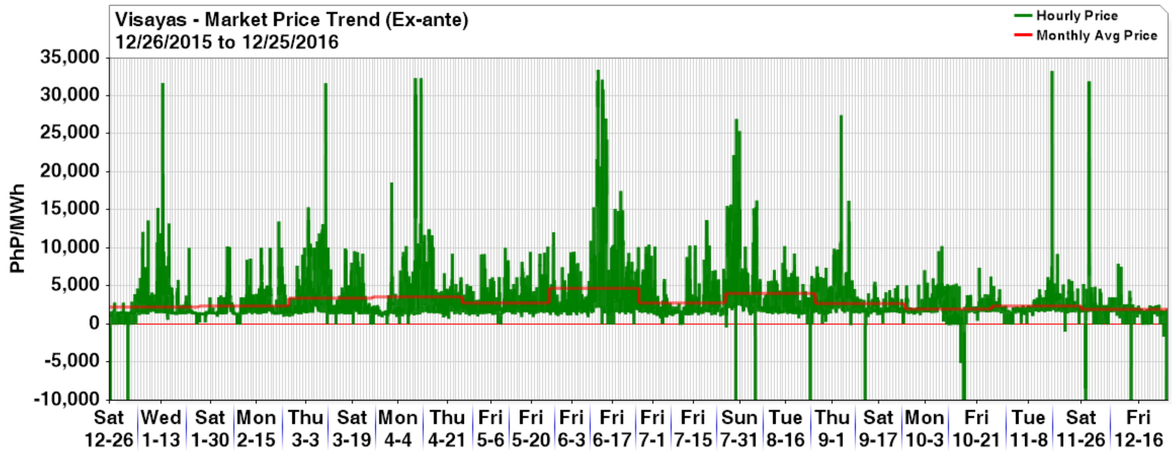


Table 38. Regional Price Summary

	Regional Price Summary - 2016												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
	Luzon (PhP/MWh)												
Max	19,789	10,233	16,406	32,423	10,208	33,467	13,725	25,687	33,530	10,271	6,362	31,945	33,530
Min	(100,654)	0	0	0	0	1,234	0	1,250	1,238	0	(0)	0	(100,654)
Avg	1,991	2,288	3,274	3,373	2,725	4,685	2,841	4,043	2,771	2,507	2,272	2,185	2,945
	Visayas (PhP/MWh)												
Max	31,730	13,518	31,712	32,373	10,208	33,467	13,725	27,010	27,504	10,271	33,329	31,945	33,467
Min	(100,654)	0	0	0	0	0	(75)	(10,200)	(10,579)	(10,329)	(963)	(13,608)	(100,654)
Avg	2,284	2,401	3,426	3,616	2,801	4,731	2,812	4,065	2,733	2,017	2,416	1,955	2,962

Table 39. Year-on-Year Average Price Trend Comparison

	Year-on-Year Market Price Trend Comparison (PhP/MWh)												
	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Avg
	Luzon (PhP/MWh)												
2016	1,991	2,288	3,274	3,373	2,725	4,685	2,841	4,043	2,771	2,507	2,272	2,185	2,945
2015	3,364	5,073	5,066	2,810	4,457	6,326	4,521	3,691	2,149	2,449	3,158	2,490	3,799
(%) Change	(40.8)	(54.9)	(35.4)	20.0	(38.9)	(25.9)	(37.2)	9.5	28.9	2.3	(28.1)	(12.2)	(22.5)
	Visayas (PhP/MWh)												
2016	2,284	2,401	3,426	3,616	2,801	4,731	2,812	4,065	2,733	2,017	2,416	1,955	2,962
2015	3,474	5,260	5,328	2,905	4,839	6,871	4,190	3,953	2,277	2,999	3,736	2,470	3,996
(%) Change	(34.3)	(54.3)	(35.7)	24.5	(42.1)	(31.1)	(32.9)	2.8	20.0	(32.8)	(35.3)	(20.8)	(25.9)

B. Frequency and Distribution

Majority of the market prices during the year were distributed within the range of above PhP0/MWh to PhP4,000/MWh, accounting for about 86.1 percent of the market prices in the current year. Meanwhile, about 9.7 percent were prices above PhP4,000/MWh to PhP10,000/MWh, while 2.7 percent were prices above PhP10,000/MWh. The remaining 1.5 percent were prices ranging from PhP0/MWh and below, including the negative prices in the market, most of which were observed during the January billing month.

Month-on-month comparison of market price distribution showed increases in the prices distributed above PhP10,000/MWh during the billing months of June and August at 9.4 percent and 9.5 percent, respectively. The same is consistent with the higher market prices observed during these months. Prices above PhP10,000/MWh were likewise relatively higher in frequency during the March and April billing months at 3 percent and 4.2 percent, respectively, as compared with the remaining months which recorded its distribution at this level from 0.1 percent to 1.8 percent only.

Conversely, the January and February billing months recorded a high of 61.3 percent and 67.3 percent in prices distributed above PhP0/MWh to PhP2,000/MWh. Further, the January and December billing months posted a high of 8.1 percent and 3.8 percent in the distribution of prices from PhP0/MWh and below, demonstrating that market prices were generally lower during these months when compared with the rest of the billing months.

Figure 29. Monthly Market Price Distribution – System

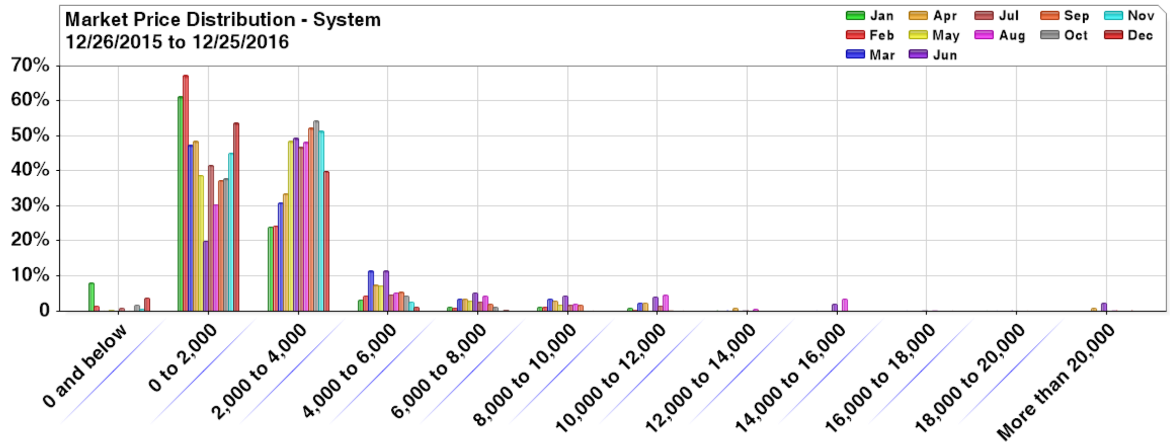


Table 40. Monthly Market Price Distribution – System

Price Range (PhP/MWh)	Market Price Distribution by Billing Month - 2016, System												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
0 and below	8.1	1.3	0.3	0.1	0.6	-	0.8	0.1	0.1	1.8	0.7	3.8	1.5
0 to 2,000	61.3	67.3	47.4	48.5	38.9	20.0	41.7	30.5	37.4	37.8	45.2	53.8	44.1
2,000 to 4,000	24.1	24.3	30.9	33.5	48.5	49.3	46.8	48.3	52.3	54.4	51.3	40.0	42.0
4,000 to 6,000	3.1	4.4	11.5	7.4	7.4	11.6	4.7	5.2	5.4	4.4	2.6	1.3	5.7
6,000 to 8,000	1.2	0.9	3.4	3.4	2.8	5.2	2.5	4.3	1.9	1.1	0.1	0.6	2.3
8,000 to 10,000	1.1	1.1	3.4	3.0	1.8	4.4	1.7	2.0	1.6	0.3	0.1	0.1	1.7
10,000 to 12,000	0.8	0.5	2.3	2.4	0.1	4.2	1.5	4.6	0.4	0.1	-	0.1	1.4
12,000 to 14,000	0.3	-	0.3	0.8	-	0.4	0.3	0.7	0.3	-	-	-	0.3
14,000 to 16,000	-	-	0.1	-	-	1.9	-	3.5	0.3	-	-	-	0.5
16,000 to 18,000	-	-	0.1	-	-	0.4	-	0.4	-	-	-	0.1	0.1
18,000 to 20,000	0.1	-	0.1	-	-	0.3	-	-	0.1	-	-	-	0.1
More than 20,000	-	-	-	0.9	-	2.3	-	0.4	0.3	-	-	0.3	0.4

Distribution of regional market prices demonstrate that prices mostly ranged above PhP0/MWh to PhP4,000/MWh in both the Luzon and Visayas.

In the Luzon region, about 1.3 percent of the prices ranged from PhP0/MWh and below, while the majority or about 86.7 percent comprised of prices above PhP0/MWh to PhP4,000/MWh. On the other hand, prices above PhP4,000/MWh to PhP8,000/MWh were at 7.6 percent while 3.2 percent were attributed to prices above PhP8,000/MWh to PhP12,000/MWh. Prices above PhP12,000/MWh to PhP20,000/MWh accounted for 0.9 percent, and prices above PhP20,000/MWh were at 0.4 percent.

As compared with Luzon, distribution of market prices in the Visayas region showed higher frequency of prices at PhP0/MWh and below at 2.9 percent, while prices above PhP0/MWh to PhP4,000/MWh likewise constitute the bulk at 83.4 percent. This notwithstanding, market prices distributed within the higher price ranges were observed more frequently in the Visayas than in Luzon. As shown in the Figure and table below, market prices above Ph4,000/MWh to PhP8,000/MWh accounted for about 9 percent of the market prices in the region. Meanwhile, about 3.2 percent were market prices above PhP8,000/MWh to PhP12,000/MWh. Further, about 1.1 percent were prices distributed above PhP12,000/MWh to PhP20,000/MWh while prices above PhP20,000/MWh comprised about 0.4 percent.

Figure 30. Regional Market Price Distribution

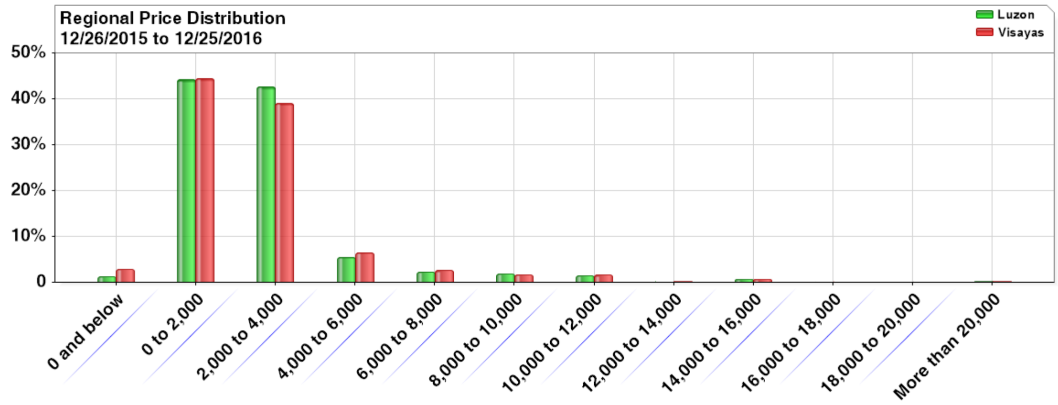


Table 41. Monthly Market Price Distribution – Luzon

Price Range (PhP/MWh)	Market Price Distribution by Billing Month - 2016, Luzon												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
0 and below	8.1	1.3	0.3	0.1	0.6	-	0.8	-	-	0.1	0.7	3.3	1.3
0 to 2,000	63.2	67.5	47.6	50.3	40.0	20.0	41.5	30.9	35.6	34.4	45.3	53.1	44.1
2,000 to 4,000	22.8	25.0	30.7	32.1	47.5	50.0	47.4	48.5	54.4	59.6	51.3	41.1	42.5
4,000 to 6,000	2.4	3.9	11.6	7.0	7.5	10.9	3.9	5.1	5.0	4.0	2.6	1.4	5.4
6,000 to 8,000	1.3	0.7	3.4	3.2	2.5	4.7	2.8	4.0	2.0	1.3	0.1	0.4	2.2
8,000 to 10,000	1.1	1.1	3.2	3.2	1.8	5.0	1.5	1.9	1.6	0.4	-	0.1	1.7
10,000 to 12,000	0.8	0.5	2.3	2.3	0.1	4.6	1.8	4.4	0.4	0.1	-	0.1	1.5
12,000 to 14,000	0.1	-	0.4	0.8	-	0.3	0.3	0.4	-	-	-	-	0.2
14,000 to 16,000	-	-	0.1	-	-	1.7	-	4.0	0.5	-	-	0.1	0.6
16,000 to 18,000	-	-	0.3	-	-	0.3	-	0.3	-	-	-	-	0.1
18,000 to 20,000	0.1	-	-	-	-	0.3	-	-	-	-	-	-	0.0
More than 20,000	-	-	-	0.9	-	2.3	-	0.4	0.4	-	-	0.3	0.4

Table 42. Monthly Market Price Distribution – Visayas

Price Range (PhP/MWh)	Market Price Distribution by Billing Month - 2016, Visayas												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
0 and below	8.1	1.3	0.4	0.3	0.6	0.5	0.8	1.7	1.9	10.3	0.8	7.8	2.9
0 to 2,000	59.9	64.4	45.7	48.1	39.3	23.4	46.4	32.9	36.6	37.9	44.8	53.6	44.4
2,000 to 4,000	21.9	26.7	31.9	30.4	46.1	46.1	41.0	42.2	50.0	46.3	49.5	35.8	39.0
4,000 to 6,000	4.3	4.4	10.3	9.9	8.6	10.9	5.8	7.0	6.3	4.4	4.3	1.4	6.5
6,000 to 8,000	2.6	1.2	4.2	3.5	3.5	5.0	2.8	3.9	2.4	0.7	0.3	0.6	2.5
8,000 to 10,000	1.5	0.8	3.6	3.2	1.7	4.3	1.3	1.7	1.7	0.3	0.1	0.1	1.7
10,000 to 12,000	0.8	0.9	2.7	2.6	0.3	3.9	1.7	4.6	0.5	0.1	-	0.1	1.5
12,000 to 14,000	0.4	0.1	0.7	0.9	-	0.5	0.3	0.7	0.3	-	0.1	0.1	0.4
14,000 to 16,000	0.1	-	0.1	-	-	1.7	-	4.4	-	-	-	-	0.5
16,000 to 18,000	-	-	0.1	-	-	0.9	-	0.3	0.1	-	-	-	0.1
18,000 to 20,000	0.3	-	-	0.1	-	0.3	-	0.1	-	-	-	-	0.1
More than 20,000	0.1	-	0.1	0.9	-	2.4	-	0.4	0.1	-	0.1	0.4	0.4

C. Summary of Pricing Errors

Non-congestion pricing errors continued to manifest during the year, occurring in about 32.1 percent of the time in the ex-ante runs (2,818 trading intervals) and 6.8 percent of the time in the ex-post runs (598 intervals).

In Luzon, issuances of non-congestion pricing errors in the ex-ante were noted in 26.4 percent of the time, affecting a total of 2,319 trading intervals. These were largely attributed to the localized contingency constraint violation on the Zapote transformers as well as input data concerns. The highest monthly occurrence of ex-ante non-congestion pricing errors was observed in May, in about 44.9 percent of the time during the billing month (323 trading intervals). On the other hand, ex-post non-congestion pricing errors in the region occurred in about 1.6 percent of the time (143 trading intervals).

In the Visayas, the frequency of issuances of non-congestion pricing errors in the ex-ante was mostly attributed to inappropriate input data concerns. Non-congestion pricing errors in the region were noted in 0.9 percent of the time in the ex-ante runs (81 trading intervals), and in 0.8 percent of the time in the ex-post (67 trading intervals).

Meanwhile, system-wide application of Price Substitution Methodology (PSM) affected a total of 1,533 trading intervals in the ex-ante (17.5 percent of the time during the year) and 1,527 trading intervals in the ex-post (17.4 percent of the time). The August billing month recorded the highest number of system-wide PSM application both in the ex-ante and in the ex-post, affecting a total of 367 and 381 trading intervals, respectively, and accounting for about 32.9 percent and 40.1 percent of the total trading intervals during the month. These were mainly due to the constraint on New Naga-Quiot line and the Bacolod-Barotac Viejo line 1 in the August billing month.

Figure 31. PEN Monthly Frequency Summary – 2016

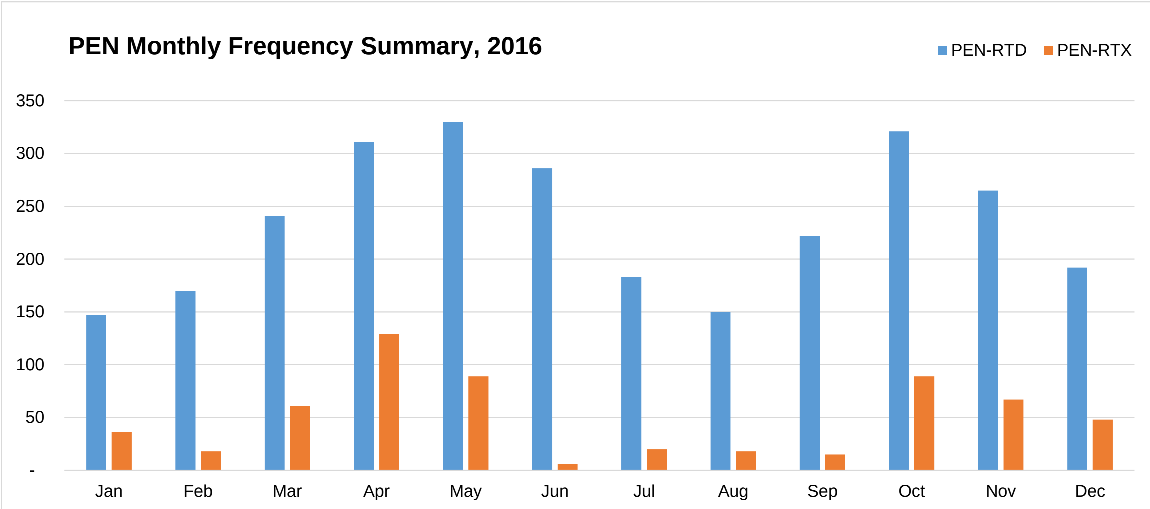


Figure 32. PSM Monthly Frequency Summary – 2016

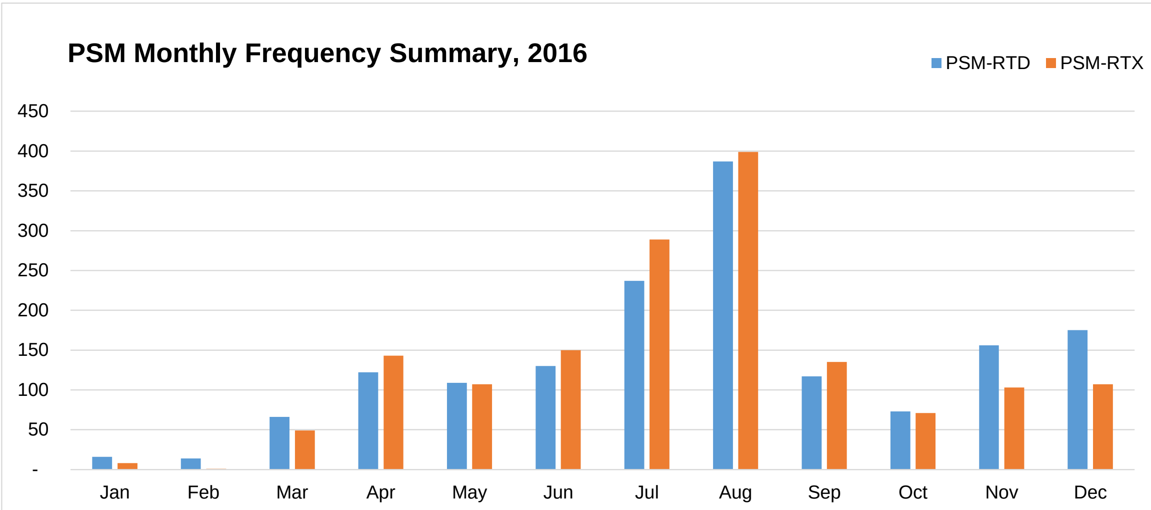


Table 43. PEN-PSM Summary

	PEN-PSM Summary - 2016																							
	Jan		Feb		Mar		Apr		May		Jun		Jul		Aug		Sep		Oct		Nov		Dec	
	Freq	%	Freq	%	Freq	%	Freq	%	Freq	%	Freq	%	Freq	%	Freq	%	Freq	%	Freq	%	Freq	%	Freq	%
	Total																							
PEN (RTD)	147	19.8	170	22.8	241	34.6	311	41.8	330	45.8	286	38.4	183	25.4	150	20.2	222	29.8	321	44.6	265	35.6	192	26.7
PEN (RTX)	36	4.8	18	2.4	61	8.8	129	17.3	89	12.4	6	0.8	20	2.8	18	2.4	15	2.0	89	12.4	67	9.0	48	6.7
PSM (RTD)	16	2.2	14	1.9	66	9.5	122	16.4	109	15.1	130	17.5	237	32.9	387	52.0	117	15.7	73	10.1	156	21.0	175	24.3
PSM (RTX)	8	1.1	1	0.1	49	7.0	143	19.2	107	14.9	150	20.2	289	40.1	399	53.6	135	18.1	71	9.9	103	13.8	107	14.9
	System																							
PEN (RTD)	5	0.7	15	2.0	79	11.4	119	16.0	7	1.0	15	2.0	34	4.7	40	5.4	6	0.8	68	9.4	60	8.1	26	3.6
PEN (RTX)	10	1.3	18	2.4	58	8.3	91	12.2	9	1.3	6	0.8	18	2.5	15	2.0	12	1.6	64	8.9	54	7.3	31	4.3
PSM (RTD)	16	2.2	14	1.9	66	9.5	121	16.3	109	15.1	130	17.5	237	32.9	367	49.3	108	14.5	67	9.3	154	20.7	144	20.0
PSM (RTX)	8	1.1	1	0.1	49	7.0	143	19.2	107	14.9	150	20.2	289	40.1	381	51.2	131	17.6	68	9.4	101	13.6	99	13.8
	Luzon																							
PEN (RTD)	134	18.0	155	20.8	159	22.8	188	25.3	323	44.9	271	36.4	149	20.7	109	14.7	215	28.9	248	34.4	204	27.4	164	22.8
PEN (RTX)	-	-	-	-	1	0.1	27	3.6	80	11.1		-		-	1	0.1		-	20	2.8	10	1.3	4	0.6
PSM (RTD)	-	-	-	-	-	-		-		-		-		-	1	0.1		-	6	0.8		-	2	0.3
PSM (RTX)	-	-	-	-	-	-		-		-		-		-		-		-	3	0.4		-	-	-
	Visayas																							
PEN (RTD)	29	3.9	-	-	19	2.7	12	1.6	1	0.1		-	1	0.1	1	0.1	3	0.4	7	1.0	2	0.3	6	0.8
PEN (RTX)	26	3.5	-	-	2	0.3	12	1.6		-		-		-	2	0.3	3	0.4	6	0.8	3	0.4	13	1.8
PSM (RTD)	-	-	-	-	-	-	1	0.1		-		-		-	19	2.6	9	1.2		-	2	0.3	29	4.0
PSM (RTX)	-	-	-	-	-	-		-		-		-		-	18	2.4	4	0.5		-	2	0.3	8	1.1

D. Interesting Pricing Events

This section provides an analysis of market prices relative to the level of supply margin in the market for the year 2016.

Supply margin is defined as the MW difference between the system effective supply and demand requirement plus reserve schedules. For the purpose of this report, interesting pricing events refer to intervals determined to have price outliers based on the relationship of market price and supply margin. Based on economic theory, prices tend to go up if the supply margin is low and go down if the supply margin is high. When the market price does not reflect the supply margin level, the resulting price level can be thought as “abnormal or interesting”, and is therefore subject to further scrutiny. The relationship of supply margin and price is another monitoring metric used to identify any unusual market outcome with a general intent of further assessing a rather unusual event.

Figure 33 shows the scatterplot of supply margin and price during the covered period. Consistent with the economic theory, high prices were noted during low levels of supply margin or tight supply condition. On the other hand, low prices were observed during periods with wide or comfortable levels of supply margin.

Table 44 provides the summary of the supply margin distribution and the corresponding price in various forms. Of the 8,730 intervals, 213 intervals (2.4 percent of the time) have supply margin below 250 MW, with price ranging from PhP 5,145/MWh to PhP 33,467/MWh. Further, the level of supply margin, ranging from 1,000 MW to 1,500 MW was recorded for 21 percent of the time with price ranging from PhP 2,3744/MWh to PhP 8,202/MWh. Wide supply margin (3,000 MW and above) was also observed in 581 intervals (7 percent of the time) with prices between negative PhP 100,654/MWh to PhP 2,049/MWh.

Figure 33. Supply Margin vs Market Price-System, 2016

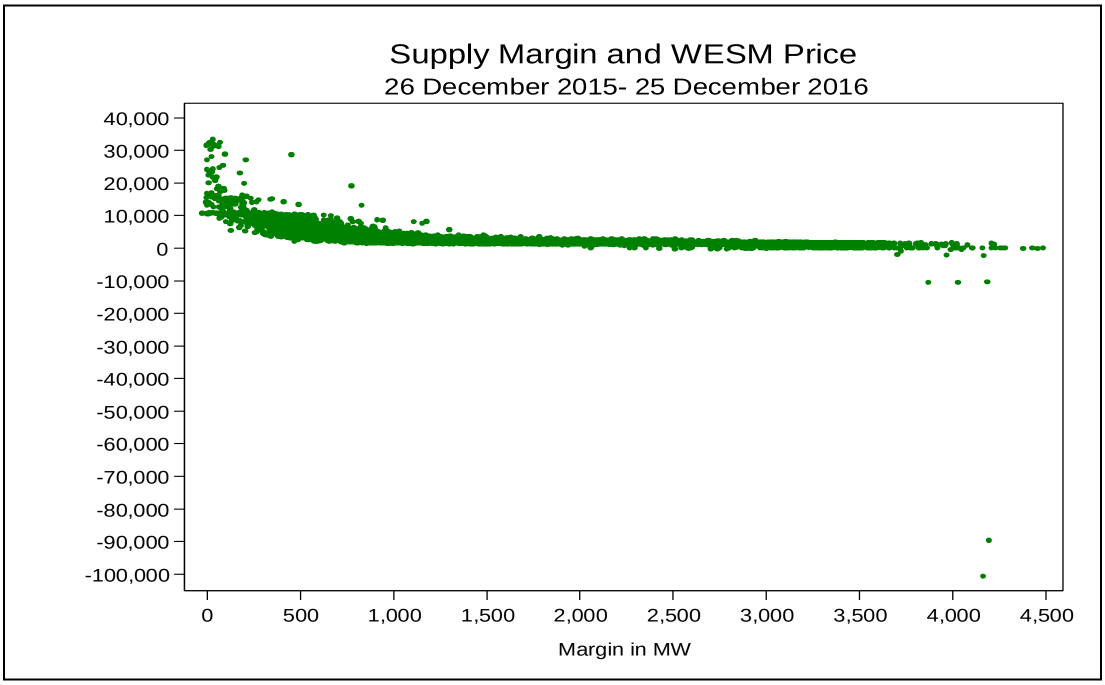


Table 44. Supply Margin Distribution and Market Price- System, 2016

Range (in MW)	Supply Margin		Price(PhP/MWh)		
	No. of Intervals	% of the Time	Max	Min	Ave
0 to 250	213	2.44	33,467	5,145	13,810
250 to 500	389	4.46	28,710	2,007	7,036
500 to 750	738	8.45	10,218	1,692	4,433
750 to 1000	1,063	12.18	19,194	1,458	3,227
1,000 to 1,500	1,818	20.82	8,202	1,318	2,374
1,500 to 2000	1,656	18.97	3,559	1,000	1,964
2,000 to 2,500	1,491	17.08	2,851	(170)	1,702
2,500 to 3000	781	8.95	2,831	(334)	1,517
3,000 and above	581	6.66	2,049	(100,654)	695
Total	**8,730.00**	**100**	**33,467**	**(100,654)**	**2,919**

Note: Number of intervals excludes those with market intervention/suspension.

To determine the interesting pricing events, a combination of statistical methods namely, bandwidth method, ordinary least squares (OLS) method and non-parametric method was used to create the upper and lower reference price thresholds. Prices within the upper and lower reference price thresholds are considered as “normal prices”, while prices outside the thresholds are tagged as “interesting pricing events”.

The criteria used in the assessment were as follows: (a) A reference threshold was set to only include the period from 26 December 2013 to 25 December 2016 when the PhP 32,000/MWh offer price cap was adopted; (b) upper and lower reference price thresholds were computed using ±3 percent standard deviations to provide a reasonable tolerance price levels; and (c) intervals with market intervention/suspension; and (d) intervals with negative supply margin and load shedding were excluded to only include intervals without under-generation. The computed reference price thresholds are provided in Table 45 below.

Table 45. Supply Margin Distribution and Price Thresholds

Supply Margin Range (in MW)	Price Thresholds	
	Upper (PhP/MWh)	Lower (PhP/MWh)
0 to 250	22,025.70	(155.91)
250 to 500	19,273.79	(2,907.46)
500 to 750	17,448.17	(4,732.88)
750 to 1000	16,121.85	(6,059.12)
1,000 to 1,250	15,145.13	(7,035.81)
1,250 to 1,500	14,405.27	(7,775.67)
1,500 to 1,750	13,779.32	(8,401.63)
1,750 to 2,000	13,221.78	(8,959.19)
2,000 to 2,250	12,735.07	(9,445.90)
2,250 to 2,500	12,327.69	(9,853.29)
2,500 to 2,750	11,993.89	(10,187.14)
2,750 to 3,000	11,703.91	(10,477.24)
3,000 and above	11,733.76	(10,455.30)

As illustrated in Figure 34, there were 25 intervals wherein prices went above the upper reference price threshold. This number is lower than the identified 39 intervals that were tagged as interesting pricing events in 2015. On the other hand, two (2) intervals were noted to have prices below the lower reference threshold. It is noteworthy to mention that these price outliers happened before the effectivity of the offer floor of negative PhP10,000 on 01 January 2016 following the issuance of ERC of Resolution No. 3 s.2015. Details of the interesting pricing events are provided in Table 46 below.

Figure 34. Supply Margin and Market Price-System, 2016

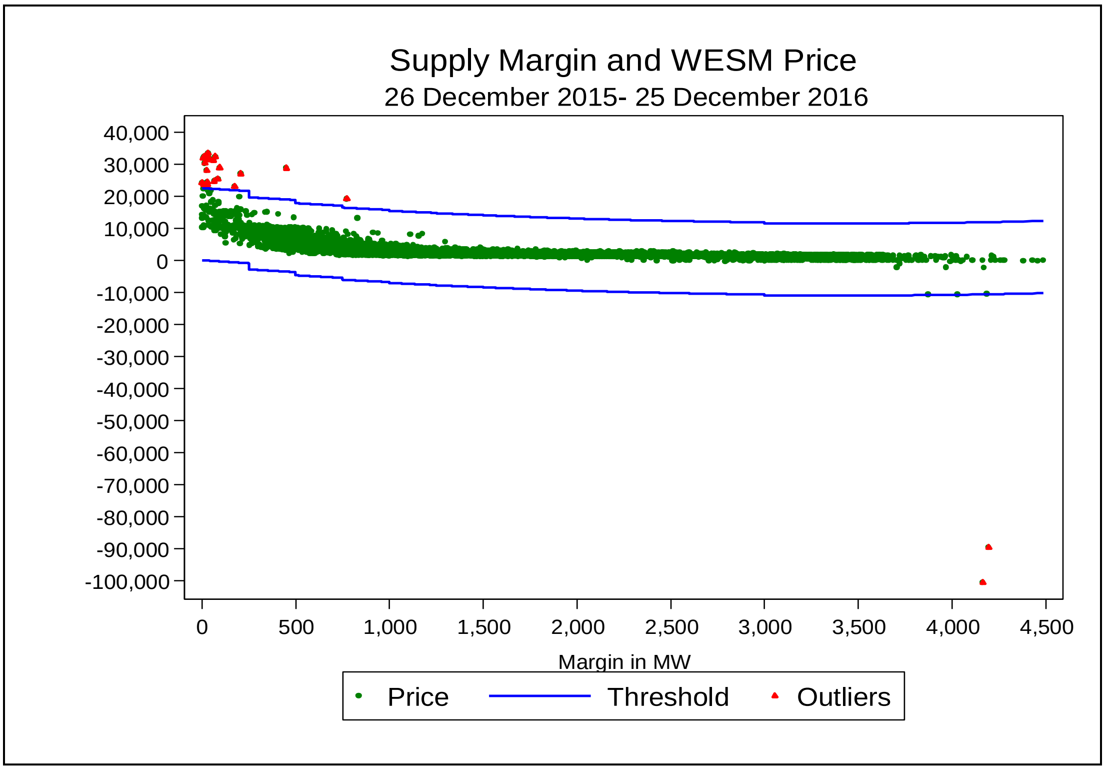


Table 46. List of Interesting Price Events, 2016

Date	Hour	Price (PhP/MWh)	Margin (MW)	Price Setter (Resource Name)
Outliers- Upper Price Reference Threshold				
9-Apr-16	19	32,303	15	Pantabangan HEP, Angat HEP
9-Apr-16	21	31,970	8	Pantabangan HEP, TPC (Carmen) DPP
11-Apr-16	17	32,415	14	Pantabangan HEP
11-Apr-16	18	32,209	12	Pantabangan HEP
11-Apr-16	19	32,251	15	Pantabangan HEP
11-Apr-16	20	30,299	16	Subic DPP, CIP DPP
11-Apr-16	21	24,395	30	Bauang DPP, CIP DPP
11-Jun-16	19	23,548	29	Kalayaan PSPP
11-Jun-16	21	31,498	41	Kalayaan PSPP, TPC (Carmen) DPP
11-Jun-16	22	31,411	35	Kalayaan PSPP, TPC (Carmen) DPP
11-Jun-16	23	33,467	32	Limay CCGT, TPC (Carmen) DPP
11-Jun-16	24	32,326	71	Limay CCGT
13-Jun-16	14	28,880	95	No price setter
14-Jun-16	19	24,131	1	Calumangan DPP
14-Jun-16	20	23,665	10	Kalayaan PSPP, PB 101, PB 102
19-Jun-16	19	28,063	26	Bauang DPP
19-Jun-16	20	26,972	207	Bauang DPP, Magat HEP
28-Jul-16	20	24,666	66	Bauang DPP,Kalayaan PSPP, PB 102
29-Jul-16	23	23,051	175	CIP DPP, Bauang DPP, CPPC DPP,PEDC CFTPP
30-Jul-16	19	25,392	84	PEDC CFTPP
3-Sep-16	23	31,146	62	PCPC CFTPP, TPC (Carmen) DPP
6-Sep-16	13	28,710	451	Bauang DPP, TPC (Carmen) DPP
6-Sep-16	18	19,194	773	Bauang DPP, TPC (Carmen DPP
28-Nov-16	15	31,913	36	Anda CFTPP
28-Nov-16	18	31,945	32	No price setter
Outliers- Lower Price Reference Threshold				
26-Dec-15	4	(100,654)	4,165	Angat HEP
26-Dec-15	6	(89,664)	4,197	Angat HEP, CEDC CFTPP, KSPC CFTPP

Higher-priced oil-based and hydro plants were the dominant resource types that set the prices during the interesting pricing events.

Market prices above PhP30,000/MWh were noted in April – on 09 April at 1900H and 2100H and on 11 April at 1700H-2100H as a result of high demand requirement during low supply periods. Supply margin dropped to as low as 8 MW with the forced outage of the 647-MW Sual CFTPP 2, on top of the existing outages of major coal plants.

Meanwhile, the month of June recorded the most number of price outliers with 10 out of the 27 interesting pricing events above the upper reference price threshold. As previously discussed, the said month was marked with tight supply condition, while electricity demand remained relatively high. In particular, on 11-19 June 2016 major coal plants simultaneously went on outage, resulting to the dispatch of higher-priced plants. The outage capacity in June averaged at 1,898 MW. Moreover, it was noted that the June billing period posted a relatively higher level of capacity gap, averaging at 3,030 MW, when compared to the capacity gap in the other billing periods, except for April May and July.

On the other hand, high market prices were observed in some intervals on 28 -30 July 2016 due to low supply levels. The said period saw an increasing events of unscheduled outages of several major power plants in the Luzon region resulting in lack of power supply. Consequently, the National Grid Corporation of the Philippines-System Operator (NGCP-SO) placed the region under yellow alert and red alert status. The August billing month posted the highest capacity on outage, averaging at 2,573 MW.

Simultaneous outages of major natural and coal plants was also the main reason why market prices on 03 September at 2300H and on 28 November at 1500H and 1800H went beyond reference the upper reference price threshold. As previously discussed, market prices went above the PhP30,000/MWh mark during said intervals, despite the lower prices recorded during the month.

Based on the foregoing discussions, the identified higher than usual market price outcomes were mainly driven by the limited supply available in the market. The tight supply condition was largely attributed to the frequent and unplanned outages of major generating plants. It is noteworthy to mention that a high level of capacity gap, averaging at 2,751 MW in 2016, likewise contributed to the overall supply level in the market and resulting market price.

VIII. MARKET INTERVENTION/SUSPENSION[29]

System-wide market intervention (MI) affected a total of 23 trading intervals across the 2016 billing year in both the Luzon and Visayas regions, all of which were initiated by the Market Operator (MO) on account of force majeure due to Market Management System (MMS)[30] concerns.

Meanwhile, 24 MI events were declared in Luzon. Of which, 2 were attributed to MO-initiated events due to MMS concerns while the remaining 22 were MI events initiated by the System Operator (SO) due to emergency/security events. Note that 14 of these occurred during the August billing month, in time with the SO's recurring declaration of yellow and red alert status in the Luzon grid, as discussed in preceding sections.

On the other hand, there was no MI event in the Visayas grid during the year.

Table 47. Total Monthly Occurrences of Market Intervention

Initiated by	Remarks (Luz-Vis)	2016												
		Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
MO	Force Majeure (MMS Concern)	7	1		12	1				1		1		23
	Force Majeure (MO Other Concern)													0
	Force Majeure (SCADA/EMS Concern)													0
	Sub-Total (MO-Initiated)	7	1	0	12	1	0	0	0	1	0	1	0	23
NGCP-SO	Emergency/Security Event													0
	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	0
ERC	Declaration of Market Suspension													0
	Sub-Total (ERC-Initiated)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total		**7**	**1**	**0**	**12**	**1**	**0**	**0**	**0**	**1**	**0**	**1**	**0**	**23**

Table 48. Monthly Occurrences of Market Intervention – Luzon

Initiated by	Remarks (Luzon)	2016												
		Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
MO	Force Majeure (MMS Concern)			1	1									2
	Force Majeure (MO Other Concern)													0
	Sub-Total (MO-Initiated)	0	0	1	1	0	0	0	0	0	0	0	0	2
NGCP-SO	Emergency/Security Event								14	4		4		22
	Force Majeure (SCADA/EMS Concern)													0
	Force Majeure (SO Other Concern)													0
	Sub-Total (NGCP-SO-Initiated)	0	0	0	0	0	0	0	14	4	0	4	0	**22**
ERC	Declaration of Market Suspension													0
	Sub-Total (ERC-Initiated)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total		**0**	**0**	**1**	**1**	**0**	**0**	**0**	**14**	**4**	**0**	**4**	**0**	**24**

[29] 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 shall be used for WESM settlement.

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.

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

IX. PRICE SETTING FREQUENCY INDEX (PSFI)[31]

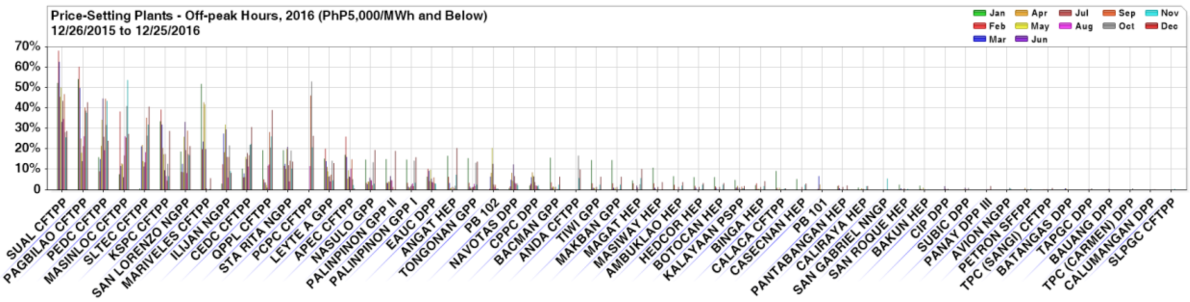
The succeeding charts show the generating plants that qualified as price setters as well as the frequency that they became such during year. The PSFI are determined for several price ranges. For purposes of this Report, price-setting plants are identified together with their respective major participant groups.

As shown in the Figure below, coal plants dominated the list of 55 generating plants that qualified as price-setters within the range of PhP5,000/MWh and below, with more plants setting the price at this level during off-peak hours.

Major coal plants from Luzon Sual CFTPP and Pagbilao CFTPP, which are associated with major participant groups San Miguel Corporation (SMC) and Aboitiz Power (AP), topped the list of off-peak price-setters, setting the price at PhP5,000/MWh and below at about 43.2 percent and 35.9 percent during the year. Visayas coal plant PEDC CFTPP, grouped under Global Business Power Corporation (GBPC) came next at about 27.5 percent followed by Luzon coal plants Masinloc CFTPP of Masinloc Power Partners Corporation (MPPC) at 23.6 percent, Trans-Asia Oil and Energy Development Corporation's (TAOEDC) SLTEC CFTPP, at 19.8 percent and Visayas coal plant KSPC CFTPP of Salcon Power Corporation (SPC) at 19.1 percent. First Gen Corporation's (FGC) San Lorenzo NGPP, Mariveles CFTPP under the GNPower Mariveles Coal Plant Ltd. Corporation (GMCP), SMC's Ilijan NGPP, GBPC's CEDC CFTPP, Quezon Power Partners Limited Corporation's QPPL CFTPP, FGC's Sta. Rita NGPP and Palm Concepcion Power Corporation's PCPC CFTPP likewise figured in the list with a PSFI of about 18.4 percent, 17.1 percent, 16.4 percent, 15.4 percent, 14.8 percent, 14 percent and 13.5 percent, respectively.

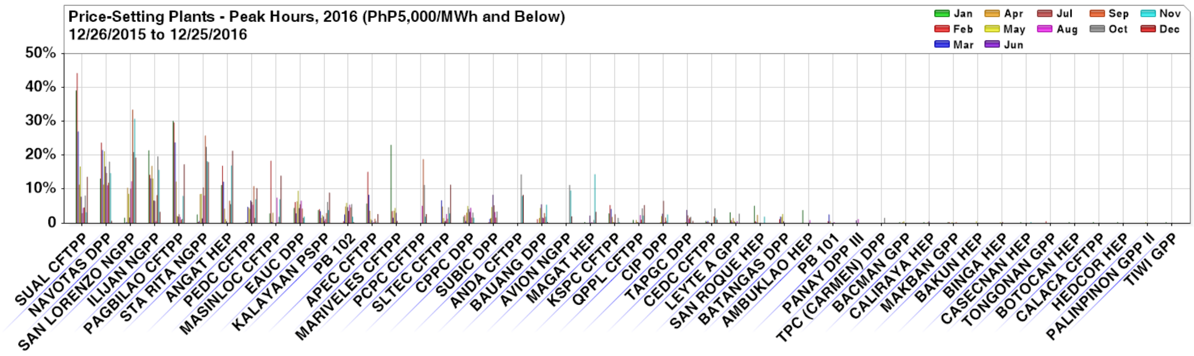
On the other hand, the price-setting plants during peak hours within the PhP5,000/MWh and below range set the price at a lower frequency. SMC's Sual CFTPP was also the most frequent price-setter among 46 price-setting plants, posting its PSFI at 15.4 percent across the year during peak hours, followed by oil-based plant Navotas DPP under the AP group at 15.1 percent, FGC's San Lorenzo NGPP at 12.2 percent, SMC's Ilijan NGPP at 11.6 percent, AP's Pagbilao CFTPP at 10.9 percent and FGC's Sta. Rita NGPP at 10.2 percent.

Figure 35. Price-Setting Plants – Off-peak Hours (PhP5,000/MWh and Below)



[31] 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.

Figure 36. Price-Setting Plants – Peak Hours (PhP5,000/MWh and Below)



Meanwhile, price-setters within the higher price range of above PhP5,000/MWh to PhP10,000/MWh were mostly oil-based and hydro plants.

Seventeen (17) oil-based plants dominated the list of 26 price-setters during off-peak hours, topped by Visayas plants PB 101 DPP of the TAOEDC group and GBPC's TPC (Carmen) DPP with PSFIs of 2.5 percent and 2.1 percent during the year. They were followed by more oil-based plants from the Visayas namely: AP's EAUC DPP at 1.4 percent, SPC's Panay DPP III at 1.3 percent, GBPC's Nabas DPP and TAOEDC's PB 102 DPP at 1.2 percent, and AP's CPPC DPP at 1.1 percent. Luzon oil-based plant Bauang DPP of Vivant Energy Corporation (VEC) came next with 0.9 percent.

The list of 26 price-setting plants during peak hours across the year were likewise dominated by 17 oil-based plants, topped by VEC's Bauang DPP with a PSFI of 3.5 percent followed by SMC's Angat HEP with 2 percent, GBPC's TPC (Carmen) DPP at 1.9 percent, PB 101 DPP of TAOEDC at 1.6 percent, EAUC DPP of the AP group at 1.5 percent, SPC's Panay DPP III at 1 percent, AP's Magat HEP at 0.9 percent, and TAOEDC's Subic DPP at 0.8 percent.

As illustrated in Figures 37 and 38 below, it is observed that the June billing month posted the highest frequency by which plants were able to set the price at this level. The February to May billing months also posted a relatively higher frequency of price-setters at this level across the year.

Figure 37. Price-Setting Plants – Off-peak Hours (Above PhP5,000/MWh to PhP10,000/MWh)

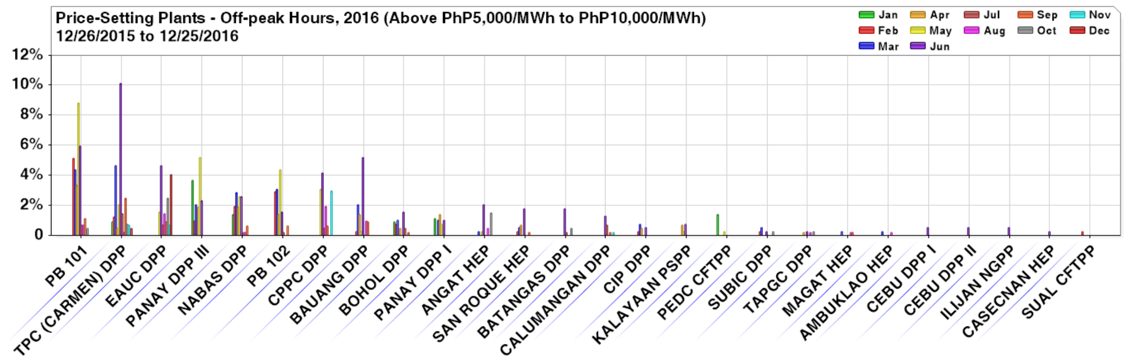
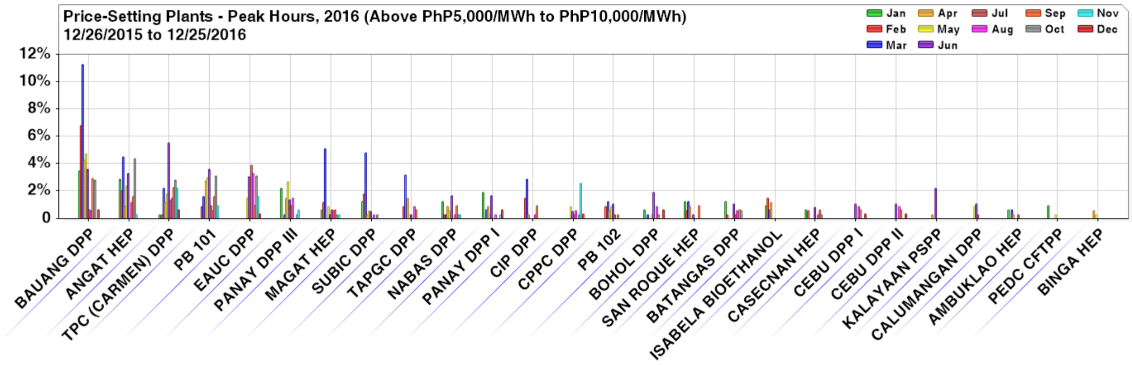


Figure 38. Price-Setting Plants – Peak Hours (Above PhP5,000/MWh to PhP10,000/MWh)



Thirteen (13) out of the 20 price-setters at above PhP10,000/MWh during peak hours were oil-based plants. The list, however, was topped by hydro plant Kalayaan PSPP of the Power Sector Asset and Liabilities Management (PSALM) which set the price at about 0.9 percent of the time during year 2016. Luzon oil-based plants Bauang DPP of VEC and Limay CCGT of Millennium Energy, Inc. (MEI) came in next with PSFI of 0.6 percent each, followed by CPPC DPP and TPC (Carmen) DPP at 0.2 percent each.

On the other hand, 14 plants were able to set the price at the above PhP10,000/MWh range during off-peak hours in 2016. Ten (10) out of these are oil-based plants. TPC (Carmen) DPP of GBPC and MEI's Limay CCGT were the top price-setters with PSFI of 0.5 percent each, followed by Bauang DPP of VEC and CPPC DPP of the AP group at 0.4 percent each. Kalayaan PSPP of PSALM likewise figured as a top off-peak price-setter at about 0.2 percent during the year.

The billing months of June and August posted the highest frequency by which plants were able to set the price at above PhP10,000/MWh, consistent with the higher market prices during these months.

Figure 39. Price-Setting Plants – Off-peak Hours (Above Php10,000/MWh)

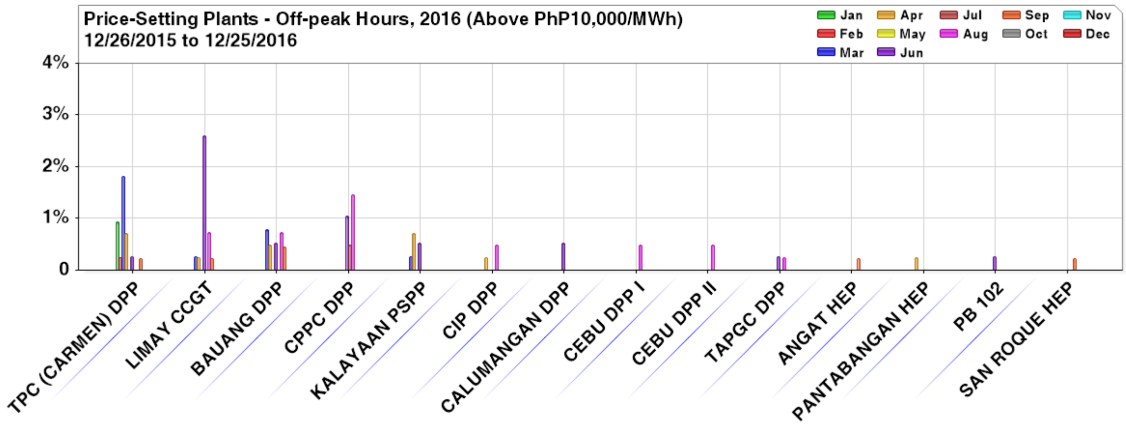
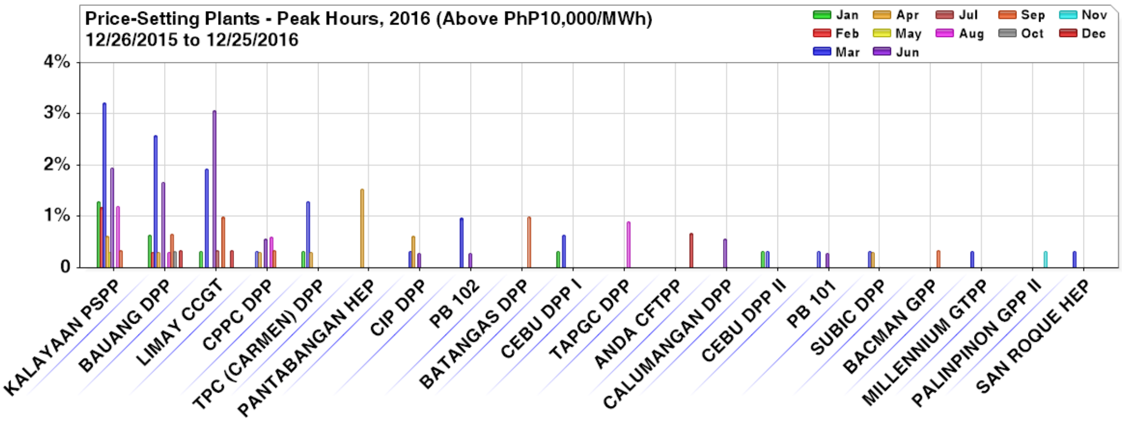


Figure 40. Price-Setting Plants – Peak Hours (Above Php10,000/MWh)



X. PIVOTAL SUPPLIER FREQUENCY INDEX[32]

Similar to the above section on price-setters, generating plants that were pivotal during the year are identified in this Report together with their respective major participant groups.

Forty-two (42) plants from Luzon and 22 plants from the Visayas became pivotal suppliers during the billing year. From the Luzon region, large generating plants Ilijan NGPP (SMC), Sual CFTPP (SMC) and Sta. Rita NGPP (FGC) topped the list of pivotal suppliers at about 44.9 percent, 42 percent and 38 percent of the time in 2016. Pagbilao CFTPP (AP) placed fourth at 29.8 percent followed by Masinloc CFTPP (MPPC) at 28.2 percent, San Lorenzo NGPP (FGC) at 25.9 percent, Mariveles CFTPP (GNPower) at 24.1 percent, QPPL CFTPP (QPPL) at 21.2 percent, Calaca CFTPP under the Semirara Mining and Power Corporation (SMPC) group at 20.3 percent, Limay CCGT (MEI) at 20 percent and hydro plants San Roque HEP (SMC) and Kalayaan PSPP (PSALM) at 18.3 percent and 18.1 percent, respectively.

On the other hand, Visayas geothermal plant Leyte A GPP (PSALM) was the most frequent pivotal supplier from the Visayas region with a PSI of about 21.8 percent followed by CEDC CFTPP (GBPC), becoming pivotal at about 17.4 percent of the time. SPC's KSPC CFTPP came next at 16.4 percent followed by GBPC's PEDC CFTPP and TPC (Sangi) at 15.8 percent, 14.6 percent, respectively, and FGC's Palinpinon GPP 1 at 14.4 percent.

The frequency by which generating plants became pivotal this year rose significantly during the June and August billing months, which were the same months marked with tight supply and demand balance. It was also observed that the May and April billing months likewise posted a relatively higher level of pivotal supply consistent with the tight reserve margin index during these months.

[32] 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.

Figure 41. Pivotal Supplier Frequency Index – Luzon Plants

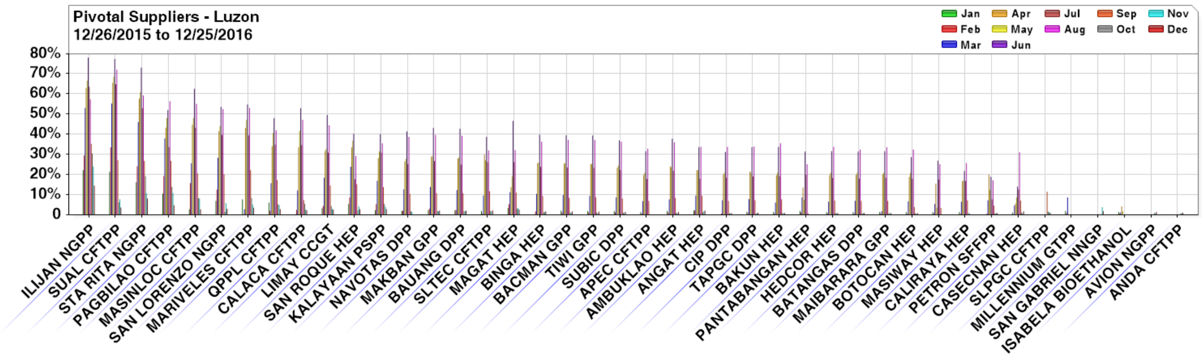


Table 49. Pivotal Supplier Frequency Index by Billing Month – Luzon Plants

Major Participant Group	Luzon Generating Plant	Pivotal Supplier Index (%) by Billing Month, 2016											
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
SMC	ILIJAN NGPP	22.2	29.4	53.0	63.0	66.7	78.1	63.6	57.4	35.2	30.4	23.9	14.4
SMC	SUAL CFTPP	21.4	33.5	55.3	65.6	68.6	77.4	64.9	72.2	27.2	6.1	7.7	3.6
FGC	STA RITA NGPP	16.1	24.1	46.1	57.8	61.0	73.1	52.9	59.3	26.7	19.2	10.8	8.1
AP	PAGBILAO CFTPP	10.5	19.2	37.9	43.3	48.1	52.0	33.6	56.5	26.7	13.9	10.8	4.7
MPPC	MASINLOC CFTPP	2.7	15.7	25.6	44.8	48.1	62.6	43.2	55.1	20.6	8.2	8.1	2.6
FGC	SAN LORENZO NGPP	6.9	12.5	28.3	41.5	44.0	53.6	39.6	52.6	20.0	1.4	5.8	2.9
GMCP	MARIVELES CFTPP	7.7	0.3	2.7	43.1	47.2	54.8	39.4	53.1	22.2	8.3	5.0	3.5
QPPL	QPPL CFTPP	6.0	2.0	15.7	34.0	40.7	48.0	34.9	41.9	17.2	5.1	4.8	2.8
SMPC	CALACA CFTPP	0.3	2.4	12.1	33.6	41.7	53.0	34.6	47.2	7.3	5.4	2.6	2.2
MEI	LIMAY CCGT	3.2	4.3	18.4	31.7	32.8	49.6	30.8	44.5	14.5	4.3	2.8	2.5
SMC	SAN ROQUE HEP	5.4	8.6	23.9	33.5	36.8	40.2	17.6	29.2	15.2	2.2	4.2	2.8
PSALM	KALAYAAN PSPP	2.3	5.2	16.8	28.1	31.5	40.1	30.8	35.5	13.7	5.4	3.9	2.8
AP	NAVOTAS DPP	1.9	2.0	12.6	26.5	27.8	41.4	25.1	38.7	10.3	1.7	1.5	
AP	MAKBAN GPP	2.3	3.0	13.8	28.9	29.2	43.1	26.7	39.7	10.8	1.8	1.6	2.1
VEC	BAUANG DPP	2.2	2.4	12.2	28.0	28.5	42.7	24.9	39.2	10.8	1.8	1.6	2.1
TAOEDC	SLTEC CFTPP	1.9	0.5	9.5	30.0	26.9	38.7	26.1	32.0	11.7	1.8	1.6	2.2
AP	MAGAT HEP	3.4	5.2	11.2	13.7	19.0	46.6	26.1	32.1	11.0	2.9	3.4	2.5
AP	BINGA HEP	0.3	1.6	10.3	25.7	26.0	39.8	23.8	36.3	9.3	1.3	1.2	1.7
FGC	BACMAN GPP	2.0	1.2	9.8	25.4	25.7	39.5	23.5	37.2	8.3	1.3	0.9	1.7
AP	TIWI GPP	1.9	1.1	9.3	25.1	25.3	39.4	23.3	37.1	8.7	1.1	0.7	1.5
TAOEDC	SUBIC DPP	1.9	1.1	8.6	23.4	24.4	37.0	22.2	36.3	8.1	1.0	0.8	1.4
APEC	APEC CFTPP	1.3	0.5	6.8	19.8	20.8	31.6	17.8	32.8	6.9	0.1		
AP	AMBUKLAO HEP	1.9	1.1	7.6	24.1	23.6	37.8	21.8	36.0	8.3	1.0	0.7	1.4
SMC	ANGAT HEP	2.2	2.2	9.5	22.2	22.1	33.6	17.9	33.7	9.4	1.3	1.6	2.1
TAOEDC	CIP DPP		0.5	7.2	20.0	20.8	31.2	18.3	33.7	6.9	0.7	0.5	0.8
TAOEDC	TAPGC DPP	1.5	0.8	7.8	21.5	20.8	33.6	19.0	33.9	7.3	0.7	0.7	1.0
VEC	BAKUN HEP	1.3	0.5	6.0	19.6	21.0	33.7	19.2	35.5	7.7	0.8	0.7	0.8
FGC	PANTABANGAN HEP	1.9	1.1	8.6	13.6	7.4	31.5	19.9	25.1	0.7			
PSALM	HEDCOR HEP	1.3	0.5	6.5	19.6	20.8	31.6	18.2	33.7	7.0	0.7	0.7	0.8
Other IPPs	BATANGAS DPP	1.3	0.5	6.9	19.9	20.8	31.5	17.9	32.4	6.9	0.7	0.7	0.8
TAOEDC	MAIBARARA GPP	1.3	0.5	1.7	20.0	20.8	31.6	18.3	33.6	6.9	0.7	0.7	0.8
PSALM	BOTOCAN HEP	1.3	0.4	6.6	18.8	20.8	28.6	17.9	32.4	3.8	0.7	0.4	0.8
PSALM	MASIWAY HEP	1.3	0.5	5.3	15.5	3.5	26.9	17.5	25.1	3.4			
PSALM	CALIRAYA HEP	1.3	0.4	6.5	16.7	16.9	21.8	16.8	25.7	7.1	0.7	0.7	
SMC	PETRON SFFPP		0.5	7.2	19.9	12.4	18.8	7.6	17.1	4.6	0.7	0.7	0.8
PSALM	CASECNAN HEP	1.1	0.1	4.6	5.5	8.6	14.0	12.5	31.0	7.0	1.1	0.7	1.7
SMPC	SLPGC CFTPP									11.4	1.5	1.2	1.0
MEI	MILLENNIUM GTPP	1.9	0.8	8.6									
FGC	SAN GABRIEL NNGP											3.8	1.8
GFII	ISABELA BIOETHANOL	1.3	0.5	1.1	4.2	1.7							
FGC	AVION NGPP										0.8	0.7	1.4
APC	ANDA CFTPP										0.8	0.7	1.0

Figure 42. Pivotal Supplier Frequency Index – Visayas Plants

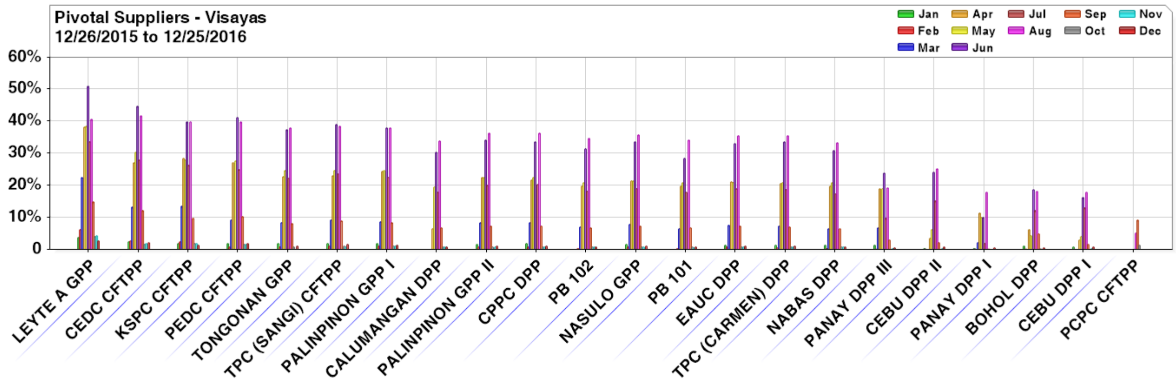


Table 50. Pivotal Supplier Frequency Index by Billing Month – Visayas Plants

Major Participant Group	Visayas Generating Plant	Pivotal Supplier Index (%) by Billing Month, 2016											
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
PSALM	LEYTE A GPP	3.8	6.3	22.4	38.3	38.5	51.1	33.8	40.6	14.9	4.0	4.3	2.8
GBPC	CEDC CFTPP	2.6	2.7	13.2	27.0	30.4	44.8	27.9	41.8	12.2	1.7	1.9	2.1
SPC	KSPC CFTPP	2.0	2.6	13.5	28.6	28.1	39.8	26.3	39.9	9.8	1.8	2.0	1.4
GBPC	PEDC CFTPP	1.9	0.9	9.3	27.3	27.6	41.4	24.9	39.8	10.3	1.5	1.7	1.8
FGC	TONGONAN GPP	1.9	0.8	8.5	22.7	24.6	37.4	22.4	38.0	8.1	0.8		1.0
GBPC	TPC (SANGI) CFTPP	2.0	1.2	9.3	23.0	24.7	39.1	23.8	38.4	8.9	1.0	0.8	1.7
FGC	PALINPINON GPP I	1.9	1.1	8.8	24.5	24.7	38.0	22.6	38.0	8.3	1.0	1.2	1.4
Other IPPs	CALUMANGAN DPP				6.6	19.6	30.4	17.9	34.0	6.9	0.7	0.9	0.8
FGC	PALINPINON GPP II	1.7	0.8	8.3	22.4	22.5	34.1	20.0	36.3	7.3	0.8	0.9	1.0
AP	CPPC DPP	1.9	0.8	8.5	21.6	22.5	33.6	20.3	36.3	7.4	0.8	0.9	1.0
TAOEDC	PB 102		0.5	7.0	19.8	20.8	31.6	18.2	34.7	6.7	0.7	0.9	0.8
FGC	NASULO GPP	1.6	0.8	7.9	21.5	21.4	33.7	19.0	35.8	7.3	0.8	0.9	1.0
TAOEDC	PB 101		0.5	6.6	19.8	20.8	28.6	17.9	34.1	6.9	0.7	0.7	0.8
AP	EAUC DPP	1.5	0.8	7.5	21.1	21.0	33.2	18.9	35.6	7.3	0.7	0.9	1.0
GBPC	TPC (CARMEN) DPP	1.5	0.7	7.3	20.7	21.0	33.6	18.8	35.6	7.1	0.8	0.9	1.0
GBPC	NABAS DPP	1.3	0.5	6.5	19.8	20.8	31.0	17.5	33.3	6.6	0.7	0.9	0.8
SPC	PANAY DPP III	1.3	0.4	6.8	19.0	19.0	23.8	9.7	19.2	3.0	0.3	0.5	0.6
SPC	CEBU DPP II	0.5	0.1		3.6	6.3	24.2	15.3	25.1	2.3	0.1	0.5	0.8
SPC	PANAY DPP I	0.5		2.3	11.4	10.1	10.1	1.9	17.9	0.4			0.6
SPC	BOHOL DPP	1.1	0.4	0.3	6.3	4.4	18.7	12.1	18.1	5.0	0.4		0.6
SPC	CEBU DPP I	0.9	0.1	0.3	3.0	4.2	16.4	13.1	18.0	1.7		0.5	0.8
PCPC	PCPC CFTPP								5.2	9.1	1.3		

<u>PSI vs. PSFI</u>

Fifty-five (55) generating plants that were pivotal suppliers were able to set the market price at the same time during the year. Of these, 33 are from Luzon while the remaining 22 are from Visayas. Large generating plants Ilijan NGPP and Sual CFTPP, both of which are associated with the SMC group, topped the list by becoming pivotal and price-setter at the same time at about 7.7 percent and 6.8 percent of the time respectively, followed by FGC's Sta. Rita NGPP at 3.6 percent, VEC's Bauang DPP at 2.4 percent, AP group's Navotas DPP at 2 percent and FGC's San Lorenzo NGPP at about 1.9 percent. PSALM's Kalayaan PSPP and TAOEDC's Subic DPP came next, setting the price and becoming pivotal at the same time at 1 percent of the time during the year.

On the other hand, oil-based plant PB 102 DPP under TAOEDC was on the top spot among the Visayas plants at about 2 percent, followed by GBPC's PEDC CFTPP at 1.8 percent, EAUC DPP of the AP group at 1.7 percent, and AP's CPPC DPP and GBPC's TPC (Carmen) DPP at 1.4 percent.

Overall, 19 oil-based plants dominated the list of pivotal suppliers which were price-setters at the same time, followed by 13 coal plants, hydro and geothermal with 9 each, and 4 natural gas plants. Note the inclusion of the Luzon biomass plant Isabela Bioethanol in the list of price-setters and pivotal suppliers from January to April, consistent with the change in its WESM membership classification from being a scheduled[33] to a priority dispatch[34] generating unit effective 28 April.

Figure 43. PSI vs. PSFI – Luzon Plants

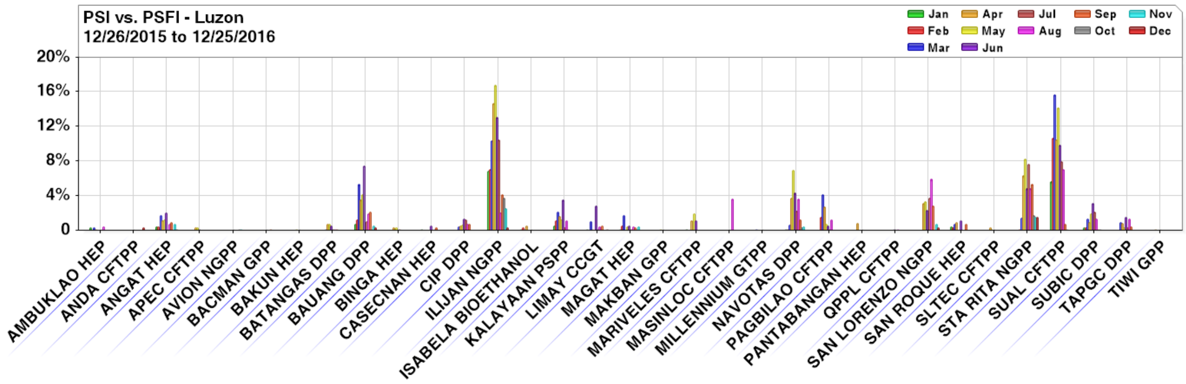


Table 51. PSI vs. PSFI – Luzon Plants

Major Participant Group	Luzon Generating Plant	PSI vs. PSFI (%) by Billing Month - 2016											
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
SMC	ILIJAN NGPP	6.9	7.0	10.3	14.7	16.8	13.0	10.4	2.0	4.2	3.8	2.6	0.3
SMC	SUAL CFTPP	5.6	10.6	15.7	10.5	14.2	9.8	7.9	7.0	0.7	0.1		
FGC	STA RITA NGPP		0.1	1.4	6.3	8.2	4.8	7.6	4.8	5.4	1.7	1.5	1.5
VEC	BAUANG DPP	0.7	1.2	5.3	3.5	4.2	7.4	1.0	1.9	2.2	0.1	0.5	0.3
AP	NAVOTAS DPP	0.1	0.1	0.6	3.8	6.9	4.3	2.2	3.6	1.2	0.3	0.4	
FGC	SAN LORENZO NGPP				3.1	3.3	2.3	3.8	5.9	2.8		0.7	0.3
PSALM	KALAYAAN PSPP	0.5	1.1	2.2	1.6	1.3	3.5	0.3	1.1	0.1			
TAOEDC	SUBIC DPP	0.3	0.3	1.3	0.9	1.9	3.1	2.1	1.3	0.1	0.1		
AP	PAGBILAO CFTPP		1.5	4.2	2.7	0.7	0.5	0.1	1.2				
SMC	ANGAT HEP	0.4	0.4	1.7	1.1	1.3	2.0		0.7	0.9		0.7	0.1
TAOEDC	CIP DPP			0.4	0.5	0.6	1.3	1.3	0.7	0.7			
TAOEDC	TAPGC DPP			0.9	0.8	0.3	1.5	0.3	1.3	0.4			
MEI	LIMAY CCGT	0.1		1.0	0.1		2.8	0.1	0.4	0.5			0.1
AP	MAGAT HEP	0.1	0.5	1.7		0.4	0.5	0.1	0.4	0.3	0.1	0.4	
GMCP	MARIVELES CFTPP	0.1			1.1	1.9	1.1						
SMC	SAN ROQUE HEP	0.4	0.3	0.7	0.9		1.1			0.7			
MPPC	MASINLOC CFTPP								3.6				
Other IPPs	BATANGAS DPP			0.1	0.7	0.7	0.5	0.1	0.1	0.1			
AP	AMBUKLAO HEP	0.3		0.3	0.1				0.4				
PSALM	CASECNAN HEP	0.1					0.5		0.1	0.3			
GFII	ISABELA BIOETHANOL	0.1	0.3	0.1	0.5								
FGC	PANTABANGAN HEP				0.8								
APEC	APEC CFTPP				0.3	0.3	0.1						
AP	BINGA HEP				0.3	0.3		0.1					
TAOEDC	SLTEC CFTPP				0.3	0.1							
APC	ANDA CFTPP												0.3
FGC	AVION NGPP										0.1	0.1	
QPPL	QPPL CFTPP						0.1		0.1				
FGC	BACMAN GPP									0.1			
VEC	BAKUN HEP					0.1							
AP	MAKBAN GPP					0.1							
MEI	MILLENNIUM GTPP			0.1									
AP	TIWI GPP				0.1								

[33] Scheduled Generation Company is defined in the WESM Rules as that which is required to play an active role in the spot market by submitting generation offers, and being subject to central dispatch.
[34] Priority dispatch is defined in the WESM Rules as the preference to biomass plants under the Feed-In Tariff System in the dispatch schedule pursuant to Section 7 of the Renewable Energy Act.

Figure 44. PSI vs. PSFI – Visayas Plants

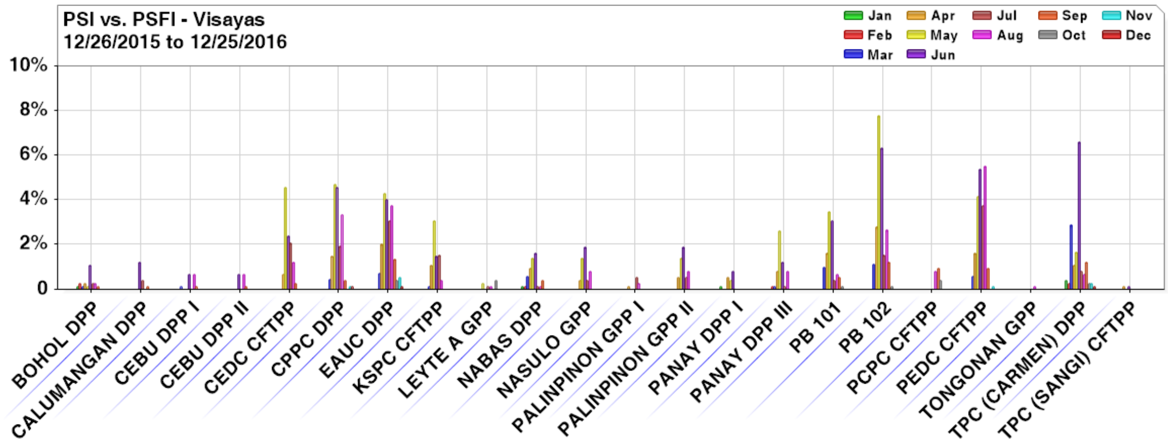


Table 52. PSI vs. PSFI – Visayas Plants

Major Participant Group	Visayas Generating Plant	PSI vs. PSFI (%) by Billing Month - 2016											
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
TAOEDC	PB 102			1.1	2.8	7.8	6.3	1.5	2.7	1.2	0.1		
GBPC	PEDC CFTPP			0.6	1.6	4.2	5.4	3.8	5.5	0.9		0.1	
AP	EAUC DPP			0.7	2.0	4.3	4.0	3.1	3.8	1.3	0.4	0.5	0.1
AP	CPPC DPP			0.4	1.5	4.7	4.6	1.9	3.4	0.4		0.1	0.1
GBPC	TPC (CARMEN) DPP	0.4	0.3	2.9	1.1	1.7	6.6	0.8	0.7	1.2	0.3	0.3	0.1
GBPC	CEDC CFTPP				0.7	4.6	2.4	2.1	1.2	0.3			
TAOEDC	PB 101			1.0	1.6	3.5	3.1	0.4	0.7	0.5	0.1		
SPC	KSPC CFTPP			0.1	1.1	3.1	1.5	1.5	0.4				
SPC	PANAY DPP III		0.1	0.1	0.8	2.6	1.2	0.1	0.8				
GBPC	NABAS DPP	0.1	0.1	0.6	0.9	1.4	1.6	0.1	0.1	0.4			
FGC	PALINPINON GPP II				0.5	1.4	1.9	0.6	0.8				
FGC	NASULO GPP				0.4	1.4	1.9	0.4	0.8				
SPC	BOHOL DPP	0.1	0.3	0.1	0.3	0.1	1.1	0.3	0.3	0.1			
PCPC	PCPC CFTPP								0.8	0.9	0.4		
SPC	PANAY DPP I	0.1			0.5	0.4	0.8						
Other IPPs	CALUMANGAN DPP						1.2	0.4		0.1			
SPC	CEBU DPP I			0.1			0.7		0.7	0.1			
SPC	CEBU DPP II						0.7		0.7	0.1			
PSALM	LEYTE A GPP					0.3		0.1	0.1		0.4		
FGC	PALINPINON GPP I				0.1			0.6	0.3				
GBPC	TPC (SANGI) CFTPP				0.1		0.1						
GBPC	TONGONAN GPP								0.1				

XI. MARKET RESIDUAL SUPPLY[35]

As shown in the Figure below, the hourly market RSI was more than or equal to100 percent in about 61.5 percent of the time during the year 2016, providing an indication of effective supply[36] sufficiency in meeting demand requirements during the year. Notwithstanding, the remaining 38.5 percent had market RSI below 100 percent, signalling the presence of pivotal suppliers during those intervals.

The June and August billing months, which had the highest frequency of market RSI below 100 percent during the year, were also the same months which exhibited the highest number of pivotal suppliers. Market RSI levels were noted to be lowest on 30 July at 1800H and on 05 August at 1900H and 2100H when effective supply levels were remarkably low due to high outage capacity. Conversely, November and December were marked with the highest occurrence of market RSI above 100 percent, indicating better supply and demand condition during these months.

Market RSI levels this year generally improved when compared with the previous year, indicated by the occurrence of market RSI levels below 100 percent which were observed more frequently in 2015 in about 40.2 percent of the time.

Figure 45. Market RSI Based on Effective Supply – System

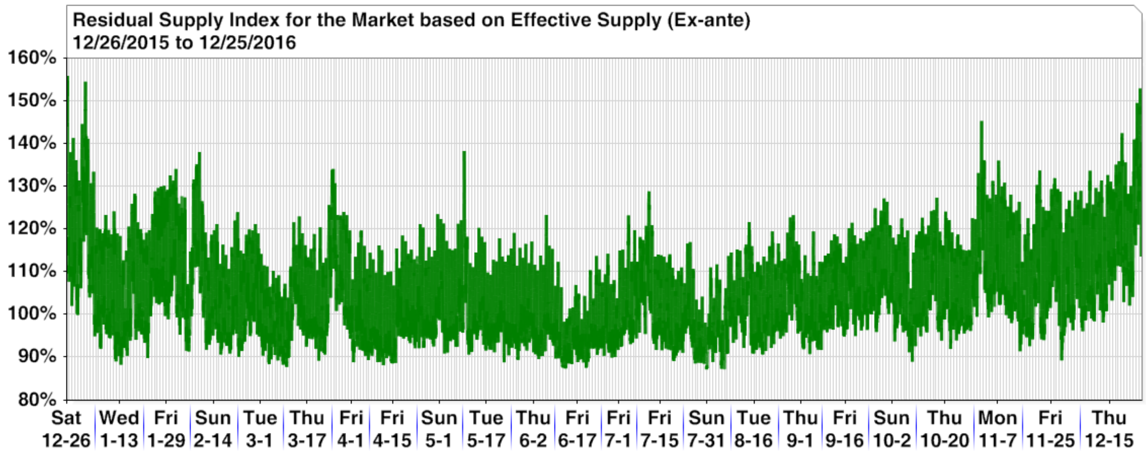


Table 53. Market RSI Summary – System, 2016

	Market RSI (%) Distribution by Billing Month - 2016, System												
	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Oct	Nov	Dec	Avg
Less than 100%	24.6	27.6	48.0	52.6	53.7	72.3	48.2	56.3	26.5	25.7	18.2	7.9	38.5
More than or equal to 100%	75.4	72.4	52.0	47.4	46.3	27.7	51.8	43.7	73.5	74.3	81.8	92.1	61.5

Table 54. Market RSI Summary – System, 2015

	Market RSI (%) Distribution by Billing Month - 2015, System												
	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Oct	Nov	Dec	Avg
Less than 100%	28.7	49.9	47.2	40.2	53.1	68.8	48.1	29.7	14.9	28.8	41.5	32.0	40.2
More than or equal to 100%	71.3	50.1	52.8	59.8	46.9	31.2	51.9	70.3	85.1	71.3	58.5	68.0	59.8

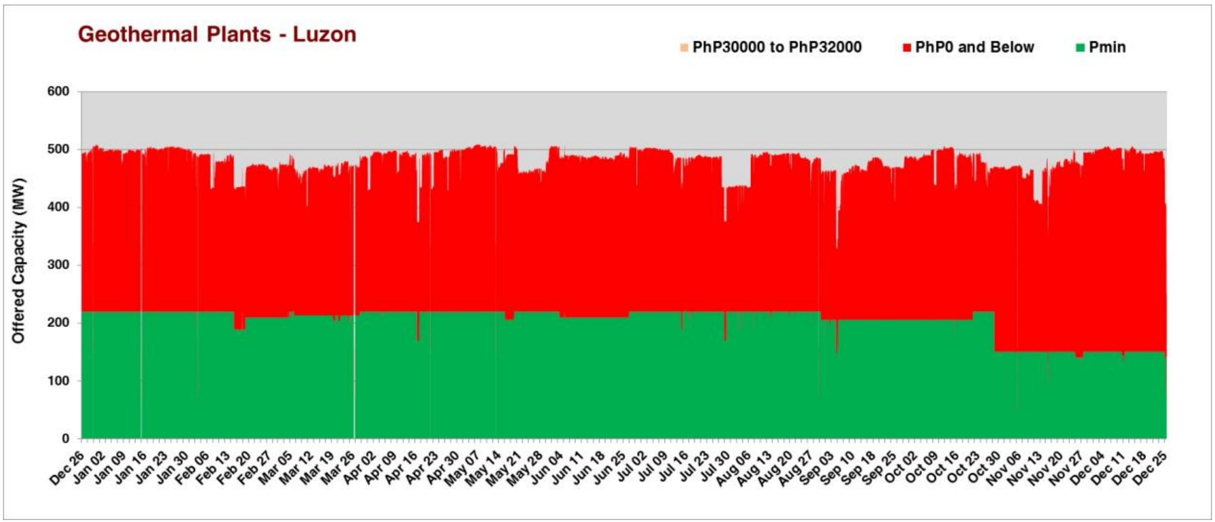
[35] The Residual Supply Index (RSI) measures the ratio of effective supply without a generator to the total supply required to meet the demand. The RSI of a generator measures the percentage of the remaining effective supply in the market after subtracting the effective supply of that generator. The 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.

[36] The system effective supply is equal to the offered capacity of all scheduled generator resources, nominated loading level of non-scheduled generating units and projected output of preferential dispatch generating units adjusted for any security limit and ramp rates. Scheduled output of plants on testing and commissioning, through the imposition of security limit by SO, are accounted for in the effected supply. Likewise included is the scheduled output of Malaya plant when it is called to run as MRU.

XII. GENERATOR OFFER PATTERN[37]

Luzon geothermal plants had the lowest offer prices among all the plant types throughout the 12-month period, with all of its capacity offers priced at PhP0/MWh and below. Consequently, almost all of its submitted offers were scheduled for dispatch during the year.

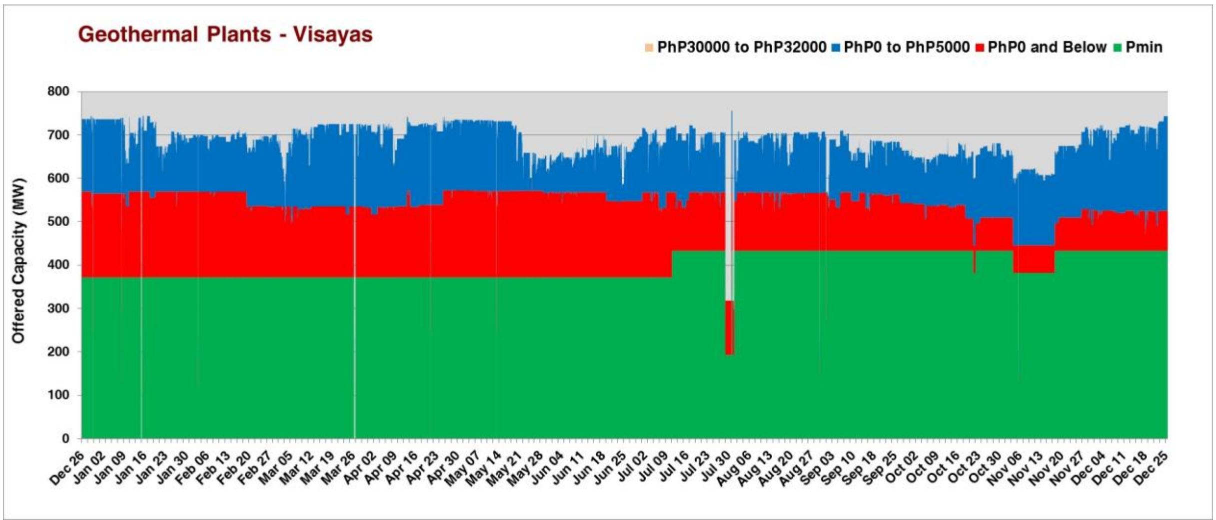
Figure 46. Geothermal Plants Offer Pattern – Luzon



Visayas geothermal plants submitted 80.2 percent of its offers at prices PhP0/MWh and below while 20.9 percent were priced above PhP0/MWh to PhP5,000/MWh. Thus, almost all its capacity offers had been scheduled for dispatch throughout the year. It is also noted that RTD schedules of Visayas geothermal plants were higher than its capacity offers on several occasions due to the imposition of over-riding constraints on various plants.

Noticeable drop in the capacity offer of the geothermal plants in the region were observed from 30 July to 03 August, influenced by the maintenance outages of Malitbog GPP 1 from 30 July to 03 August, and Malitbog GPP 3 from 30 September to 02 August.

Figure 47. Geothermal Plants Offer Pattern – Visayas



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

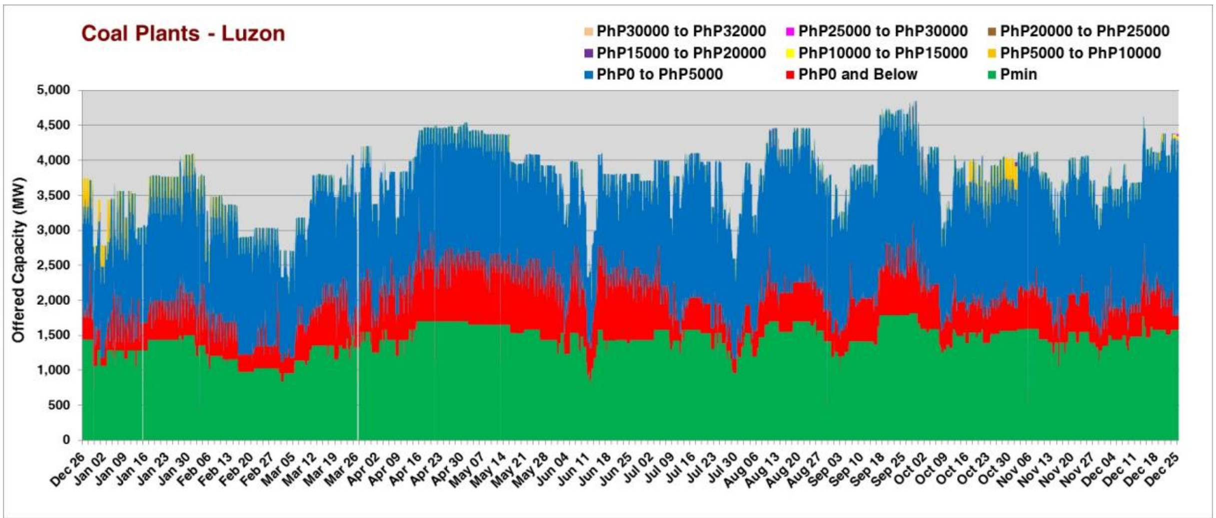
Lower capacity offers were visibly observed among the Luzon coal plants during the first quarter of the year, when several major coal plants in the region were on outage. Nevertheless, offered capacity started to increase in April, as plants on outage in the first quarter resumed operations. Capacity offers which were made available in the market were then sustained within an average of above 3,600 MW until yearend, but was notably highest in May, with capacity offers averaging at 4,296 MW.

In terms of offer prices, Luzon coal plants priced 44.9 percent of its capacity offers at above PhP0/MWh to PhP5,000/MWh, while 53.5 percent were priced at PhP0/MWh and below. Another 1.5 percent were offer prices ranging above PhP5,000/MWh to PhP15,000/MWh and a minimal 0.2 percent at above PhP30,000/MWh. The offer pattern of Luzon coal plants changed slightly in January, February, October and November, with the submission of more capacity at prices above PhP5,000/MWh to PhP10,000/MWh.

Higher RTD schedules vis-a-vis offered capacity were noted for some trading intervals in May and June, brought about by the imposition of over-riding constraints on Anda CFTPP and SLPGC CFTPP units 1 and 2.

About 93.4 percent of the capacity offers of Luzon coal plants were scheduled for dispatch during the billing year.

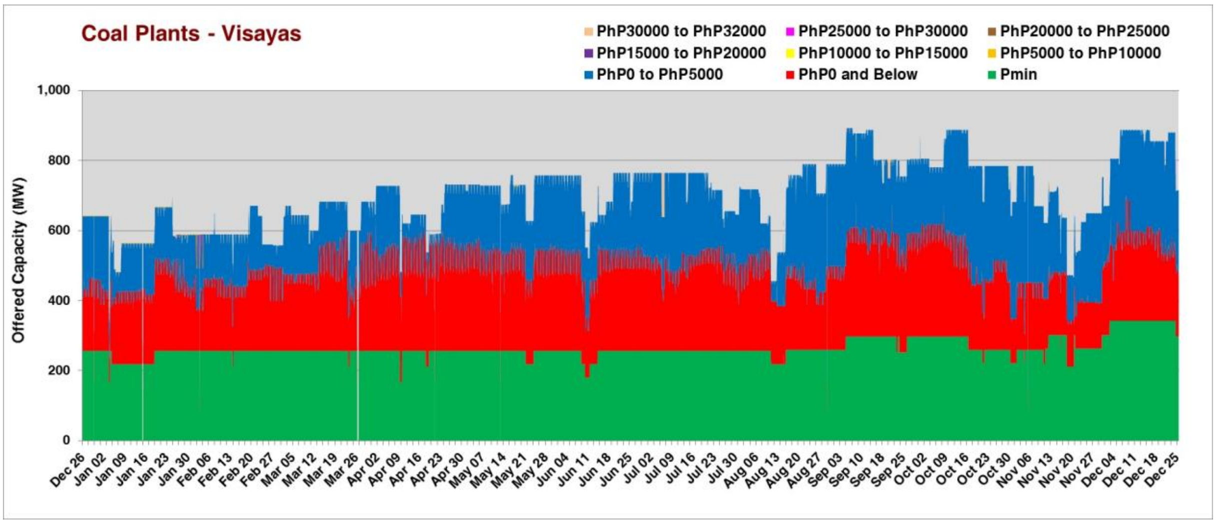
Figure 48. Coal Plants Offer Pattern – Luzon



Visayas coal plants recorded relatively lower offer prices across the billing year, with about 70.3 percent of its offers priced at PhP0/MWh and below. The remaining 29.3 percent were offer prices comprised of above PhP0/MWh to PhP5,000/MWh while a minimal 0.2 percent were offer prices above PhP30,000/MWh. Consequently, about 89 percent of the capacity offers of Visayas coal plants were scheduled for dispatch during the year.

Low offered capacity was observed among Visayas coal plants during the first quarter, while dips in the level of capacity offers was observed in August and November. These were all attributable to the high outage capacity of coal plants in the region during the affected period.

Figure 49. Coal Plants Offer Pattern – Visayas

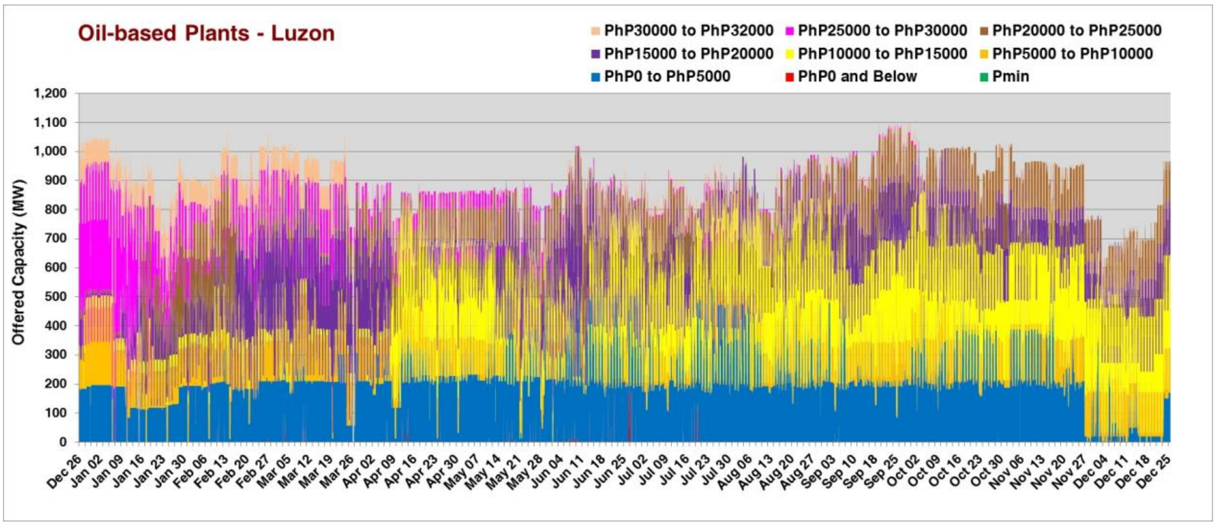


Luzon oil-based plants submitted the highest offer prices among all plant types, with 38.3 percent of its offers priced above PhP10,000/MWh to PhP20,000/MWh. An equally high 36.1 percent were prices attributed to PhP10,000/MWh and below, 11.7 percent of which were above PhP5,000/MWh to PhP10,000/MWh while 24.2 percent comprised of PhP5,000/MWh and below. 17.2 percent of the remaining offers were priced even higher, at above PhP20,000/MWh to PhP30,000/MWh, while 8.5 percent were priced at PhP30,000/MWh.

It was observed that more capacity was offered at the higher price range of above PhP20,000/MWh during the first quarter of the year, when compared with the rest of the billing months. Drop in the level of offered capacity was also noted in December attributed to the high outage capacity among the oil-based plants in the region.

Meanwhile, only an average of 13.7 percent of the total capacity offers of Luzon oil-based plants were scheduled for dispatch during the year. Lower RTD schedules were noted in October, November and December at 5.6 percent, 3.3 percent and 1.3 percent, while the April to August billing months recorded the highest RTD schedules at 23.2 percent, 22.5 percent, 26.1 percent, 19.9 percent and 25.6 percent, respectively.

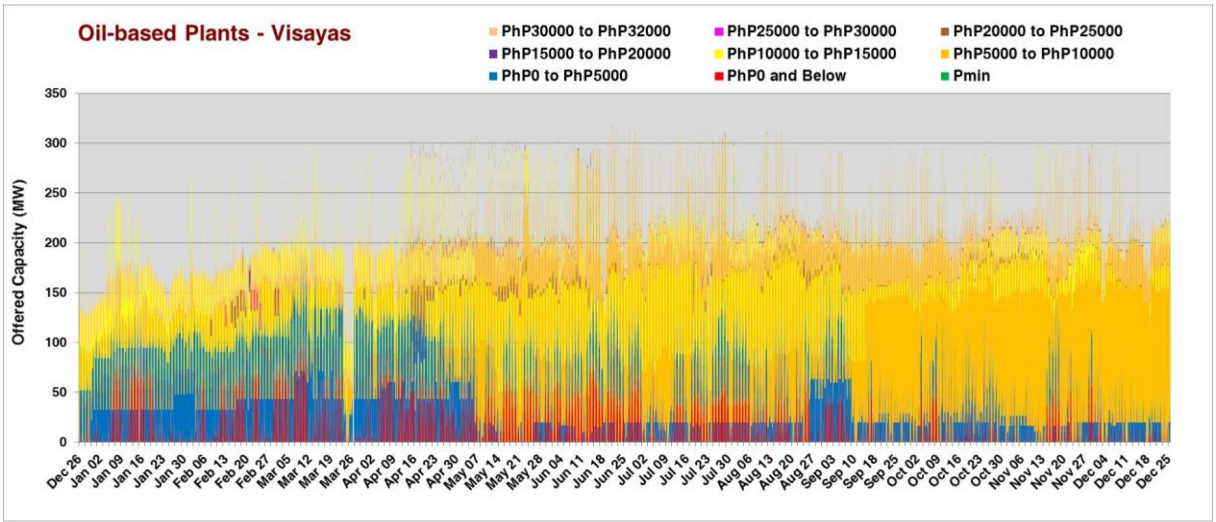
Figure 50. Oil-based Plants Offer Pattern – Luzon



Visayas oil-based plants likewise offered its capacity at high prices. The bulk of its capacity were offers submitted at prices above PhP5,000/MWh to PhP10,000/MWh while 14.9 percent were capacity offers priced at above PhP10,000/MWh to PhP20,000/MWh. Meanwhile, 1.1 percent were offers submitted at prices above PhP20,000/MWh to PhP30,000/MWh and 7.1 percent were priced above PhP30,000/MWh. The remaining 28.9 percent were priced at PhP5,000/MWh and below.

Considering the high offer prices submitted by Visayas oil-based plants, only about 15.5 percent of its capacity offers were scheduled for dispatch during the year. Nevertheless, Visayas oil-based plants recorded higher RTD schedules during the March, April, June and August billing months at 24.9 percent, 23 percent, 28.6 percent and 21.3 percent.

Figure 51. Oil-based Plants Offer Pattern – Visayas



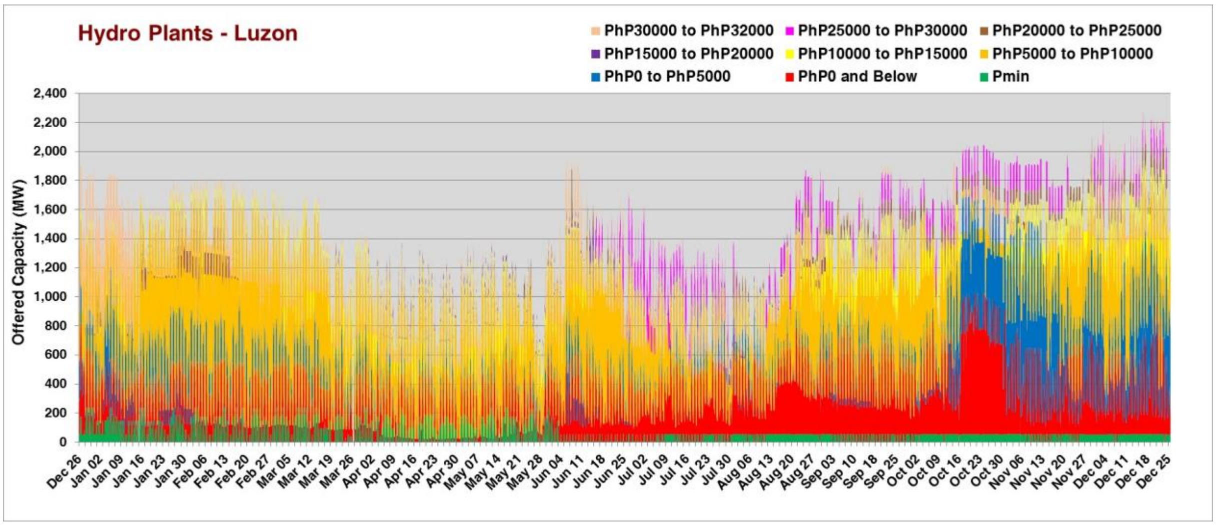
Capacity offers from Luzon hydro plants were notably lower during the summer months of April and May, averaging at only 897 MW and 908 MW. Nevertheless, this increased during the last quarter of the year, averaging at a high of 1,670 MW of offered capacity in December. Capacity offers of Luzon hydro plants declined noticeably in August and September, averaging at only 932 MW and 961 MW, respectively. This decline was in part driven by the planned outages of Kalayaan PSSP 1 and 2 during these months.

About 28 percent of the offers of hydro plants were priced at PhP0/MWh and below, while 14.8 percent were capacity offers above PhP0/MWh to PhP5,000/MWh, and 43.7 percent were offer prices above PhP5,000/MWh to PhP10,000/MWh. Meanwhile, another 5.5 percent were offers at above PhP10,000/MWh to PhP20,000/MWh and another 4.1 percent were capacity offers attributed at above PhP20,000/MWh to PhP30,000/MWh. Lastly, the remaining 3.9 percent were capacity offers above PhP30,000/MWh.

Hydro plants offered more capacities at prices above PhP30,000/MWh from January to April, as well as in June. Meanwhile, offer prices above PhP20,000/MWh to PhP30,000/MWh were more frequently observed from August to December.

An average of about 39 percent of the capacity offers of hydro plants were scheduled for dispatch, with its monthly RTD schedules closely averaging at above 30 percent of its total offered capacity across the year. However, higher RTD schedules were observed in August at 54.7 percent, and October, at 48.5 percent.

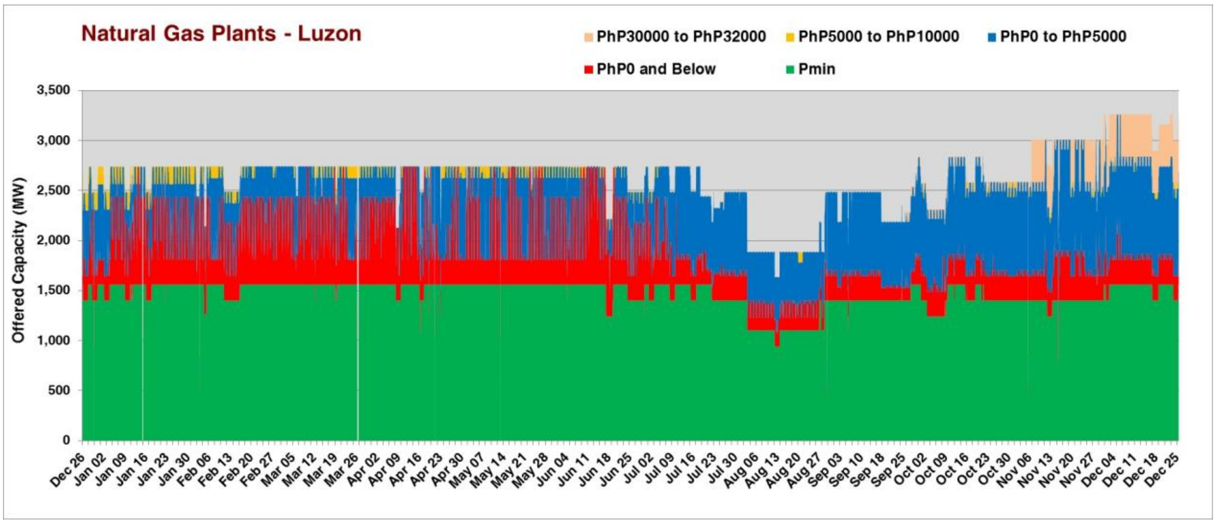
Figure 52. Hydro Plants Offer Pattern – Luzon



Offer prices of natural gas plants were relatively lower when compared with other plant types, with 73.3 percent of its capacity offers priced at PhP0/MWh and below. The remaining 23.7 percent were offers priced above PhP0/MWh and PhP5,000/MWh while another 1 percent was attributed to prices above PhP5,000/MWh to PhP10,000/MWh. Another 2 percent were capacity offers above PhP30,000/MWh, majority of which were notably submitted during the August, October, November and December billing months.

Meanwhile, dip in the capacity offers submitted by natural gas plants was observed in August, during which high outage capacity was noted mainly due to the planned outages of Ilijan NGPP Block B and Sta. Rita NGPP 2. Capacity offers averaged at only 2,042 MW during the period, a decline from the monthly average of 2,632 MW during the year. Nevertheless, higher capacity offers were noted in November and December, averaging at a high of 2,824 MW and 3,143 MW, with more plants becoming available during these months.

Figure 53. Natural Gas Plants Offer Pattern – Luzon



XIII. GENERATOR CAPACITY FACTOR[38]

As illustrated in the Figures below, the monthly capacity factor of generation facilities show that the same varies depending on the energy resource type.

Coal plants obtained relatively higher capacity factors for the billing year, posting an average of about 62.9 percent utilization in terms of registered capacity, 74.1 percent in terms of registered less outage capacity and 85.3 percent in terms of offered capacity. The capacity factor of coal plants was lower during the first quarter, following the high outage capacity among coal plants during the period. It is also observed that coal plants in Luzon were utilized more during the year than the coal plants in the Visayas.

The capacity factors recorded by natural gas plants were generally lower than those obtained by coal plants during the year, posting its utilization at an average of 69.1 percent based on registered capacity, 73.8 percent based on registered less outage capacity and 84.2 percent based on offered capacity. Nevertheless, these were still relatively higher when compared with other plant types. Utilization of natural has plants in terms of registered capacity was noticeably lower during from August to December, considering the high outage capacity and high capacity gap of natural gas plants during those months.

Geothermal plants incurred an average of 61.4 percent utilization based on registered capacity and 74.8 percent based on registered less outage capacity, indicating that outage level among geothermal plants remain high this year. Notwithstanding, the utilization of geothermal plants based on offered capacity averaged at a high of 93.4 percent, the highest among all plant types. This demonstrates that capacity offers submitted by geothermal plants were generally dispatched and utilized during the year. Regional capacity factors of geothermal plants indicate better utilization of the Visayas geothermal plants than those in Luzon due to the high outage capacity of geothermal plants in the Luzon region.

Hydro plants posted low utilization levels across the year based on registered capacity and registered less outage capacity, averaging at 22.7 percent and 25.1 percent, respectively. Its capacity factors were even lower during the summer months particularly from March to May and July. This pattern of low utilization is consistent with the limited offer submission as reflected in the high level of capacity gap among hydro plants. Nevertheless, hydro plants posted an average of 44.6 percent capacity factor based on offered capacity. Its highest offered capacity utilization was recorded in August at an average of 61.2 percent, suggesting that its offers were generally scheduled and dispatched in the market during this month.

Oil-based plants recorded the lowest utilization among all plant types, plunging to 9.4 percent, 10.7 percent, and 19.8 percent, respectively, based on registered capacity, registered less outage capacity and offered capacity. Nonetheless, higher levels of capacity factors based on offered capacity is posted from March to August, with the August billing month posting the highest utilization at 38.6 percent. This trend demonstrates the more frequent dispatch and higher utilization of oil-based plants particularly in August, following the tight demand and supply condition during the month.

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. While the utilization of solar plants closely ranged from 15.9 percent to 20.9 percent throughout the year, wind plants incurred lower utilization during the summer months and biomass plants posted lower utilization during the second and third quarters.

[38] 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.

Figure 54. Capacity Factor – System

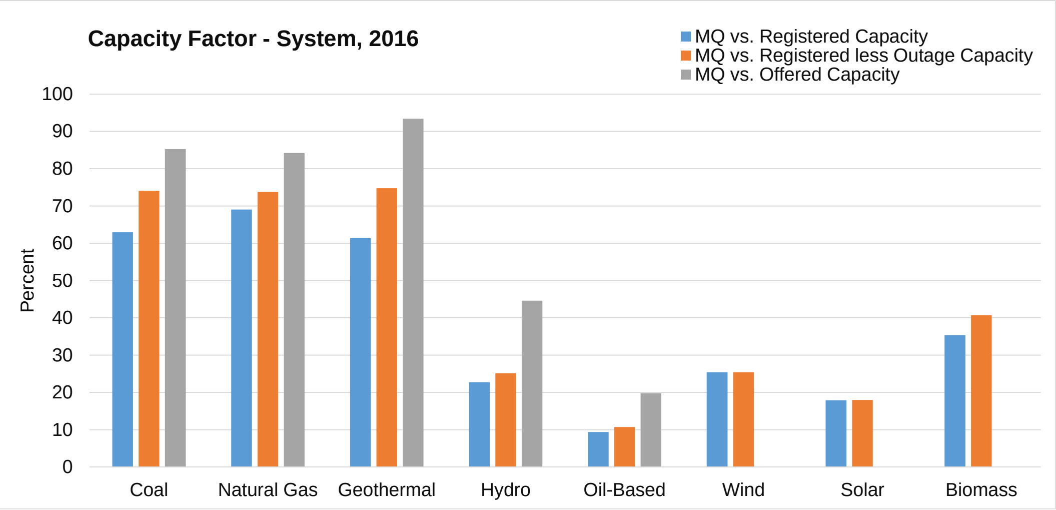


Figure 55. Capacity Factor – Luzon

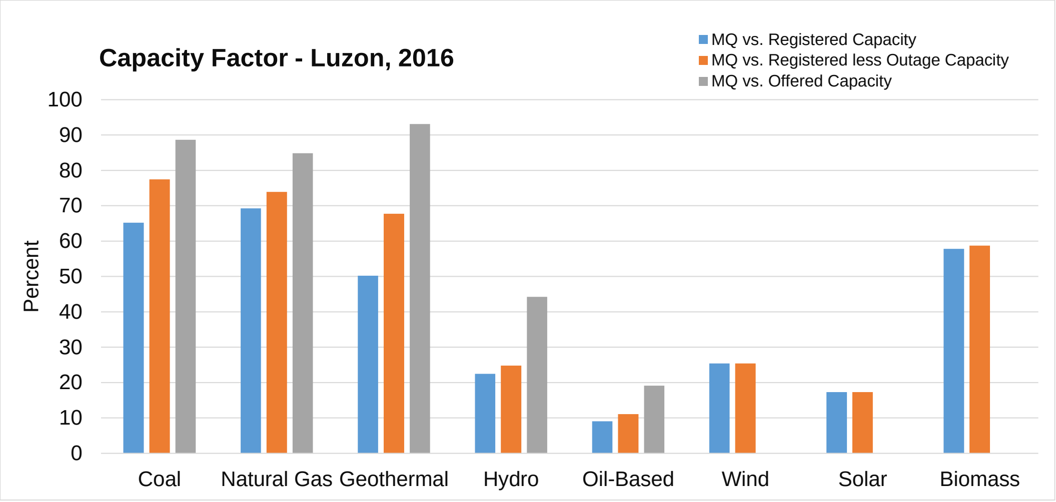


Figure 56. Capacity Factor – Visayas

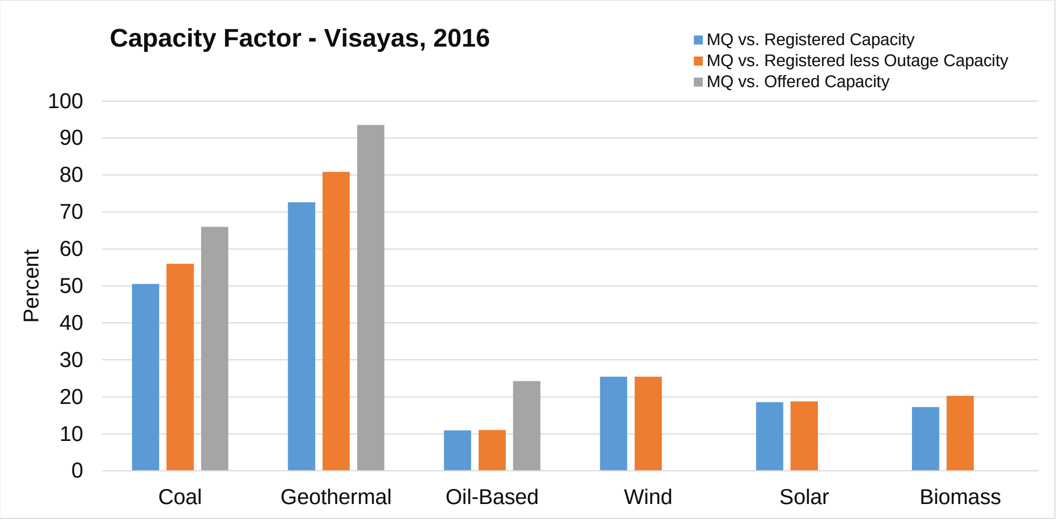


Table 55. Capacity Factor by Plant Type – System

Plant Type	Capacity Factor (%) by Billing Month, System - 2016												
	MQ vs. Registered Capacity												
	Jan	Feb	Mar	Apr	May	June	Jul	Aug	Sept	Oct	Nov	Dec	Avg
Coal	50.4	53.6	56.6	67.6	75.6	67.1	66.5	67.7	67.1	64.2	61.4	57.2	62.9
Natural Gas	74.4	77.9	74.6	71.0	70.8	76.2	70.7	60.3	65.7	65.3	62.5	61.6	69.1
Geothermal	63.8	62.7	62.4	63.1	63.7	59.8	61.6	59.4	60.2	59.2	57.8	62.8	61.4
Hydro	22.9	20.6	18.8	13.6	13.2	21.2	19.4	23.7	26.0	32.7	30.1	30.4	22.7
Oil-Based	4.6	5.8	10.8	13.6	16.6	16.5	13.1	18.6	5.1	4.6	2.5	1.2	9.4
Wind	33.8	45.2	31.0	18.0	10.8	7.9	8.3	19.7	19.7	16.5	40.9	52.7	25.4
Solar	18.4	16.7	18.0	20.3	20.9	18.9	17.7	16.6	18.5	16.8	15.9	16.1	17.9
Biomass	40.9	42.3	42.1	40.2	30.2	26.8	28.5	30.4	28.4	37.3	39.5	38.0	35.4

Plant Type	MQ vs. Registered less Outage Capacity												
	Jan	Feb	Mar	Apr	May	June	Jul	Aug	Sept	Oct	Nov	Dec	Avg
Coal	66.3	69.3	73.7	74.8	78.3	78.6	75.3	77.4	77.0	74.5	73.4	68.2	74.1
Natural Gas	77.7	81.0	76.0	72.8	71.7	78.5	74.5	78.2	74.6	70.1	68.2	63.8	73.8
Geothermal	77.1	82.8	77.7	74.7	74.4	71.1	72.0	75.3	77.2	73.0	71.3	71.7	74.8
Hydro	23.9	22.7	20.0	16.6	14.8	23.4	21.0	27.3	30.2	36.1	33.5	31.5	25.1
Oil-Based	5.3	6.1	12.2	16.2	19.8	20.0	15.9	22.3	5.6	4.7	2.7	1.5	10.7
Wind	33.8	45.2	31.0	18.1	10.8	7.9	8.3	19.7	19.7	16.5	40.9	52.7	25.4
Solar	18.5	16.7	18.1	20.4	21.0	18.9	18.0	16.6	18.5	17.0	16.0	16.1	18.0
Biomass	52.2	45.5	45.8	43.8	39.2	35.0	36.8	38.9	33.4	37.9	40.7	39.7	40.7

Plant Type	MQ vs. Offered Capacity												
	Jan	Feb	Mar	Apr	May	June	Jul	Aug	Sept	Oct	Nov	Dec	Avg
Coal	75.0	79.9	85.6	90.0	91.4	93.1	87.6	89.5	85.6	82.4	83.9	77.1	85.3
Natural Gas	81.1	83.6	87.8	87.9	85.0	92.9	90.2	96.8	92.8	83.1	72.9	64.5	84.2
Geothermal	94.0	95.1	94.5	95.0	93.3	93.0	92.1	93.2	93.4	91.8	92.7	92.5	93.4
Hydro	38.9	34.6	37.8	38.3	36.1	45.1	51.6	61.2	46.9	53.6	47.2	45.2	44.6
Oil-Based	10.2	12.6	22.1	30.8	35.6	34.8	28.2	38.6	9.9	8.8	4.9	3.0	19.8

Table 56. Capacity Factor by Plant Type – Luzon

Plant Type	Capacity Factor (%) by Billing Month, Luzon - 2016												
	MQ vs. Registered Capacity												
	Jan	Feb	Mar	Apr	May	June	Jul	Aug	Sept	Oct	Nov	Dec	Avg
Coal	50.5	53.8	57.0	71.1	79.2	69.5	68.6	71.2	71.2	67.5	64.4	58.5	65.2
Natural Gas	74.4	77.9	74.6	71.0	70.8	76.2	70.7	60.3	65.7	65.3	62.5	61.6	69.2
Geothermal	51.1	50.0	48.7	50.2	51.4	51.1	51.4	49.2	48.9	50.9	48.4	51.3	50.2
Hydro	22.9	20.5	18.7	13.6	13.1	21.0	19.1	23.4	25.6	32.2	29.7	30.0	22.5
Oil-Based	3.4	5.1	9.9	13.5	17.0	16.1	13.4	19.2	4.6	3.8	1.9	0.8	9.1
Wind	32.1	43.1	30.6	15.2	8.8	8.5	8.4	17.0	21.6	16.6	43.9	58.6	25.4
Solar	15.2	14.8	16.4	20.3	21.1	19.1	18.1	15.0	17.6	15.6	17.3	16.8	17.3
Biomass	63.5	51.4	57.4	59.8	59.9	59.1	63.8	67.3	57.0	56.3	52.2	46.2	57.8

Plant Type	MQ vs. Registered less Outage Capacity												
	Jan	Feb	Mar	Apr	May	June	Jul	Aug	Sept	Oct	Nov	Dec	Avg
Coal	67.2	70.0	75.5	78.7	82.5	83.2	79.5	81.9	82.8	79.9	77.0	71.3	77.5
Natural Gas	77.7	81.0	76.0	72.8	71.7	78.5	74.5	78.2	74.6	70.1	68.2	63.8	73.9
Geothermal	70.5	75.3	65.8	64.5	65.6	65.9	67.2	69.6	72.8	68.4	64.7	62.7	67.7
Hydro	23.8	22.5	19.9	16.5	14.8	23.2	20.6	26.9	29.7	35.6	33.1	31.1	24.8
Oil-Based	4.0	5.4	11.6	16.8	21.2	20.5	17.1	24.1	5.1	4.0	2.1	1.0	11.1
Wind	32.1	43.1	30.6	15.3	8.8	8.5	8.4	17.0	21.6	16.6	43.9	58.6	25.4
Solar	15.2	14.8	16.4	20.3	21.1	19.1	18.1	15.0	17.6	15.6	17.3	16.8	17.3
Biomass	63.6	54.2	58.6	60.9	59.9	60.3	63.8	67.3	57.0	56.3	52.9	49.8	58.7

Plant Type	MQ vs. Offered Capacity												
	Jan	Feb	Mar	Apr	May	June	Jul	Aug	Sept	Oct	Nov	Dec	Avg
Coal	76.9	82.3	89.2	94.0	95.3	98.3	92.0	93.4	90.5	86.7	85.9	79.4	88.7
Natural Gas	81.1	83.6	87.8	87.9	85.0	92.9	90.2	96.8	92.8	83.1	72.9	64.5	84.9
Geothermal	92.0	93.4	92.6	94.1	93.2	93.6	93.0	92.9	93.5	93.2	93.3	92.6	93.1
Hydro	38.8	34.4	37.6	38.1	35.9	44.7	50.7	60.3	46.2	52.8	46.6	44.6	44.2
Oil-Based	7.1	10.7	20.0	30.4	36.7	33.9	29.2	40.0	8.6	7.2	3.8	2.0	19.1

Table 57. Capacity Factor by Plant Type – Visayas

Plant Type	Capacity Factor (%) by Billing Month, Visayas - 2016												
	MQ vs. Registered Capacity												
	Jan	Feb	Mar	Apr	May	June	Jul	Aug	Sept	Oct	Nov	Dec	Avg
Coal	50.2	51.9	54.0	47.3	54.3	53.2	54.5	48.8	47.1	47.8	46.7	50.8	50.5
Geothermal	76.6	75.5	76.2	76.1	76.1	68.7	71.9	69.8	71.6	67.5	67.2	74.5	72.6
Oil-Based	9.9	9.0	14.4	14.1	15.0	18.2	11.8	16.2	7.3	7.6	4.9	3.1	10.9
Wind	40.2	53.2	32.3	28.6	18.6	5.8	7.8	29.8	12.6	16.0	29.7	30.5	25.4
Solar	21.2	20.3	19.3	20.3	20.7	18.7	17.4	17.6	19.1	17.7	15.0	15.6	18.6
Biomass	25.3	35.2	30.1	24.9	6.9	1.5	0.7	0.8	2.9	20.1	27.9	30.7	17.2

Plant Type	MQ vs. Registered less Outage Capacity												
	Jan	Feb	Mar	Apr	May	June	Jul	Aug	Sept	Oct	Nov	Dec	Avg
Coal	60.9	64.8	63.3	52.2	54.9	55.3	54.7	53.9	50.7	51.1	55.8	54.3	56.0
Geothermal	82.3	88.8	87.9	83.5	81.8	75.6	76.0	80.0	80.6	76.9	77.0	79.7	80.8
Oil-Based	10.0	9.0	14.4	14.1	15.0	18.5	11.9	16.2	7.3	7.7	4.9	3.1	11.0
Wind	40.2	53.2	32.3	28.6	18.6	5.8	7.8	29.8	12.6	16.0	29.7	30.5	25.4
Solar	21.4	20.4	19.6	20.5	20.9	18.8	17.9	17.8	19.2	17.9	15.1	15.6	18.8
Biomass	39.8	38.4	34.5	28.7	11.7	2.4	1.2	1.3	4.1	20.7	29.3	31.0	20.3

Plant Type	MQ vs. Offered Capacity												
	Jan	Feb	Mar	Apr	May	June	Jul	Aug	Sept	Oct	Nov	Dec	Avg
Coal	64.5	66.5	66.5	65.9	68.3	66.7	65.1	67.2	61.3	61.7	72.1	65.8	66.0
Geothermal	95.4	96.2	95.8	95.7	93.4	92.6	91.4	93.4	93.3	90.8	92.2	92.4	93.6
Oil-Based	27.9	22.2	33.0	32.2	31.6	38.3	24.4	33.0	15.8	16.6	10.0	6.6	24.3

XIV. 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.

A. Frequency of active constraints (Ex-ante)

About 94 percent of the total constraints in the ex-ante at the load-side transformers (4,160 of the total 4,425 constraints), were attributable to the Luzon region and were essentially on account of the constraints at the Zapote transformer.

Similar with the previous year, high occurrence of constraints were consistently observed at the Zapote transformer mainly due to the violation of the contingency (N-1) requirement, though the same was a decrease at 3,335 from last year's total of 3,604.

The remaining 6 percent of the constraints were those at the Visayas, which totalled at 265. Of which, 151 were due to the constraints at the Sta. Barbara transformers, accounting for 3.4 percent of the total constraints at the load-side transformers this year.

On the other hand, base-case constraints at the generator transformers totalled at 205 this year, with those in Luzon accounting for 65.4 percent or 134 out of the 205 constraints observed at generator transformers during the year. Constraints at the Caliraya transformer were highest at 82, which is 40 percent of the total constraints system-wide. Meanwhile, the Bacman transformer recorded a total of 23 constraints that is 11.2 percent of the total constraints during the year.

The Visayas region accounted for the remaining 34.6 percent. Recorded constraints at the PEDC transformers were the most frequent at 28, which is 13.7 percent of the total recorded constraints system-wide.

Table 58. Frequency of Constraints at Load-Side Transformers (Ex-Ante)

Frequency of Constraints on Load-End Transformers (Ex-Ante) - 2016														
Region	**Equipment Name**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
Luzon	San Jose EHV Transformer											1		1
	San Manuel EHV Transformer			26										26
	Gamu Transformer									1				1
	Hermosa Transformer				9	63								72
	Kadampat Transformer		12											12
	La Trinidad Transformer		5	54										59
	Labrador Transformer											1		1
	San Esteban Transformer										2			2
	San Jose Transformer							2						2
	San Manuel Transformer				1	1								2
	Santiago Transformer							18				1		19
	Tuguegarao Transformer				1		1							2
	Dona Imelda (Araneta) Transformer									2		2		4
	Dolores Transformer				12	56	7	1	8					84
	Manila (Paco) Transformer						4			6				10
	Quezon (Balintawak) Transformer	2	4	16	56	114	46	27	30	51	50	47	33	476
	Zapote Transformer	131	152	200	315	403	393	297	302	278	313	316	235	3,335
	Daraga Transformer									1	14			15
	Dasmariñas Transformer	3		2									6	11
	Lumban Transformer										7	16		23
	Tayabas Transformer			3										3
Subtotal - Luzon		**136**	**173**	**301**	**394**	**637**	**451**	**345**	**340**	**339**	**386**	**384**	**274**	**4,160**
Visayas	Cebu Transformer	26		1							1			28
	Lapu-Lapu Transformer											28	18	46
	Mandaue Transformer							1				1		2
	Naga Transformer					1							1	2
	Quiot Transformer		7									22		29
	Talavera Transformer											3		3
	Mabinay Transformer			4										4
	Sta. Barbara Transformer	2		10	136								3	151
Subtotal - Visayas		**28**	**7**	**15**	**136**	**1**	**-**	**1**	**-**	**-**	**1**	**54**	**22**	**265**
Total - Luzon and Visayas		**164**	**180**	**316**	**530**	**638**	**451**	**346**	**340**	**339**	**387**	**438**	**296**	**4,425**

Table 59. Frequency of Constraints at Generator Transformers (Ex-Ante)

Frequency of Constraints on Generator Transformers (Ex-Ante) - 2016														
Region	**Equipment Name**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
Luzon	Angat Transformer		1	2	4					5	4		3	19
	Casecnan Transformer										3			3
	Avion Transformer					3	1	2						6
	Bacman Transformer	2	2		4	1		1	2	3	5	3		23
	Caliraya Transformer				10	23	25	11	2			7	4	82
	Kalayaan Transformer							1						1
Subtotal - Luzon		**2**	**3**	**2**	**18**	**27**	**26**	**15**	**4**	**8**	**12**	**10**	**7**	**134**
Visayas	Tongonan Transformer	2	1	1				2	1	2	1		5	15
	CEDC Transformer	1	1									1	2	5
	KSPC Transformer											7		7
	Palinpinon GPP 1 Transformer			1									1	2
	Palinpinon GPP 2 Transformer	1		1	1	1	10							14
	PEDC Transformer	1						1	23	2	1			28
Subtotal - Visayas		**5**	**2**	**3**	**1**	**1**	**10**	**3**	**24**	**4**	**2**	**8**	**8**	**71**
Total - Luzon and Visayas		**7**	**5**	**5**	**19**	**28**	**36**	**18**	**28**	**12**	**14**	**18**	**15**	**205**

Constraints on transmission lines totalled 1,268 for this year, about 72.6 percent of which were attributable to Visayas, while 27.4 percent, equivalent to 478 constraints, were noted on transmission lines in Luzon. Occurrences of constraints were highest at the Quiot-New Naga 138 kV Line which accounted for 68.2 percent (1,191 constraints) of the total constraints for the billing year.

Note that the August billing month recorded the highest number of constraints on transmission lines in the ex-ante across the year.

Also, constraints at the Visayas submarine cables totalled 1,839 this year, with the Negros-Panay submarine cable accounting for majority or 47.5 percent (874 constraints) of the total constraints, followed by the Cebu-Negros submarine cable with 40.1 percent or 738 constraints.

Table 60. Frequency of Constraints at Transmission Lines (Ex-Ante)

Frequency of Constraints on Transmission Lines (Ex-Ante) - 2016														
Region	Equipment Name	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Luzon	Balingueo-Kadampat 230kV Line						1							1
	Bauang-Balingueo 230kV Line								5			5		10
	Bauang-BPPC 230kV Line			31	44	25	65	34	29					228
	Bauang-La Trinidad 230kV Line				7		6							13
	Binga-San Manuel 230kV Line										7			7
	Bantay-San Esteban 115kV Line										1			1
	Botolan-Cawago 230kV Line				1									1
	BPPC-Kadampat 230kV Line			31	3	4								38
	Currimao-Bantay 115kV Line										2			2
	Laoag-Currimao 115kV Line										2			2
	Mexico-Hermosa 230kV Line						6							6
	San Manuel (New)-Pantabangan 230kV Line											47	7	54
	Pantabangan-Cabanatuan 230kV Line											12		12
	San Manuel (New)-San Manuel (Old) 230kV Tie-Line			20										20
	Quezon (Balintawak)-San Jose 230kV Line			2	1	9		21	14	5		1	1	54
	Quezon (Balintawak)-Dona Imelda (Araneta) 230kV Line			1										1
	Dolores-Malaya 230kV Line			1										1
	Amadeo-Calaca 230kV Line				10		1				1			12
	Malaya-Lumban 230kV Line			5										5
	Sta. Rita-Batangas 230kV Line			6										6
	Sta. Rosa-Calaca 230kV Line				2						1		1	4
Subtotal - Luzon		**-**	**-**	**97**	**68**	**38**	**79**	**55**	**48**	**5**	**14**	**65**	**9**	**478**
Visayas	New Naga-Cebu 138kV Line						9	10	8					27
	Quiot-New Naga 138kV Line		2	34	142	155	175	305	346	31			1	1,191
	Toledo-New Naga 138kV Line	4		2	4		23	1	5					39
	Amlan-Mabinay 138kV Line				2									2
	Bacolod-Cadiz 138kV Line										4	2	1	7
	Mabinay-Kabangkalan 138kV Line			2										2
Subtotal - Visayas		**4**	**2**	**38**	**148**	**155**	**207**	**316**	**359**	**31**	**4**	**2**	**2**	**1,268**
Total - Luzon and Visayas		**4**	**2**	**135**	**216**	**193**	**286**	**371**	**407**	**36**	**18**	**67**	**11**	**1,746**

Table 61. Frequency of Constraints at Submarine Cable (Ex-Ante)

Frequency of Constraints on Submarine Cables (Ex-Ante) - 2016														
Region	Equipment Name	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Visayas	Leyte-Bohol Submarine Cable											1		1
	Leyte-Cebu Submarine Cable	45	35	13	55	35	4	7	12	6	1	12	1	226
	Cebu-Negros Submarine Cable	1		1	6	7	1	2	55	104	117	230	214	738
	Negros-Panay Submarine Cable	12	11	36	77	155	96	79	211	94	87	12	4	874
Total		**58**	**46**	**50**	**138**	**197**	**101**	**88**	**278**	**204**	**205**	**255**	**219**	**1,839**

B. Frequency of active constraints (Ex-post)

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

A total of 496 constraints at the load-side transformers were observed during ex-post, 49.8 percent (247 constraints) of which were on account of the load-side transformers in Luzon, while 50.2 percent (249 constraints) were attributed to the Visayas.

Constraints at the Sta. Barbara transformer were most frequent, totalling at 149 (30 percent), followed by the Hermosa transformer with 121 constraints (24.4 percent).

Constraints at generator transformers were likewise observed during ex-post, which totalled at 126. 23.8 percent (44 constraints) were attributed to Luzon and the majority at 65.1 percent of the total (82 constraints) were attributed to Visayas.

Constraints were most frequently observed at the Bacman and PEDC transformers with 30 (23.8 percent) and 26 constraints (20.6 percent), respectively.

Table 62. Frequency of Constraints at Load-Side Substations (Ex-Post)

Frequency of Constraints on Load-End Transformers (Ex-Post) - 2016														
Region	**Equipment Name**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
Luzon	Gamu Transformer									1				1
	Hermosa Transformer				32	89								121
	La Trinidad Transformer		6	30										36
	San Esteban Transformer										2			2
	San Jose Transformer							2						2
	San Manuel Transformer				13	4								17
	Santiago Transformer					1		20				1		22
	Tuguegarao Transformer			1	6									7
	Dona Imelda (Araneta) Transformer					1						2		3
	Manila (Paco) Transformer					1								1
	Muntinlupa (Sucat) Transformer					1								1
	Zapote Transformer					1								1
	Daraga Transformer									1	10			11
	Lumban Transformer										6	16		22
Subtotal - Luzon		**0**	**6**	**31**	**51**	**98**	**0**	**22**	**0**	**2**	**18**	**19**	**0**	**247**
Visayas	Cebu Transformer	22		1							1			24
	Lapu-Lapu Transformer											28	17	45
	Naga Transformer												3	3
	Quiot Transformer		7									21		28
	Sta. Barbara Transformer	3		9	123							1	13	149
Subtotal - Visayas		**25**	**7**	**10**	**123**	**0**	**0**	**0**	**0**	**0**	**1**	**50**	**33**	**249**
Total - Luzon and Visayas		**25**	**13**	**41**	**174**	**98**	**0**	**22**	**0**	**2**	**19**	**69**	**33**	**496**

Table 63. Frequency of Constraints at Generator Transformers (Ex-Post)

Frequency of Constraints on Generator Transformers (Ex-Post) - 2016														
Region	**Equipment Name**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
Luzon	Angat Transformer			1							2			3
	Casecnan Transformer										3			3
	Bacman Transformer	2	1	1	6	3		2	2	3	6	4		30
	Caliraya Transformer						3	2					1	6
	Ilijan Transformer					1								1
	Tiwi Transformer				1									1
Subtotal - Luzon		**2**	**1**	**2**	**7**	**4**	**3**	**4**	**2**	**3**	**11**	**4**	**1**	**44**
Visayas	Tongonan Transformer	2	2	2		1		3	4	4	2		3	23
	CEDC Transformer	3	2						1			1	4	11
	KSPC Transformer											7		7
	Palinpinon GPP 1 Transformer										1		1	2
	Palinpinon GPP 2 Transformer			2			11							13
	PEDC Transformer	2							22	1	1			26
Subtotal - Visayas		**7**	**4**	**4**	**0**	**1**	**11**	**3**	**27**	**5**	**4**	**8**	**8**	**82**
Total - Luzon and Visayas		**9**	**5**	**6**	**7**	**5**	**14**	**7**	**29**	**8**	**15**	**12**	**9**	**126**

Occurrences of transmission line constraints in the ex-post were observed 1,412 times during the year, with the Visayas region accounting for majority of the constraints at 1,372 (97.2 percent). Bulk of which were attributable to the constraints at the Quiot-New Naga 138kV Line which totalled 1,312 or 92.9 percent of the total constraints system-wide. The Toledo-New Naga 138kV Line distantly recorded the next highest frequency at 39 constraints (2.8 percent).

Luzon accounted for the remaining 2.8 percent (40 constraints), mainly due to the constraints at the Bauang-BPPC 230kV Line (16 constraints) which is 1.1 percent of the total constraints on transmission lines during the year.

On the other hand, occurrences of constraints at the Visayas submarine cables during ex-post totalled at 1,263. 618 of these constraints were on the Negros-Panay submarine cable while 593 were constraints at the Cebu-Negros submarine cable.

Table 64. Frequency of Constraints at Transmission Lines (Ex-Post)

Frequency of Constraints on Transmission Lines (Ex-Post) - 2016														
Region	**Equipment Name**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
Luzon	Bauang-BPPC 230kV Line				7	3	5	1						16
	Binga-San Manuel 230kV Line										5			5
	Bantay-San Esteban 115kV Line										2			2
	Currimao-Bantay 115kV Line										2			2
	Laoag-Currimao 115kV Line										2			2
	Quezon (Balintawak)-San Jose 230kV Line					1								1
	Amadeo-Calaca 230kV Line				7		1							8
	Binan-Calaca 230kV Line					1								1
	Sta. Rosa-Calaca 230kV Line				2						1			3
Subtotal - Luzon		**-**	**-**	**-**	**16**	**5**	**6**	**1**	**-**	**-**	**12**	**-**	**-**	**40**
Visayas	New Naga-Cebu 138kV Line					2	3	9	2					16
	Quiot-New Naga 138kV Line		4	72	171	142	199	337	343	41			3	1,312
	Toledo-New Naga 138kV Line	1				1	33	4						39
	Amlan-Mabinay 138kV Line				1									1
	Bacolod-Cadiz 138kV Line										1	3		4
Subtotal - Visayas		**1**	**4**	**72**	**172**	**145**	**235**	**350**	**345**	**41**	**1**	**3**	**3**	**1,372**
Total - Luzon and Visayas		**1**	**4**	**72**	**188**	**150**	**241**	**351**	**345**	**41**	**13**	**3**	**3**	**1,412**

Table 65. Frequency of Constraints at Submarine Cable (Ex-Post)

Frequency of Constraints on Submarine Cables (Ex-Post) - 2016														
Region	**Equipment Name**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
Visayas	Leyte-Cebu Submarine Cable	25	9	2	1	2			7		1	5		52
	Cebu-Negros Submarine Cable			2	3	1	3	7	41	102	110	176	148	593
	Negros-Panay Submarine Cable	6	3	28	41	74	16	43	201	114	87	3	2	618
Total		**31**	**12**	**32**	**45**	**77**	**19**	**50**	**249**	**216**	**198**	**184**	**150**	**1,263**

XV. OVER-RIDING CONSTRAINTS[39]

A. Over-riding Events by Category

A total of 151,905 over-riding events[40] were recorded this year, 69.7 percent (105,918 events) of which were impositions involving Luzon generators, while 30.3 percent (45,987 events) involved Visayas generators. Of these, about 97 percent were attributable to non-security limits, accounting for a total of 147,317 events during the year. The remaining 3 percent comprising of 4,588 events, arose from the imposition of security limits.

The conduct of commercial tests, a large portion of which is attributed to commissioning tests, accounted for about 55.7 percent (82,041 events) of the total non-security related events during the year. Over-riding events categorized as “Unreported” came next, accounting for about 39.7 percent (58,493 events) of the total non-security related events during the year. Unreported events are those not reported in the daily market monitoring files sent by NGCP-SO. About 4.5 percent (6,652 events) were attributed to non-security events related to generating unit limitation while the remaining 0.1 percent (131 events) was on account of impositions due to regulatory requirements.

Security-related events on the other hand, were partly driven by the designation of must-run-units, which accounted for 35.5 percent (1,627 events) of the total security limits imposed during the year. However, bulk of the security limits imposed this year were on account of “other types recommended by the NGCP-SO” at 60.6 percent (2,780 events). The remaining 3.9 percent (181 events) of the total security limit impositions this year was due to emergency de-rating/outage of specific transmission line.

[39] Over-riding constraints, as defined in the WESM Rules, 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.

[40] 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).

It is noted that the categorization of over-riding events this year into Security Limit and Non-Security Limit followed the new categorization scheme which was adopted by the NGCP-SO beginning 24 June. The same is consistent with Clause 4.4 of the WESM Manual on Dispatch Protocol Issue 11, on the categorization of over-riding constraints[41].

Significant increase in the number of over-riding events was observed beginning the February billing month, recording an increase of 58.3 percent from the 3,611 events in January to 5,715 events. Over-riding events increased by another 64.5 percent in March to 9,400 events, and by 44.9 percent in April, as over-riding events further increased to 13,618 events related to the influx in registration of renewable energy plants vying for the Feed-in-Tariff Program. From May to December, over-riding events ranged steadily between 13,303 to a high of 16,304 events in August. The high number of over-riding events in August were on account of the increase in the security limit related events that were observed during the month driven in part by the MRU designations of Malaya TPP 1 and 2 and Leyte A GPP to provide real-power balancing and frequency control. On top of these, the commissioning tests of battery storage, biofuel, coal, geothermal, natural gas and solar plants were relatively higher in August. Categorized under commercial tests, this consequently augmented the count of over-riding constraints imposed due to non-security related events during the August billing month.

Year-on-year comparison demonstrates that over-riding events increased substantially by 186.6 percent from the 52,970 over-riding events that were recorded in the previous billing year. The substantial increase in non-security limits drove the significant increase in over-riding events this year, following the higher number of new plants which underwent commissioning tests as detailed in Table 71 below. Notable increase in the number of solar plants was observed beginning March, related to the recent growth in the registration of said resource which vied for Feed-in-Tariff (FIT) accreditation during the period.

It is worthy to note that occurrences of over-riding events followed a certain pattern across the year, demonstrating higher impositions particularly during the trading intervals 0700H to 1800H. This was on account of the conduct of commissioning tests of solar plants, reaching a maximum of 27 events in a single trading interval in the August billing month.

Table 66. Summary of Over-riding Events by Category

Category	Summary of Over-riding Events by Category - 2016												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Luzon													
Non-Security Limits	2,855	4,948	7,254	9,594	8,654	9,391	9,143	10,457	10,595	9,679	10,918	10,969	104,457
Security Limits					432	337	277	415					1,461
Subtotal - Luzon	**2,855**	**4,948**	**7,254**	**9,594**	**9,086**	**9,728**	**9,420**	**10,872**	**10,595**	**9,679**	**10,918**	**10,969**	**105,918**
Visayas													
Non-Security Limits	756	767	2,146	4,024	3,904	4,200	5,009	5,345	4,962	3,988	4,054	3,705	42,860
Security Limits					43	36		87	20	1,324	863	754	3,127
Subtotal - Visayas	**756**	**767**	**2,146**	**4,024**	**3,947**	**4,236**	**5,009**	**5,432**	**4,982**	**5,312**	**4,917**	**4,459**	**45,987**
Grand Total	**3,611**	**5,715**	**9,400**	**13,618**	**13,033**	**13,964**	**14,429**	**16,304**	**15,577**	**14,991**	**15,835**	**15,428**	**151,905**

[41] Clause 4.4 of the WESM Manual on the Dispatch Protocol Issue 11.0 categorized the imposition of over-riding constraints as follows: (1) Security Limits – must run units (MRU), emergency de-rating/outage of specific transmission lines, other types as may be recommended by the SO. (2) Non-Security Limits – Regulatory and Commercial Testing, generating unit limitations.

Table 67. Summary of Reasons for Over-riding Events

Reason	Summary of Over-Riding Events by Category - 2016												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Reasons for Non-Security Limits													
Commercial Test							13,238	15,007	14,576	12,552	13,503	13,165	82,041
Generating Unit Limitation							914	771	975	1,026	1,469	1,497	6,652
Regulatory Requirements								24	6	89		12	131
Unreported	3,611	5,715	9,400	13,618	12,558	13,591							58,493
Subtotal - Non-Security Limits	**3,611**	**5,715**	**9,400**	**13,618**	**12,558**	**13,591**	**14,152**	**15,802**	**15,557**	**13,667**	**14,972**	**14,674**	**147,317**
Reasons for Security Limits													
Emergency de-rating / Outage of Specific Transmisison Line										179		2	181
Must-Run-Units (MRU)					475	373	277	502					1,627
Other Types as maybe Recommended by SO									20	1,145	863	752	2,780
Subtotal - Security Limits					**475**	**373**	**277**	**502**	**20**	**1,324**	**863**	**754**	**4,588**
Grand Total	**3,611**	**5,715**	**9,400**	**13,618**	**13,033**	**13,964**	**14,429**	**16,304**	**15,577**	**14,991**	**15,835**	**15,428**	**151,905**

B. Over-riding Events by Plant Type

Solar plants contributed the bulk of over-riding events, accounting for 53.9 percent (81,950 events) of the total impositions during the year. Coal plants came next at a distant 17.1 percent (26,048 events) followed by biofuel and wind plants at 8.8 percent (13,297 events) and 8.1 percent (12,254 events), respectively. Meanwhile, over-riding events involving hydro plants accounted for 4.5 percent (6,880 events) of the total events across the year.

All impositions on solar plants were on account of non-security related events, about 66 percent of which were due to commissioning tests. Similarly, majority of the non-security constraints on biomass and hydro plants were likewise on account of commissioning tests, while those on wind plants were primarily due to generating unit limitations.

NWPDC Wind 2 topped the list of plants with over-riding constraint impositions during the year, recording a total of 7,867 events. These impositions were all on account of non-security related constraints substantially due to generating unit limitations specifically related to its pending configuration of the Market Participant Interface (MPI). SLPGC CFTPP came next with a total of 7,639 non-security related events, majority of which were unreported, while a considerable portion was due to the conduct of commissioning tests. TPC (Sangi) CFTPP, Gift Biomass, Villasiga MHEP and Anda CFTPP came next with a total each of 6,464 events, 6,394 events, 5,935 events and 5,464 events. MEC Solar and Valenzuela Solar followed, recording non-security related events at a high of 3,937 events and 3,683 events, respectively.

Table 68. Summary of Over-riding Events by Plant Type

Plant Type	Summary of Over-riding Events by Plant Type - 2016												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
BAT							28	524	168	609	612	536	2,477
BIOF	737	1,110	1,493	1,334	737	722	686	703	1,071	1,305	1,854	1,545	13,297
COAL	1,112	2,472	2,512	2,909	2,722	2,910	2,709	2,697	1,613	1,066	1,821	1,505	26,048
GEO			44				39	496	613	912	498	756	3,358
HYD	115	63	241	495	472	733	769	704	849	791	764	884	6,880
NATG	339	27	7	76	263	531	864	588	616	309	42	109	3,771
OIL	21	25	37	183	464	376	277	454	19	14			1,870
SOLR	341	952	3,775	7,511	7,394	7,988	8,357	9,409	9,712	9,042	8,816	8,653	81,950
WIND	946	1,066	1,291	1,110	981	704	700	729	916	943	1,428	1,440	12,254
Grand Total	**3,611**	**5,715**	**9,400**	**13,618**	**13,033**	**13,964**	**14,429**	**16,304**	**15,577**	**14,991**	**15,835**	**15,428**	**151,905**

C. Impact of Over-riding Events

The imposition of over-riding constraints on generators[42] affected 8,737 trading intervals or 99.5 percent of the total trading intervals in 2016. This augmented the effective supply[43] level at an average of 356 MW, remarkably higher than last year's 147 MW.

[42] Excluding the other constraints considered in the MMS (e.g. ramp rate offers).

Supply rose from an average of 67 MW in January to a high of 675 MW in August. The highest supply increase was recorded at 1,455 MW on 04 August at 1200H, mainly due to the high incidence of commissioning tests involving San Gabriel NGPP, SLPGC CFTPP, PCPC CFTPP, Avion NGPP, Cadiz Solar, TPC (Sangi) CFTPP) and Anda CFTPP, as well as the MRU designation on Malaya TPP for real-power balancing and frequency control.

The imposition of over-riding constraints likewise resulted in higher Pmin or price taker levels in almost all the trading intervals during the 2016 billing period, corresponding to an average increase in Pmin of 461 MW, an increase from the 197 MW posted in the previous year. The highest Pmin level increase was posted in August at an average of 751 MW. Note that the ratio of Pmin to the demand during year was 44.9 percent. Taking into account the effect of the imposed over-riding constraints on the Pmin level, the ratio increased to 48.8 percent, providing an indication on the reduction in contestable demand by about 4.0 percent.

Table 69. Impact on Supply Summary

Increase/Decrease in Supply (Offers and Nominations with Limit)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Grand Total
-650 MW to -600 MW	-	-	-	-	-	-	-	-	-	-	-	-	-
-600 MW to -550 MW	-	-	-	-	-	-	-	-	-	-	-	-	-
-550 MW to -500 MW	-	-	-	-	-	-	-	-	-	-	-	-	-
-500 MW to -450 MW	0.1	-	-	-	-	-	-	-	-	-	-	-	0.0
-450 MW to -400 MW	-	-	-	-	-	-	-	-	-	-	-	-	0.0
-400 MW to -350 MW	-	-	-	-	-	-	-	-	-	-	-	-	-
-350 MW to -300 MW	-	-	-	-	-	-	-	-	-	-	-	-	-
-300 MW to -250 MW	-	-	-	-	-	-	-	-	-	0.1	-	-	0.0
-250 MW to -200 MW	-	-	-	-	-	-	-	-	-	0.4	-	0.3	0.1
>-200 MW to -150 MW	-	-	-	-	-	-	-	-	0.1	0.7	-	0.1	0.1
>-150 MW to -100 MW	0.3	0.3	-	0.1	-	-	0.3	-	0.1	0.7	-	0.3	0.2
>-100 MW to -50 MW	1.2	0.8	0.1	0.1	-	-	-	-	0.4	4.7	1.2	1.0	0.8
>-50 MW to >0 MW	23.1	0.3	2.9	-	-	-	-	-	2.8	10.8	5.7	4.4	4.2
>0 MW to 50 MW	31.0	0.1	5.5	0.1	-	0.3	1.4	0.4	9.9	16.1	3.1	10.3	6.5
>50 MW to 100 MW	8.4	4.4	2.6	1.2	-	0.1	1.4	0.3	6.6	7.5	8.7	11.7	4.4
>100 MW to 150 MW	21.5	20.3	3.5	1.6	-	0.9	2.1	0.8	2.8	7.1	16.0	17.2	7.9
>150 MW to 200 MW	8.6	26.5	3.0	4.7	-	1.7	3.6	7.7	6.6	6.7	14.5	14.9	8.3
>200 MW to 250 MW	2.4	17.5	9.9	7.1	0.1	2.4	9.2	4.4	4.3	6.8	12.4	7.6	7.0
>250 MW to 300 MW	0.5	16.0	17.8	12.0	6.5	12.0	8.9	1.6	3.2	5.0	9.3	6.1	8.2
>300 MW to 350 MW	2.0	9.3	18.1	14.9	8.6	13.4	7.4	2.1	2.7	5.1	6.2	6.3	8.0
>350 MW to 400 MW	0.3	2.7	10.1	11.2	8.8	8.9	5.7	3.4	3.8	12.5	6.1	5.8	6.6
>400 MW to 450 MW	0.1	1.1	11.5	5.9	19.5	7.5	6.4	6.7	9.7	3.8	6.1	4.3	6.8
>450 MW to 500 MW	0.1	0.7	5.5	6.2	11.7	5.8	4.4	5.6	10.3	1.9	4.7	4.3	5.1
>500 MW to 550 MW	0.3	-	3.5	4.0	4.7	6.7	4.4	2.9	3.9	1.4	2.7	2.6	3.1
>550 MW to 600 MW	-	-	2.0	4.9	3.3	5.1	6.3	5.5	3.5	1.3	2.3	1.3	3.0
>600 MW to 650 MW	-	-	2.3	4.4	5.4	4.8	4.6	4.5	4.1	1.5	0.5	0.8	2.7
>650 MW to 700 MW	-	-	0.6	5.1	2.9	5.4	6.5	6.4	3.2	2.1	0.4	0.3	2.7
>700 MW to 750 MW	-	-	-	5.2	4.0	4.3	5.4	4.9	3.7	2.1	-	-	2.5
>750 MW to 800 MW	-	-	0.3	5.6	4.0	3.4	4.4	4.0	3.4	1.1	-	0.3	2.2
>800 MW to 850 MW	-	-	0.1	2.5	5.1	4.0	3.3	5.6	4.5	0.3	-	0.1	2.1
>850 MW to 900 MW	-	-	-	1.9	5.1	4.3	2.8	8.1	4.2	0.3	-	-	2.2
>900 MW to 950 MW	-	-	0.6	0.8	3.3	2.4	2.8	4.8	3.0	-	-	-	1.5
>950 MW to 1000 MW	-	-	0.1	0.4	6.7	6.5	8.8	20.3	3.0	-	-	-	3.8
>1000 MW	-	-	-	-	-	-	-	-	-	-	-	-	-

Table 70. Impact on Pmin Summary

Increase/Decrease in Pmin Level (Price Taker)	Jan	Feb	Mar	Apr	May	June	Jul	Aug	Sept	Oct	Nov	Dec	Total
Below 0 MW	0.9	-	-	-	-	-	-	-	0.1	0.7	-	-	0.1
>0 MW to 50 MW	3.4	-	0.1	-	-	-	-	-	4.9	11.4	3.7	0.3	2.0
>50 MW to 100 MW	33.0	-	2.6	-	-	-	-	-	9.3	8.2	3.1	2.9	5.0
>100 MW to 150 MW	9.1	0.1	4.9	-	-	-	1.1	-	6.2	14.0	8.4	14.0	4.8
>150 MW to 200 MW	10.0	7.4	2.3	1.2	-	-	0.8	0.3	2.6	6.8	7.2	14.0	4.4
>200 MW to 250 MW	13.8	22.2	2.7	3.3	-	1.1	1.4	7.4	3.1	7.5	18.7	16.5	8.2
>250 MW to 300 MW	11.3	27.1	4.5	6.3	-	0.9	4.4	3.8	7.0	7.1	14.9	12.4	8.4
>300 MW to 350 MW	3.7	17.2	14.8	10.7	8.1	4.6	9.0	1.8	3.7	5.6	8.9	6.9	7.9
>350 MW to 400 MW	3.9	15.5	19.4	17.4	3.5	12.8	8.8	1.4	2.2	6.0	6.2	5.4	8.5
>400 MW to 450 MW	7.2	7.4	15.4	11.5	9.0	11.3	8.1	4.2	2.8	7.8	4.3	6.3	7.9
>450 MW to 500 MW	1.8	1.5	9.5	7.1	20.3	9.8	5.3	5.6	9.1	8.3	6.6	5.4	7.5
>500 MW to 550 MW	0.9	1.2	9.5	5.6	13.2	7.7	6.4	7.0	8.8	2.8	6.1	4.2	6.1
>550 MW to 600 MW	0.1	0.4	4.0	4.8	5.3	5.4	3.5	2.9	5.7	2.1	4.6	4.2	3.6
>600 MW to 650 MW	0.5	-	3.3	3.8	2.2	5.2	5.6	3.8	3.8	1.8	3.7	1.9	3.0
>650 MW to 700 MW	0.3	-	2.6	4.1	4.3	5.9	4.3	4.8	3.8	1.8	1.2	1.1	2.8
>700 MW to 750 MW	-	-	1.3	5.1	5.0	5.2	4.9	6.3	3.2	2.1	0.8	1.7	3.0
>750 MW to 800 MW	-	-	0.7	4.8	3.2	4.2	7.1	4.4	1.9	1.9	0.4	1.1	2.5
>800 MW to 850 MW	-	-	0.1	4.8	4.2	3.5	5.3	5.2	3.4	1.4	0.1	0.4	2.4
>850 MW to 900 MW	-	-	0.4	3.4	3.6	3.9	5.1	7.3	3.5	1.7	-	0.3	2.4
>900 to 1000 MW	-	-	0.7	2.2	5.1	3.9	3.1	6.4	3.2	0.7	0.1	0.4	2.2
>1000 MW	-	-	1.0	4.0	12.9	14.7	16.0	27.4	11.6	0.4	0.9	0.6	7.5

[43] The supply is equal to the total offered capacity of all generator resources and nomination level from non-scheduled generators, adjusted for any security limit provided by the NGCP-System Operator.

Table 71. Summary of Commissioning Levels (MW)

Summary of Commissioning Levels, 26 Dec 2015 to 25 Dec 2016							
Plant Name	**Node ID**	**Registered Capacity**	**Registration Date**	**Start Date of Over-Riding Events**	**End Date of Over-Riding Events**	**Number of Over-Riding Events**	**Commissioning levels, MW[1] (Min-Max)**
MASINLOC BATTERY	1MSNLO_BATG	10	July 2, 2016	July 11, 2016		2,477	10
Sub-Total (Battery Energy Storage)		***10.0***				***2,477***	
ASEAGAS BIOMASS	3LIAN_G01	7.3	August 26, 2016	September 5, 2016		2,511	0.5-8.8
GIFT BIOMASS	1GIFT_G01	12	January 20, 2016	November 5, 2016		6,394	2.4-11
IBEC BIOMASS	1IBEC_G01	18	August 27, 2015	November 5, 2015	April 11, 2016	2,443	5-8
BICOL BIOMASS	3BBEC_G01	5	September 7, 2016	January 26, 2016		1,033	4.4
Sub-Total (Biofuel)		***42.3***				***12,381***	
ANDA CFTPP	1ANDA_G01	82	May 9, 2015	January 25, 2016	September 27, 2016	5,464	25-75
SLPGC CFTPP	3SLPGC_G01	150	February 22, 2015	February 14, 2016	October 27, 2016	3,883	10-150
	3SLPGC_G02	150	February 22, 2015	January 27, 2016	December 9, 2016	3,727	10-150
SLTEC CFTPP	3SLTEC_G02	135	August 15, 2015	December 29, 2015	February 20, 2016	509	5-126
SMC LIMAY CFTPP	1SMC_G01	150	November 4, 2016	November 4, 2016		610	5-150
Sub-Total (Coal)		***667.0***				***14,193***	
AVION NGPP	3AVION_G01	97	August 11, 2015	February 5, 2016	September 25, 2016	845	5-100
SAN GABRIEL NNGP	3SNGAB_G01	414.1	March 2, 2016	April 13, 2016	October 25, 2016	1,913	5-430
Sub-Total (Natural Gas)		***511.1***				***2,758***	
ARMENIA SOLAR	1ARMSOL_G01	7.1	April 8, 2016	March 31, 2016		3,253	0-7.1
BOSUNG SOLAR	1BOSUNG_G01	1	June 22, 2016	July 9, 2016		1,899	0.1-0.8
CALATAGAN SOLAR	3CALSOL_G01	50	February 22, 2016	February 24, 2016		3,533	0-47.3
CLARK SOLAR	1CLASOL_G01	18	March 9, 2016	March 11, 2016		3,332	0.5-16.1
CURRIMAO SOLAR	1MAEC_G01	16.32	February 20, 2016	February 20, 2016		3,672	0-18.4
DALAYAP SOLAR	1DALSOL_G01	5.88	April 8, 2016	March 31, 2016		3,220	0-5.7
FCRV SOLAR	1CABSOL_G01	9.075	March 15, 2016	March 19, 2016		3,266	0.1-8.3
HERMOSA SOLAR	1YHGRN_G01	14.5	January 20, 2016	February 5, 2016		3,593	0-10.8
LIAN SOLAR	3ADISOL_G01	1.6	March 10, 2016	March 16, 2016		3,136	0-13.5
MARIVELES SOLAR	1MARSOL_G01	16	March 15, 2016	March 15, 2016		3,543	0-17.3
MEC SOLAR	3MEC_G01	32.9	January 6, 2015	December 26, 2015		3,937	0.5-31
MORONG SOLAR	1BTNSOL_G01	5	March 14, 2016	March 23, 2016		1,922	0-4
PALAUIG SOLAR	1ZAMSOL_G01	5	March 10, 2016	March 23, 2016		2,205	0-4.3
RASLAG II SOLAR	1RASLAG_G02	13.14	February 23, 2016	February 25, 2016	March 15, 2016	205	0.5-11
SAN ILDEFONSO SOLAR	1BULSOL_G01	15	March 11, 2016	March 16, 2016		2,998	0-12.4
SAN RAFAEL SOLAR	1SPABUL_G01	1.2	March 15, 2016	March 31, 2016		2,099	0-3.7
SUBIC SOLAR	1SUBSOL_G01	7.14	April 15, 2016	April 16, 2016		2,879	0-5.6
TARLAC SOLAR	1PETSOL_G01	50	January 22, 2016	January 27, 2016	December 2, 2016	2,309	0.2-50
VALENZUELA SOLAR	2VALSOL_G01	8.5	March 3, 2016	February 24, 2016		3,683	0-7.9
Sub-Total (Solar)		***277.4***				***54,684***	
PILILIA WIND	3AWOC_G01	54	August 14, 2015	March 5, 2016	May 12, 2016	1,144	0.4-39
Sub-Total (WInd)		***105.9***				***1,144***	
Total (Luzon)		***1,626***				***87,637***	
HPCO BIOMASS	6HPCO_G01	3	January 6, 2015	March 12, 2016	May 27, 2016	916	1.9-2.7
Sub-Total (Biofuel)		***3.0***				***916***	
PCPC CFTPP	8PALM_G01	135	March 23, 2016	May 30, 2016	August 16, 2016	773	2.6-135
PEDC CFTPP	8PEDC_U03	150	August 19, 2016	August 20, 2016		1,404	0-154.5
Sub-Total (Coal)		***285***				***2,177***	
VILLASIGA MHEP	8SUWECO_G01	8	January 4, 2016	March 12, 2016	December 25, 2016	5,935	0.1-8.1
Sub-Total (Hydro)		***8.0***				***5,935***	
BAIS SOLAR	6MNTSOL_G01	14.4	February 24, 2016	March 12, 2016	October 25, 2016	2,636	0.1-12.7
CADIZ SOLAR	6HELIOS_G01	108.12	February 29, 2016	March 12, 2016		3,652	0-116.1
COSMO SOLAR	8COSMO_G01	5.67	May 25, 2016	June 16, 2016		2,417	0-5
FTOLEDO SOLAR	5TOLSOL_G01	49	June 29, 2016	October 26, 2016		780	0-40.5
ISLASOL II SOLAR	6CARSOL_G01	27.2	March 1, 2016	March 12, 2016		3,439	0.2-23.6
ISLASOL III SOLAR	6MANSOL_G01	40.5	March 4, 2016	March 13, 2016	October 18, 2016	2,553	0.1-45.5
SEPALCO SOLAR	4SEPSOL_G01	45	March 15, 2016	March 24, 2016		3,522	0.1-38.6
SILAY SOLAR	6SLYSOL_G01	20	March 8, 2016	March 12, 2016		3,674	0-20.2
SN CARLOS SUN SOLAR	6SACSUN_G01	46.8	March 8, 2016	March 12, 2016		3,071	3.2-47
TOLEDO SOLAR	5TOLSOL_G01	49	June 29, 2016	June 30, 2016	October 25, 2016	1,514	0-48.9
Sub-Total (Solar)		***405.7***				***27,258***	
Total (Visayas)		***701.7***				***36,286***	
Grand Total (LUZON & VISAYAS)[2]		***2,327.3***				***123,923***	

[1]Based on security limit imposed by the NGCP-SO

XVI. GENERATION MIX[44]

A. Generation Mix by Plant Type

The market proved to be evolving with the addition this year of the Masinloc Power Partners Co. Ltd. (MPPCL)'s 10 MW-battery energy storage beginning 02 July, and the visibly increasing contribution of renewable energy technologies – solar, wind and biomass, into the market's generation mix.

In the Luzon region, coal plants accounted for an average of about 48.5 percent of the generation mix based on metered quantities, followed by natural gas plants with 32 percent. Hydro, geothermal and oil-based plants came at distant third, fourth and fifth, providing 8.1 percent, 6.5 percent and 2.4 percent respectively, of the total generation in the region. Looking at the Figures below, Luzon coal plants contributed higher generation during the summer months of April and May while the generation mix of hydro plants dropped during these months. On the other hand, Luzon oil-based plants recorded higher generation mix in August, consistent with the higher market prices during the period.

Preferential dispatch plants – biomass, solar and wind, expanded its contribution to the generation mix at 2.6 percent this year. The same was higher when compared to last year's 1.4 percent. This followed the growth in the participation of solar plants in the market, from last year's 0.1 percent to an average of 0.6 percent this year, as well as biomass plants, from last year's 0.3 percent to 0.7 percent. Wind plants likewise registered higher generation mix in 2016 at 1.2 percent, from 1 percent. Consequently, decline in the generation mix of natural gas, hydro and geothermal plants was observed from last year's 33.3 percent, 8.3 percent, and 6.8 percent. Coal plants, on the other hand, recorded a slight increase from last year's 48.4 percent while oil-based plants rose from an average of 1.7 percent last year.

The Visayas region demonstrated the same trend, with 2016 recording the notable rise in the generation contributed by preferential dispatch plants, particularly of solar plants, in the region's generation mix based on metered quantities. Notwithstanding, the generation mix of geothermal plants in the Visayas remained firm at an average of 50.8 percent, though this was lower than last year's 55.7 percent. Coal plants came next, providing 36.8 percent of the generation mix in the region, a slight decline from the 36.6 percent posted in 2015.

Preferential dispatch plants in Visayas came in third place, with a combined generation mix averaging at 8.0 percent, driven by the notably higher mix contributed by solar plants at 4.8 percent from only 0.7 percent in the previous year. Following the same trend, wind and biofuel plants recorded a generation mix of 1.8 percent and 1.4 percent, respectively, higher than last year's 1.5 percent and 1.1 percent. Finally, oil-based plants registered an average of 3.9 percent, lower than last year's 4.2 percent. The increase in the contribution of oil-based plants was observed particularly during the June and August billing months at 6.6 percent and 5.8 percent, respectively, when market prices are also relatively higher.

It is important to note the significant increase in the generation mix of Visayas solar plants which clearly manifested beginning March, from an average of only 1.1 percent in February to 4.2 percent in March to a high of 6.4 percent in September. This growth is consistent with the exceptional increase in the market registration of solar plants which vied for the Feed-in-Tariff (FIT) accreditation during the period.

[44] Generation based on metered quantity (energy injected) by resource type per billing month

Figure 57. Generation Mix – System

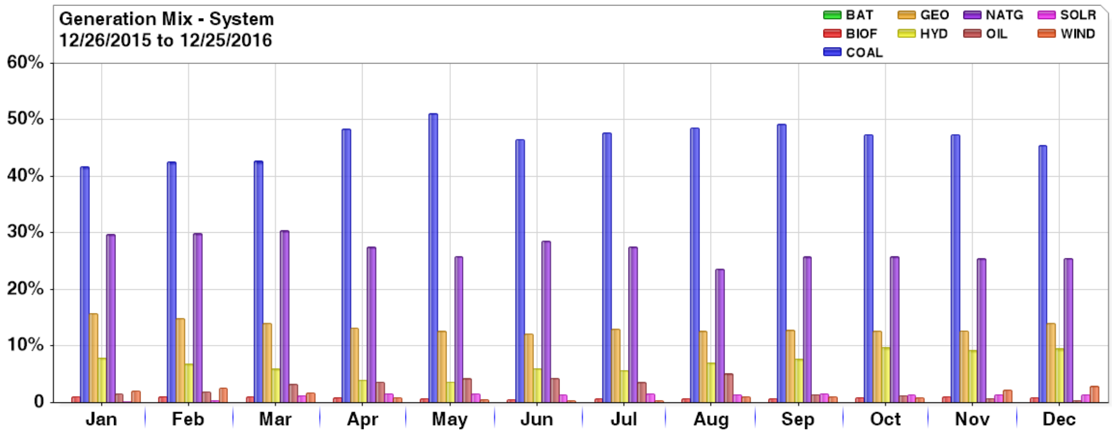


Figure 58. Generation Mix – Luzon

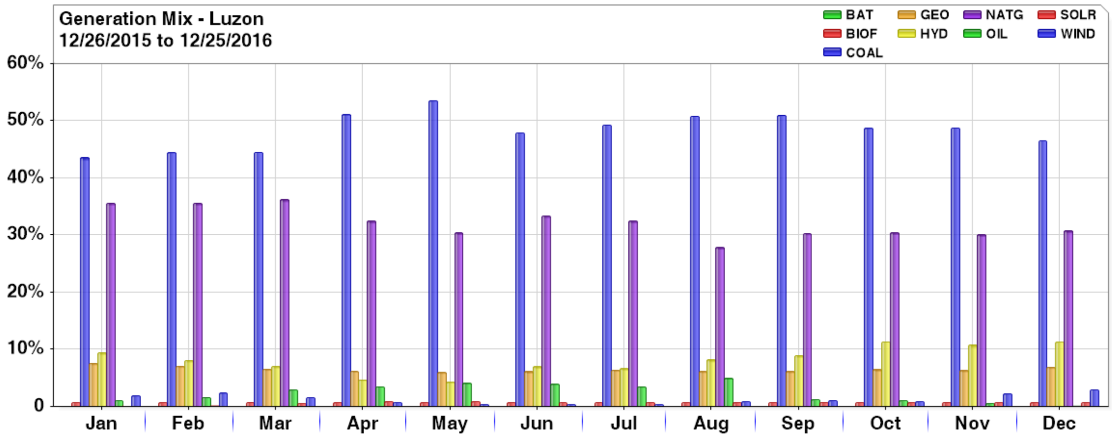
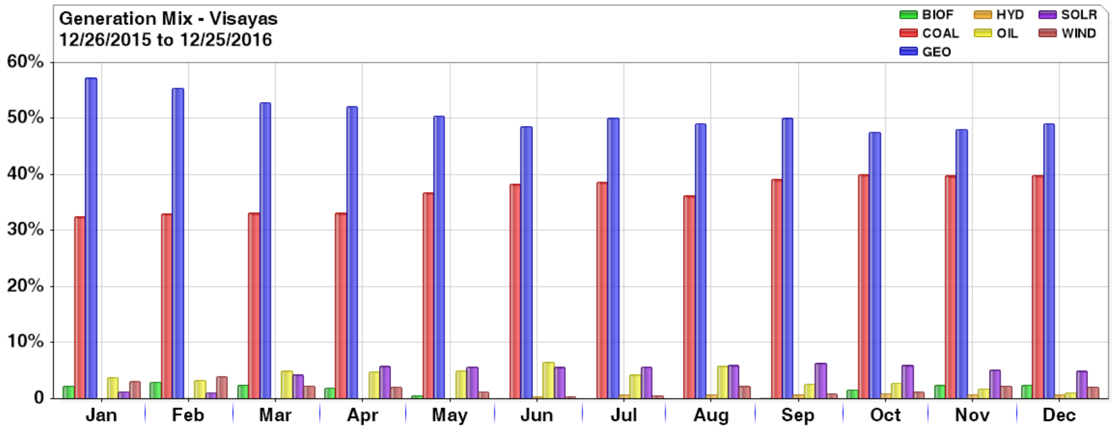


Figure 59. Generation Mix – Visayas



B. Generation Mix vs. Price[45]

Comparison of system-wide generation mix with the corresponding generator prices during the billing year showed that coal plants, which provided 46.1 percent of the total generation during the year, had prices averaging at PhP2,691/MWh. On the other hand, natural gas plants which provided 27.1 percent of the total generation, recorded higher prices averaging at PhP2,854/MWh. Meanwhile, 13.3 percent of the generation mix from geothermal plants were priced at an average of PhP2,629/MWh.

The market price attributed to hydro plants was even higher, averaging at PhP3,449/MWh, corresponding to about 6.9 percent of the generation mix during the year. Oil-based plants, on the other hand, posted the highest generation price which averaged at PhP5,584/MWh, accounting for about 2.6 percent of the generation mix.

Battery storage plants which posted the lowest contribution to the generation mix, also posted the lowest price averaging at PhP2,237/MWh during the year.

Meanwhile, generation prices of preferential dispatch plants – biomass, solar and wind, averaged at PhP2,753/MWh, PhP2,951/MWh and PhP2,489/MWh, respectively throughout the year. Biomass plants accounted for 0.8 percent of the system-wide generation mix while solar and wind plants had 1.3 percent. Note however, that renewable energy plants which were accredited under the Feed-in-Tariff (FIT) mechanism are price takers in the market and will be paid a fixed tariff in accordance with the Feed-in-Tariff Rules.

In terms of monthly trend, coal plants, which recorded its lowest generation mix in 2016 during the first quarter, likewise posted lower generator prices during the period, particularly in January and February which recorded its lowest monthly price at PhP1,965/MWh and PhP2,177/MWh, respectively. Conversely, geothermal plants posted its highest contribution to the generation mix during the first quarter of the year coupled with low prices particularly in January and February at an average of PhP1,836/MWh and PhP2,121/MWh. Natural gas plants likewise posted its highest generation mix during this period in the first quarter, while low generation mix was posted during the second half of the year, the lowest being during the August billing month. Its highest monthly price was posted in June and August averaging at PhP4,552/MWh and PhP4,103/MWh. Similarly, the highest monthly price of coal and geothermal plants were posted during the June and August billing months, though still slightly lower than the price of natural gas plants during these months.

Hydro plants posted low contribution to the generation mix from April to July, and posted its highest monthly price in June at PhP6,055/MWh. Higher generation mix was observed from hydro plants during the last quarter of the year, coupled with relatively lower prices, the lowest being at PhP2,315/MWh during the December billing month

On the other hand, oil-based plants, which recorded its highest generation mix during the June and August billing months at 4.3 percent and 5.1 percent, respectively, likewise recorded its highest generation prices during these months, the highest among all plant types at PhP7,795/MWh and PhP8,234/MWh, respectively. Conversely, its lowest contribution to the generation mix was posted in November and December with average prices posted at PhP3,627/MWh and PhP7,623/MWh, respectively.

Year-on-year comparison showed that the generation prices of all plant types were lower this year when compared to the previous year, and that following the higher generation mix of preferential dispatch plants this year, other plant types were observed to have posted a

[45] Market prices as used in this section refers to the ex-ante weighted average price of generators according to plant type

general decrease in their respective contribution to the generation mix, except for coal plants which posted a slightly higher 0.1 percent increase this year (from 46.6 percent to 46.7 percent), and oil-based plants, which posted a 0.5 percent increase from last year's 2.1 percent to 2.6 percent.

Figure 60. Generation Mix vs. Price – System

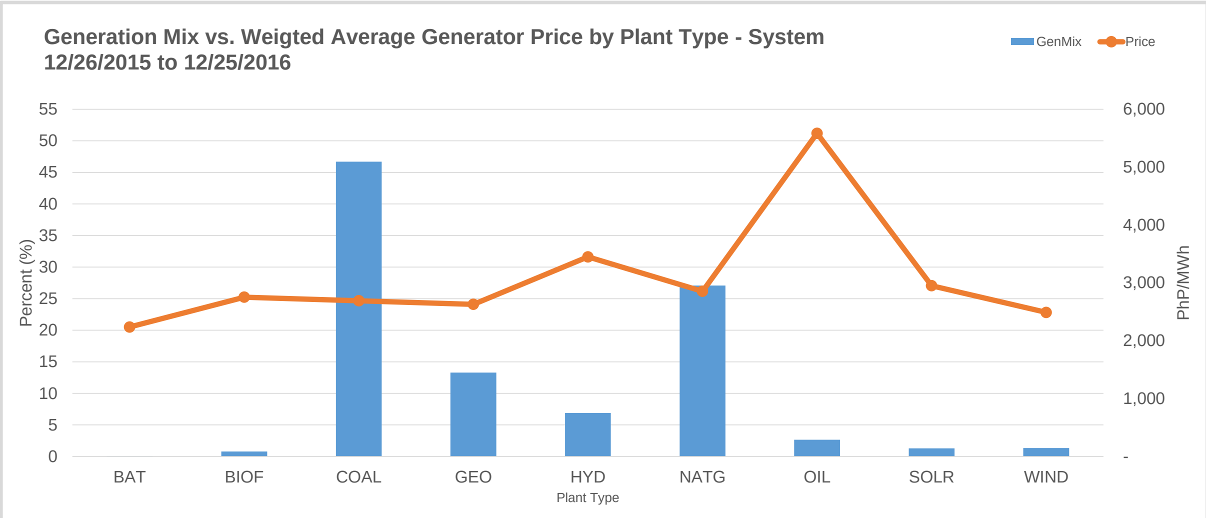


Table 72. Generation Mix vs. Price – System

Plant Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
	Generation Mix vs. Price - System												
	Generation Mix (%)												
BAT	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0	0.0
BIOF	1.0	1.0	1.0	0.9	0.6	0.6	0.6	0.7	0.6	0.9	1.0	0.9	0.8
COAL	41.7	42.6	42.7	48.3	51.0	46.6	47.7	48.6	49.2	47.4	47.4	45.4	46.7
GEO	15.8	14.9	14.0	13.2	12.6	12.1	13.0	12.6	12.7	12.6	12.7	14.0	13.3
HYD	7.9	6.8	5.9	4.0	3.7	6.0	5.7	7.0	7.7	9.8	9.3	9.5	6.9
NATG	29.7	29.9	30.4	27.5	25.9	28.6	27.6	23.6	25.8	25.8	25.5	25.5	27.1
OIL	1.5	1.8	3.2	3.7	4.2	4.3	3.6	5.1	1.4	1.3	0.7	0.4	2.6
SOLR	0.3	0.4	1.2	1.6	1.5	1.4	1.5	1.4	1.6	1.4	1.4	1.4	1.3
WIND	2.0	2.6	1.7	0.9	0.5	0.4	0.4	1.0	1.0	0.8	2.2	2.8	1.3
	Weighted Average Generator Price by Plant Type (PhP/MWh)												
BAT							2,979	2,684	2,127	2,049	1,743	1,837	2,237
BIOF	1,840	2,163	3,170	3,229	2,611	4,492	2,611	3,743	2,660	2,372	2,269	1,881	2,753
COAL	1,965	2,177	3,024	3,149	2,564	4,152	2,595	3,581	2,535	2,310	2,189	2,056	2,691
GEO	1,836	2,121	2,965	3,071	2,433	4,326	2,512	3,608	2,521	2,094	2,176	1,886	2,629
HYD	2,351	2,537	4,080	4,602	3,334	6,055	3,438	4,625	3,180	2,531	2,336	2,315	3,449
NATG	1,887	2,235	3,160	3,257	2,654	4,552	2,706	4,103	2,771	2,508	2,270	2,148	2,854
OIL	4,448	3,583	5,801	5,978	3,837	7,795	5,792	8,234	6,401	3,893	3,627	7,623	5,584
SOLR	2,931	2,809	3,028	3,464	2,687	4,683	3,182	3,960	2,667	2,049	2,179	1,770	2,951
WIND	1,233	1,893	2,685	2,661	2,779	5,247	2,115	2,758	2,671	1,897	2,063	1,863	2,489

Table 73. Year-on-Year Comparison, Generation Mix vs. Price - System

	BAT	BIOF	COAL	GEO	HYD	NATG	OIL	SOLR	WIND
	Year-on-Year Comparison, Generation Mix vs. Price - System								
	Generation Mix (%)								
2016	0.0	0.8	46.7	13.3	6.9	27.1	2.6	1.3	1.3
2015		0.4	46.6	14.5	7.0	28.1	2.1	0.2	1.1
Y-Y % Change		0.4	0.1	(1.2)	(0.1)	(1.0)	0.5	1.1	0.2
	Weighted Average Generator Price by Plant Type (PhP/MWh)								
2016	2,237	2,753	2,691	2,629	3,449	2,854	5,584	2,951	2,489
2015		3,660	3,571	3,468	4,409	3,663	7,402	5,124	3,107
Y-Y % Change		(24.8)	(24.6)	(24.2)	(21.8)	(22.1)	(24.6)	(42.4)	(19.9)

Coal plants in Luzon dominated the regional generation mix with 48.5 percent at prices which averaged at PhP2,690/MWh, followed by natural gas plants with 32 percent of the regional generation mix at n prices averaging at PhP2,854/MWh. On the other hand, Luzon oil-based plants, with 2.4 percent of the generation mix, had the highest generation price at PhP5,634/MWh. Hydro plants came next, with an average price of PhP3,454/MWh, accounting for 8.1 percent of the generation mix in Luzon. Meanwhile, geothermal plants, which contributed 6.5 percent to the Luzon generation mix, had one of the cheapest prices in the region, averaging at PhP2,671/MWh.

In the Visayas, geothermal plants provided the majority which was 50.8 percent of the total generation in the region, with prices averaging at PhP2,598/MWh. Coal plants followed with 36.8 percent of the generation mix at prices which averaged at PhP2,709/MWh. Oil-based plants had the highest generator price in Visayas averaging at PhP5,599/MWh, accounting for 3.9 percent of the generation mix.

All plant types exhibited the same behaviour in June and August, as these months obtained the highest monthly weighted average price for all plant types during the year. It was also observed that generation prices of geothermal, hydro, oil and solar plants were higher in Luzon than in Visayas. Conversely, Visayas coal and biomass plants recorded higher generation prices than the coal and biomass plants in Luzon.

Figure 61. Generation Mix vs. Price – Luzon

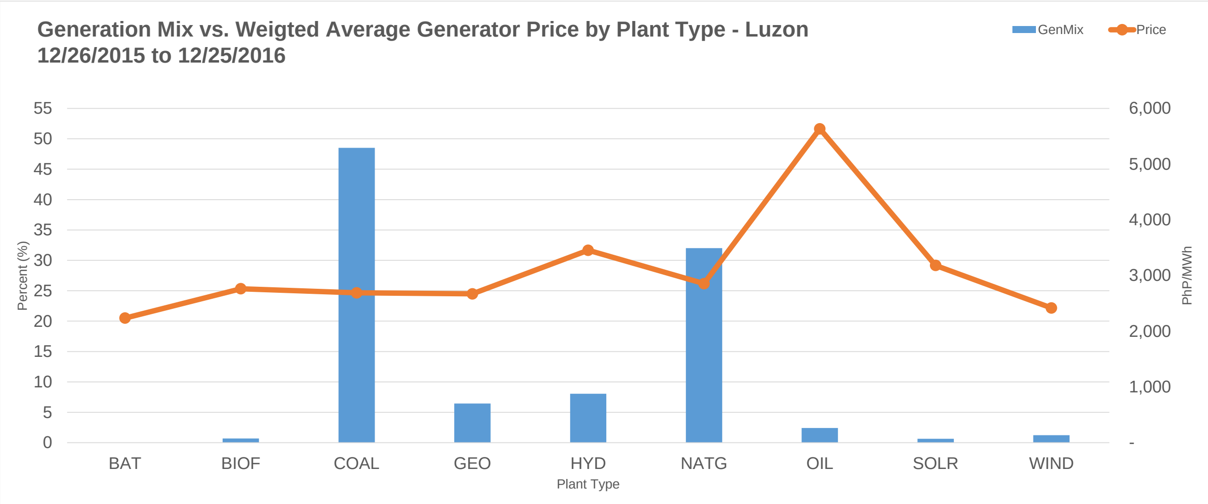


Figure 62. Generation Mix vs. Price – Visayas

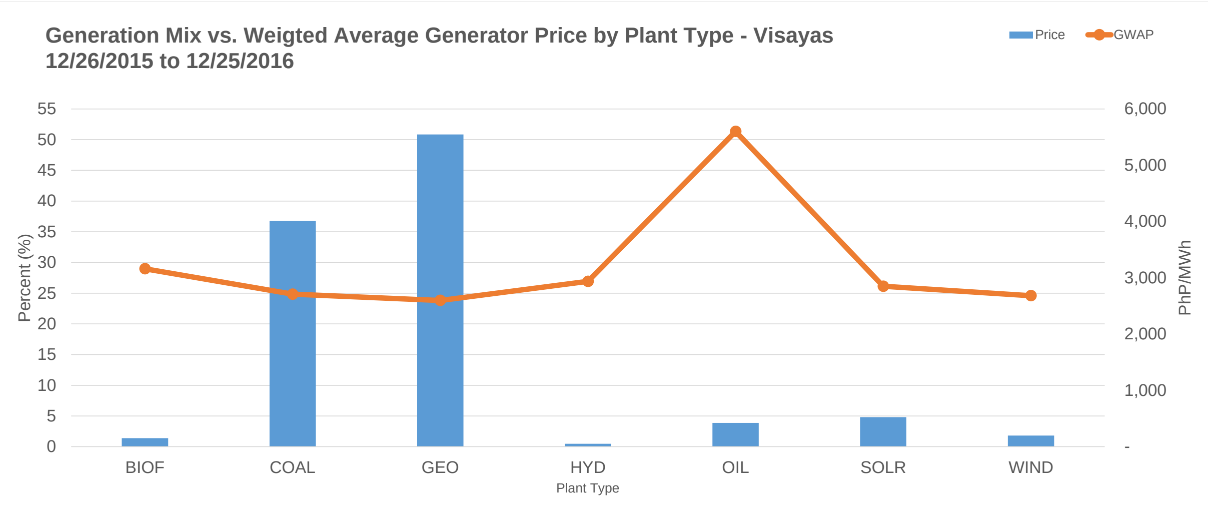


Table 74. Generation Mix vs. Price – Luzon

Plant Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
	Generation Mix vs. Price - Luzon												
	Generation Mix (%)												
BAT	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0	0.0
BIOF	0.7	0.7	0.7	0.7	0.6	0.6	0.7	0.8	0.7	0.7	0.7	0.6	0.7
COAL	43.6	44.4	44.5	51.1	53.5	47.9	49.3	50.8	50.9	48.7	48.8	46.5	48.5
GEO	7.6	7.1	6.6	6.2	6.0	6.1	6.4	6.1	6.1	6.4	6.3	6.9	6.5
HYD	9.5	8.1	7.0	4.7	4.3	6.9	6.6	8.1	8.9	11.3	10.8	11.3	8.1
NATG	35.6	35.6	36.2	32.4	30.4	33.4	32.4	27.8	30.3	30.4	30.0	30.7	32.0
OIL	1.1	1.6	2.9	3.5	4.1	3.9	3.4	4.9	1.2	1.0	0.5	0.2	2.4
SOLR	0.1	0.3	0.6	0.8	0.8	0.7	0.7	0.6	0.7	0.6	0.7	0.7	0.6
WIND	1.8	2.3	1.6	0.7	0.4	0.4	0.4	0.8	1.0	0.8	2.2	3.0	1.2
	Weighted Average Generator Price by Plant Type (PhP/MWh)												
BAT							2,979	2,684	2,127	2,049	1,743	1,837	2,237
BIOF	1,773	2,160	3,180	3,267	2,611	4,493	2,612	3,742	2,660	2,435	2,195	2,038	2,764
COAL	1,944	2,156	2,989	3,120	2,560	4,169	2,619	3,544	2,531	2,371	2,174	2,103	2,690
GEO	1,832	2,105	2,931	3,099	2,529	4,368	2,529	3,602	2,536	2,362	2,129	2,033	2,671
HYD	2,351	2,538	4,083	4,606	3,333	6,061	3,451	4,642	3,190	2,542	2,338	2,321	3,454
NATG	1,887	2,235	3,160	3,257	2,654	4,552	2,706	4,103	2,771	2,508	2,270	2,148	2,854
OIL	4,102	3,392	5,704	5,868	3,759	7,584	5,956	8,259	6,670	4,041	3,331	8,946	5,634
SOLR	2,510	2,767	3,346	3,651	2,998	5,110	3,477	4,216	2,947	2,685	2,329	2,139	3,181
WIND	1,087	1,751	2,468	2,388	2,529	5,358	2,048	2,768	2,702	2,001	2,028	1,896	2,419

Table 75. Generation Mix vs. Price – Visayas

Plant Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
	Generation Mix vs. Price - Visayas												
	Generation Mix (%)												
BIOF	2.2	3.0	2.4	2.0	0.5	0.1	0.1	0.1	0.2	1.6	2.3	2.3	1.4
COAL	32.5	33.0	33.1	33.1	36.8	38.4	38.7	36.2	39.2	40.1	39.8	39.9	36.8
GEO	57.2	55.4	52.9	52.2	50.5	48.5	50.1	49.1	50.0	47.6	48.1	49.1	50.8
HYD	0.2	0.2	0.2	0.1	0.2	0.4	0.7	0.7	0.7	0.9	0.7	0.7	0.5
OIL	3.8	3.3	4.9	4.9	5.0	6.6	4.2	5.8	2.6	2.7	1.8	1.0	3.9
SOLR	1.2	1.1	4.2	5.8	5.7	5.6	5.7	5.9	6.4	5.9	5.1	4.9	4.8
WIND	3.1	4.0	2.3	2.0	1.3	0.4	0.6	2.1	0.9	1.2	2.2	2.1	1.8
	Weighted Average Generator Price by Plant Type (PhP/MWh)												
BIOF	3,763	2,360	3,079	2,974	2,607	3,818	12,199	2,560	(568)	1,022	2,447	1,659	3,160
COAL	2,078	2,294	3,223	3,343	2,596	4,052	2,457	3,814	2,555	1,986	2,267	1,847	2,709
GEO	1,839	2,131	2,988	3,053	2,368	4,296	2,499	3,612	2,511	1,892	2,209	1,782	2,598
HYD	2,495	2,271	3,385	3,778	3,744	5,303	2,650	3,392	2,476	1,767	2,197	1,788	2,937
OIL	5,120	4,207	6,126	6,492	4,361	8,705	4,688	8,084	5,584	3,416	4,219	6,185	5,599
SOLR	3,787	2,943	2,670	3,324	2,466	4,370	2,981	3,814	2,499	1,702	2,087	1,552	2,850
WIND	1,855	2,380	3,496	3,238	3,283	4,913	2,262	2,740	2,530	1,542	2,285	1,660	2,682

Table 76. Year-on-Year Comparison, Generation Mix vs. Price – Luzon

	BAT	BIOF	COAL	GEO	HYD	NATG	OIL	SOLR	WIND
	Year-on-Year Comparison, Generation Mix vs. Price - Luzon								
	Generation Mix (%)								
2016	0.0	0.7	48.5	6.5	8.1	32.0	2.4	0.6	1.2
2015		0.3	48.4	6.8	8.3	33.3	1.7	0.1	1.0
Y-Y % Change		0.4	0.1	(0.4)	(0.2)	(1.3)	0.7	0.5	0.2
	GWAP (PhP/MWh)								
2016	2,237	2,764	2,690	2,671	3,454	2,854	5,634	3,181	2,419
2015		3,748	3,553	3,433	4,408	3,663	7,491	4,951	2,927
Y-Y % Change		(26.3)	(24.3)	(22.2)	(21.6)	(22.1)	(24.8)	(35.7)	(17.4)

Table 77. Year-on-Year Comparison, Generation Mix vs. Price – Visayas

	BIOF	COAL	GEO	HYD	OIL	SOLR	WIND
	Year-on-Year Comparison, Generation Mix vs. Price - Visayas						
	Generation Mix (%)						
2016	1.4	36.8	50.8	0.5	3.9	4.8	1.8
2015	1.1	36.6	55.7	0.2	4.2	0.7	1.5
Y-Y % Change	0.3	0.2	(4.9)	0.2	(0.3)	4.1	0.3
	GWAP (PhP/MWh)						
2016	3,160	2,709	2,598	2,937	5,599	2,850	2,682
2015	7,232	3,684	3,494	6,742	7,277	5,651	4,455
Y-Y % Change	(56.3)	(26.5)	(25.6)	(56.4)	(23.1)	(49.6)	(39.8)

XVII. SPOT MARKET EXPOSURE[46]

A. Generator Spot Market Exposure[47]

Significant increases in spot market exposure were observed throughout the year, as both the Luzon and Visayas regions obtained higher spot exposure levels when compared to the previous year.

The spot market exposure of generators accounted for 16.7 percent of the total energy injected during the year, notably higher than previous year's 12 percent. The same was also higher than the generator spot exposure posted in 2014 at 11.2 percent. Meanwhile, the remaining 83.3 percent were metered quantities covered by bilateral contracts. This was correspondingly lower than those posted in the two previous billing years at 88 percent and 88.8 percent, respectively. Higher monthly spot exposure levels were observed from August to December 2016, the highest of which was posted at 22.4 percent in December, while spot exposure levels were relatively lower from January to July, the lowest being at 11.6 percent during the February billing month.

Year-on-year comparison also showed a remarkable increase of about 52 percent in terms of generator spot transaction volume, from last year's total spot quantity of 7,906,655MWh to 12,018,699MWh this year. The largest monthly spot volume was posted in November and December at 1,294,986MWh and 1,280,374MWh, respectively. On the other hand, system-wide generator metered quantities increased by about 9 percent, from a total of 65,932,001MWh in the previous year to 71,836,805MWh. Total generator bilateral contract quantities also increased by 3.1 percent from 58,025,347MWh to 59,818,106MWh.

Luzon mirrored the trend system-wide, posting its generator spot exposure at 14 percent, a significant increase from the 9.8 percent spot exposure in 2015. On the other hand, bilateral contracts covered the remaining 86 percent of the total metered quantities this year, a decline from last year's 90.2 percent. The highest monthly spot exposure in Luzon was recorded in November and December at 19.4 percent and 19.9 percent, while the lowest was posted in February at 7.9 percent. Monthly spot exposure levels were likewise high in Luzon during the August to October billing months at 17.5 percent, 16.2 percent and 18.9 percent, respectively.

Spot market quantities of Luzon generators increased by 54.9 percent from 5,487,416MWh in 2015 to 8,498,839MWh this year. Bilateral quantities similarly increased by 4.3 percent from a total of 50,110,986MWh to 52,280,486MWh. The total energy injected in Luzon increased by 9.3 percent from 55,598,402MWh to 60,779,325MWh in metered quantities.

Meanwhile Visayas obtained the highest increase in generator spot market exposure at 31.8 percent from last year's 23.4 percent. The monthly level of spot exposure in the region was likewise observed to be consistently high and maintained within the close range of 28.3 percent (posted in June) to 34.6 percent (in December). On the other hand, bilateral contract quantities declined from 76.6 percent in the previous year to 68.2 percent this year.

Generator metered quantities in the Visayas increased by about 7 percent from a total of 10,333,599MWh in 2015 to 11,057,480MWh. However, bilateral contract quantities declined

[46] 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.
[47] 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.

by about 4.8 percent from 7,914,360MWh to 7,537,620MWh. Spot market quantities in the region increased considerably by 45.5 percent from 2,419,239MWh to 3,519,860MWh.

Figure 63. Generator's Spot Market Exposure – System

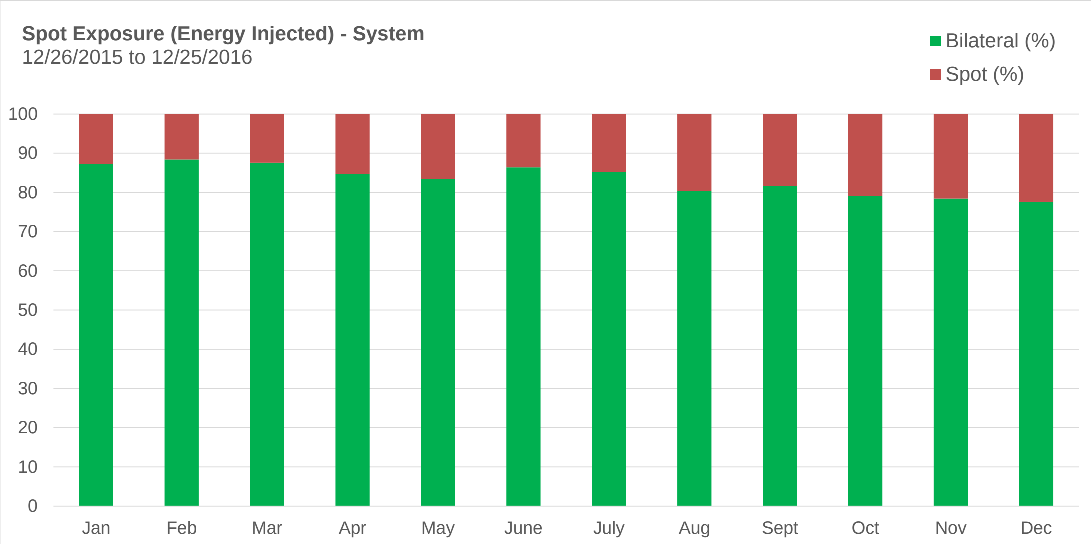


Table 78. Generators' Spot Market Exposure – System, 2016

	Generators' Spot Exposure by Billing Month - 2016												
	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
Metered Qty (MWh)	5,334,071	5,557,581	5,485,909	6,303,596	6,458,519	6,496,054	6,055,337	6,226,656	6,220,644	5,974,212	6,007,144	5,717,083	71,836,805
Bilateral Qty (MWh)	4,654,523	4,913,271	4,804,539	5,335,737	5,384,734	5,611,987	5,159,456	5,001,738	5,077,445	4,725,809	4,712,158	4,436,709	59,818,106
Spot Market Qty (MWh)	679,549	644,309	681,370	967,858	1,073,785	884,067	895,881	1,224,918	1,143,199	1,248,403	1,294,986	1,280,374	12,018,699
Bilateral Qty (%)	87.3	88.4	87.6	84.6	83.4	86.4	85.2	80.3	81.6	79.1	78.4	77.6	83.3
Spot Market (%)	12.7	11.6	12.4	15.4	16.6	13.6	14.8	19.7	18.4	20.9	21.6	22.4	16.7

Table 79. Year-on-Year Comparison of Generators' Spot Market Exposure

	Year-on-Year Comparison of Generator's Monthly Spot Exposure (%) - System												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Total
2016	12.7	11.6	12.4	15.4	16.6	13.6	14.8	19.7	18.4	20.9	21.6	22.4	16.7
2015	9.6	11.1	13.5	13.6	11.8	12.2	13.4	11.7	12.4	11.7	11.1	11.6	12.0
(%) Change	3.1	0.5	(1.1)	1.7	4.8	1.4	1.4	8.0	6.0	9.2	10.5	10.8	4.7

Figure 64. Generator's Spot Market Exposure – Luzon

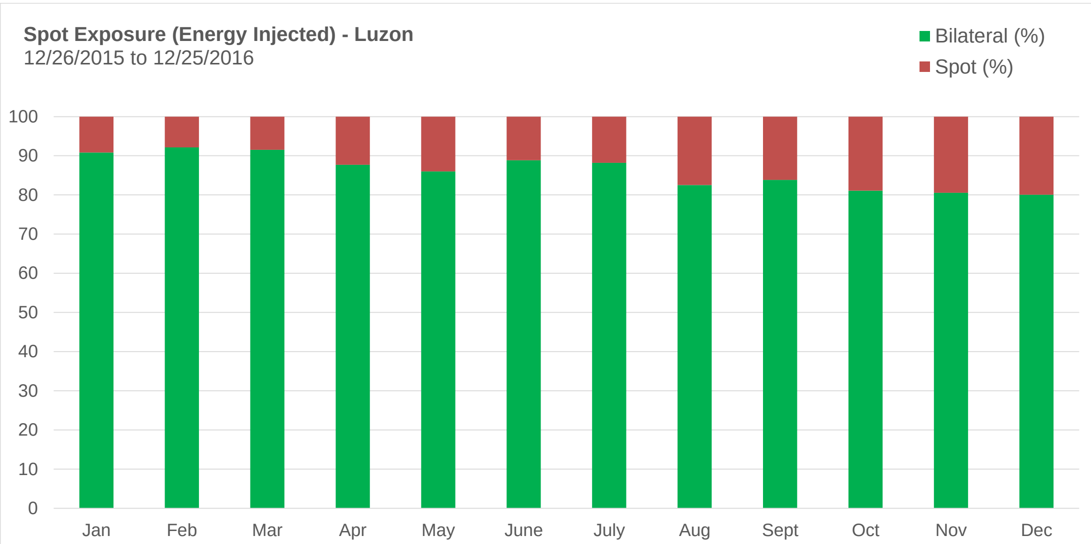


Table 80. Generators' Spot Market Exposure – Luzon

	Generators' Spot Exposure by Billing Month - Luzon, 2016												
	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
Metered Qty (MWh)	4,456,199	4,664,171	4,602,012	5,346,982	5,502,444	5,568,264	5,143,477	5,295,761	5,281,699	5,073,136	5,091,144	4,754,035	60,779,325
Bilateral Qty (MWh)	4,047,652	4,296,704	4,211,703	4,688,479	4,731,220	4,947,086	4,537,108	4,370,631	4,428,406	4,113,387	4,101,570	3,806,540	52,280,486
Spot Market Qty (MWh)	408,548	367,467	390,309	658,503	771,225	621,178	606,369	925,130	853,292	959,749	989,573	947,496	8,498,839
Bilateral Qty (%)	90.8	92.1	91.5	87.7	86.0	88.8	88.2	82.5	83.8	81.1	80.6	80.1	86.0
Spot Market (%)	9.2	7.9	8.5	12.3	14.0	11.2	11.8	17.5	16.2	18.9	19.4	19.9	14.0

Table 81. Year-on-Year Comparison of Generators' Spot Market Exposure - Luzon

	Year-on-Year Comparison of Generator's Monthly Spot Exposure (%) - Luzon												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Total
2016	9.2	7.9	8.5	12.3	14.0	11.2	11.8	17.5	16.2	18.9	19.4	19.9	14.0
2015	7.6	8.0	11.2	11.9	9.9	10.3	11.5	10.2	10.7	9.3	8.5	8.9	9.9
(%) Change	1.6	(0.2)	(2.7)	0.4	4.1	0.8	0.3	7.3	5.5	9.7	11.0	11.1	4.1

Figure 65. Generators Spot Market Exposure – Visayas

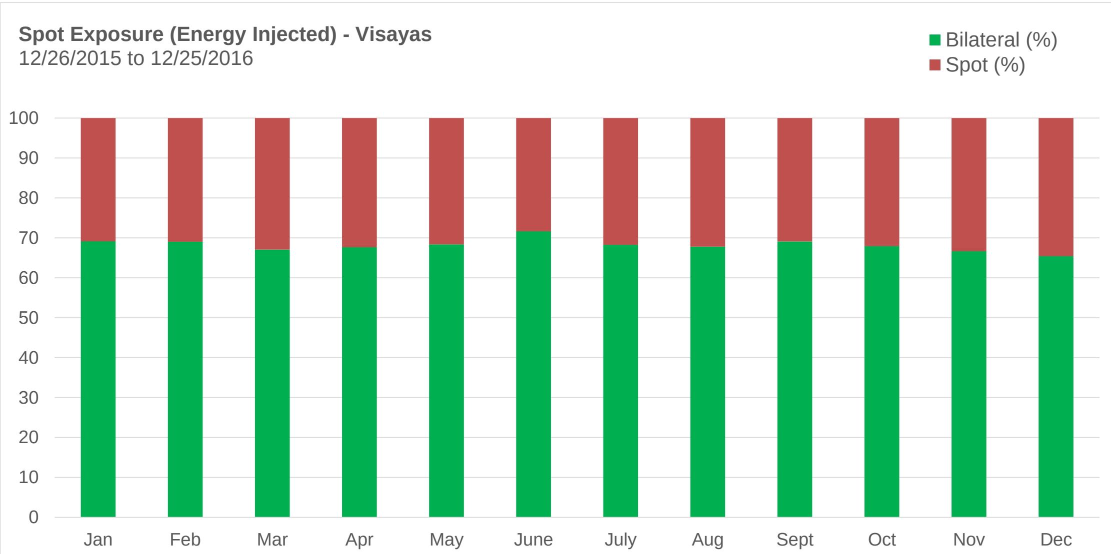


Table 82. Generators' Spot Market Exposure – Visayas

	Generators' Spot Exposure by Billing Month - Visayas, 2016												
	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
Metered Qty (MWh)	877,872	893,410	883,897	956,613	956,075	927,790	911,859	930,895	938,946	901,075	916,000	963,047	11,057,480
Bilateral Qty (MWh)	606,871	616,567	592,836	647,258	653,514	664,901	622,348	631,107	649,038	612,422	610,588	630,169	7,537,620
Spot Market Qty (MWh)	271,001	276,843	291,061	309,355	302,561	262,889	289,512	299,788	289,907	288,653	305,413	332,878	3,519,860
Bilateral Qty (%)	69.1	69.0	67.1	67.7	68.4	71.7	68.3	67.8	69.1	68.0	66.7	65.4	68.2
Spot Market (%)	30.9	31.0	32.9	32.3	31.6	28.3	31.7	32.2	30.9	32.0	33.3	34.6	31.8

Table 83. Year-on-Year Comparison of Generators' Spot Market Exposure - Visayas

	Year-on-Year Comparison of Generator's Monthly Spot Exposure (%) - Visayas												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Total
2016	30.9	31.0	32.9	32.3	31.6	28.3	31.7	32.2	30.9	32.0	33.3	34.6	31.8
2015	19.5	25.9	25.9	22.8	22.2	23.1	23.3	20.3	22.2	24.5	25.6	25.6	23.4
(%) Change	11.4	5.1	7.0	9.5	9.4	5.3	8.4	11.9	8.7	7.5	7.8	9.0	8.4

B. Impact of Preferential and Non-Scheduled Generation to Spot Exposure

As discussed in the previous section, generator spot exposure levels were generally higher this year when compared with the previous year. This trend is in part influenced by the contribution of preferential and non-scheduled generation, which metered quantities were observed to be mostly exposed to the spot market.

A total of 2,750,026MWh metered quantities were attributed to preferential and non-scheduled generation, equivalent to about 3.6 percent of the total volume of energy injected this year. Of this, 98.4 percent were spot quantities while only 1.6 percent were contracted.

Consequently, the spot market exposure of preferential and non-scheduled generating units was posted at 21 percent, which was 2,529,828MWh out of the total spot quantity of 9,488,871MWh during the year. The remaining 79 percent which totalled 12,018,699MWh was on account of the generator spot volume of scheduled generating units. The February billing month recorded the highest spot market exposure of preferential and non-scheduled generation, accounting for as much as 35.5 percent of the total spot exposure during the month. This followed the low spot exposure of scheduled generation in February, which was its lowest during the year. For the rest of the billing months, preferential and non-scheduled generation posted its contribution to the total generator spot exposure within the close range of 16.1 percent to 26.5 percent.

Figure 66. Spot Market Exposure by Category – System

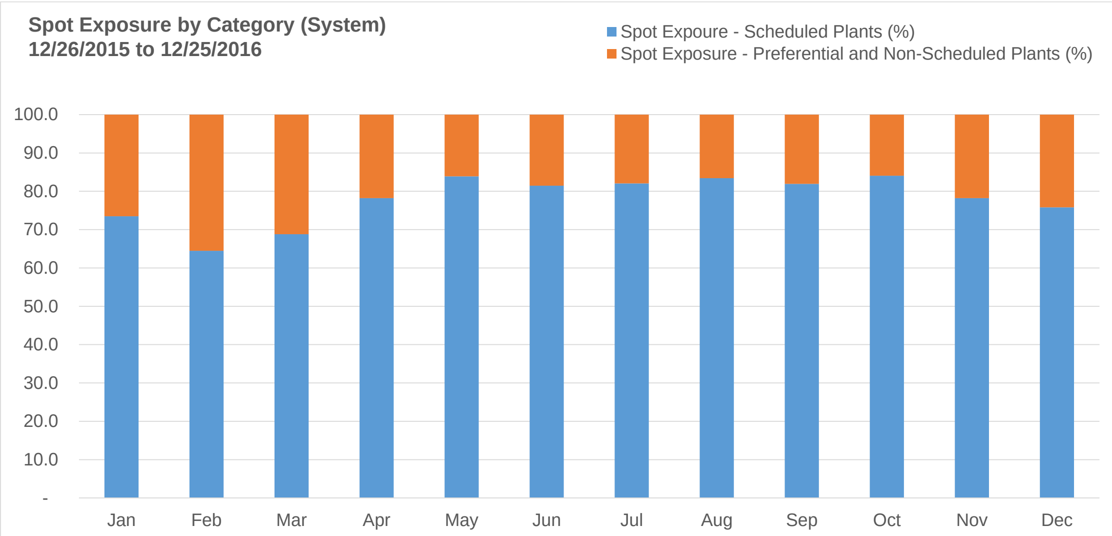


Table 84. Spot Market Exposure by Category

Spot Market Quantity (MWh) by Category - System, 2016													
	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
	Scheduled Generating Plants												
Metered Quantity	5,152,272	5,326,743	5,272,084	6,091,775	6,284,380	6,328,805	5,890,661	6,019,368	6,006,208	5,770,404	5,720,311	5,403,769	69,266,779
Bilateral Quantity	4,652,914	4,911,161	4,803,345	5,334,622	5,383,626	5,608,534	5,155,415	4,997,658	5,069,653	4,720,800	4,707,359	4,432,820	59,777,908
Spot Quantity	499,358	415,581	468,739	757,153	900,753	720,271	735,245	1,021,710	936,555	1,049,604	1,012,952	970,950	9,488,871
	Preferential and Non-Scheduled Generating Plants												
Metered Quantity	181,800	230,838	213,825	211,820	174,139	167,249	164,676	207,288	214,436	203,808	286,833	313,314	2,570,026
Bilateral Quantity	1,609	2,110	1,194	1,116	1,107	3,453	4,040	4,080	7,792	5,009	4,799	3,890	40,198
Spot Quantity	180,191	228,728	212,631	210,705	173,032	163,796	160,635	203,208	206,644	198,799	282,035	309,424	2,529,828

Table 85. Spot Market Exposure (%) by Category

Spot Exposure (%) by Category - 2016													
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Scheduled Plants	73.5	64.5	68.8	78.2	83.9	81.5	82.1	83.4	81.9	84.1	78.2	75.8	79.0
Preferential and Non-Scheduled Plants	26.5	35.5	31.2	21.8	16.1	18.5	17.9	16.6	18.1	15.9	21.8	24.2	21.0

Table 86. Year-on-Year Comparison of Spot Market Exposure – Preferential and Non-Scheduled Plants

Year-on-Year Comparison of Spot Market Exposure - Preferential and Non-Scheduled Plants													
	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Avg
2016	26.5	35.5	31.2	21.8	16.1	18.5	17.9	16.6	18.1	15.9	21.8	24.2	21.0
2015	21.2	16.3	10.7	10.6	5.3	4.4	11.3	10.5	10.9	21.9	29.2	34.8	15.0

C. Customer Spot Market Exposure[48]

The spot market exposure of customers accounted for about 14.8 percent of the total energy withdrawn during the year, while about 85.2 percent was covered by bilateral contracts. Corresponding to the trend in the spot exposure of generators, customers' monthly spot exposure levels were likewise higher during the second half of the year, particularly from August to December. The November and December billing months recorded the highest spot exposure levels at 19.8 percent and 20.7 percent, respectively. Meanwhile, the lowest customer spot exposure was posted in February at 9.5 percent.

When compared with the previous year, customers' spot exposure increased from 9.8 percent in the previous year, while in contrast, the percentage of bilateral contract quantities declined from 90.2 percent.

In terms of the volume of customers' spot transactions system-wide, an increase of 64.4 percent was observed from the total spot quantity of 6,326,909MWh in 2015 to 10,399,448MWh this year. The largest spot volume was recorded in December at 1,156,831 MWh. Spot volumes were noticeably larger from August to December, translating to higher spot exposure levels during these months.

Figure 67. Customers' Spot Market Exposure – System

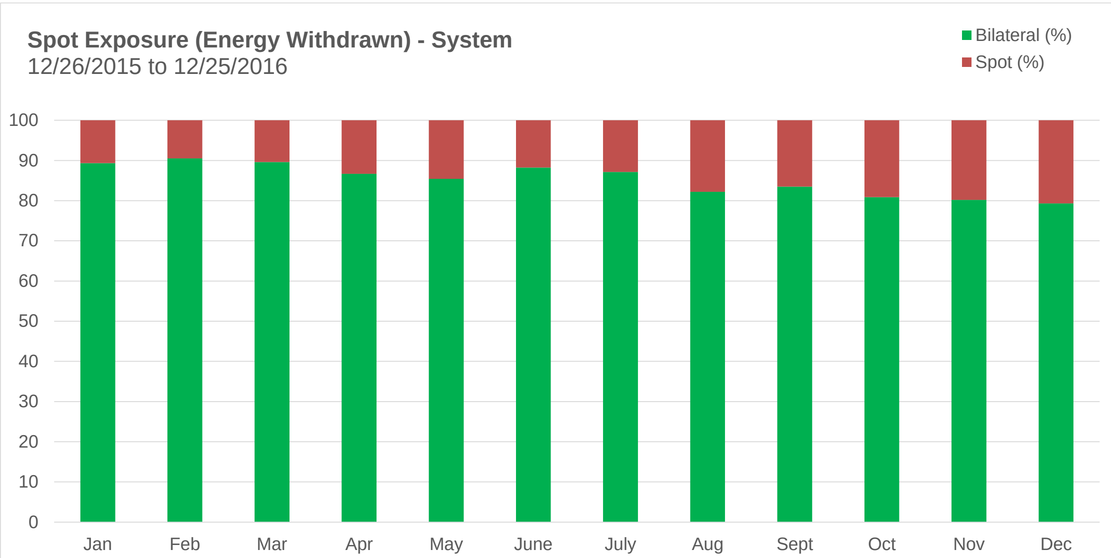


Table 87. Customers' Spot Market Exposure – System

	Customers' Spot Exposure by Billing Month - 2016												
	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
Metered Qty (MWh)	5,209,601	5,427,577	5,360,989	6,156,941	6,302,769	6,359,194	5,921,505	6,084,216	6,081,227	5,842,645	5,877,349	5,593,540	70,217,554
Bilateral Qty (MWh)	4,654,523	4,913,271	4,804,539	5,335,737	5,384,734	5,611,987	5,159,456	5,001,738	5,077,445	4,725,809	4,712,158	4,436,709	59,818,106
Spot Market Qty (MWh)	555,079	514,305	556,450	821,204	918,035	747,207	762,049	1,082,479	1,003,782	1,116,836	1,165,191	1,156,831	10,399,448
Bilateral Qty (%)	89.3	90.5	89.6	86.7	85.4	88.2	87.1	82.2	83.5	80.9	80.2	79.3	85.2
Spot Market (%)	10.7	9.5	10.4	13.3	14.6	11.8	12.9	17.8	16.5	19.1	19.8	20.7	14.8

Table 88. Year-on-Year Comparison of Customers' Spot Market Exposure – System

	Year-on-Year Comparison of Customers' Monthly Spot Exposure (%) - System												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Total
2016	10.7	9.5	10.4	13.3	14.6	11.8	12.9	17.8	16.5	19.1	19.8	20.7	14.8
2015	7.3	8.6	11.2	11.6	9.6	10.0	11.2	9.5	10.5	9.6	9.0	9.6	9.8
(%) Change	3.4	0.9	(0.8)	1.8	5.0	1.8	1.6	8.3	6.0	9.5	10.8	11.1	5.0

[48] The customer's spot exposure is equivalent to the percentage of energy withdrawn not covered by bilateral contracts. Customer MQ includes Kalayaan PSPP (pumping) and generators' station use.

In the Luzon region, 14.4 percent of the total energy requirement of Luzon customers was procured from the spot market while the majority or 85.6 percent was covered by bilateral contracts. Of the latter, 85.2 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 November and December at 20.1 percent and 21.6 percent, respectively. Customer spot exposure levels in August, September and October were likewise relatively higher at 17.7 percent, 16.4 percent and 19.2 percent. On the other hand, spot exposure among customers was recorded low in February at 8.7 percent.

When compared with 2015, increase in the spot exposure of Luzon generators was notable, from only 9.8 percent. Correspondingly, the percentage of customer bilateral contract quantities from the total metered quantities in the previous year declined from 90.2 percent, 89.9 percent of which were bilateral quantities within the region while 0.4 percent were bilateral quantities with Visayas generators.

The volume of spot quantity increased considerably this year by about 59.8 percent from a total of 5,425,533MWh to 8,669,724MWh, mostly driven by the large spot quantities incurred from August to December. The November and December billing months demonstrated the largest spot quantity at 1,013,512 MWh and 1,030,524 MWh.

Figure 68. Customers' Spot Market Exposure – Luzon

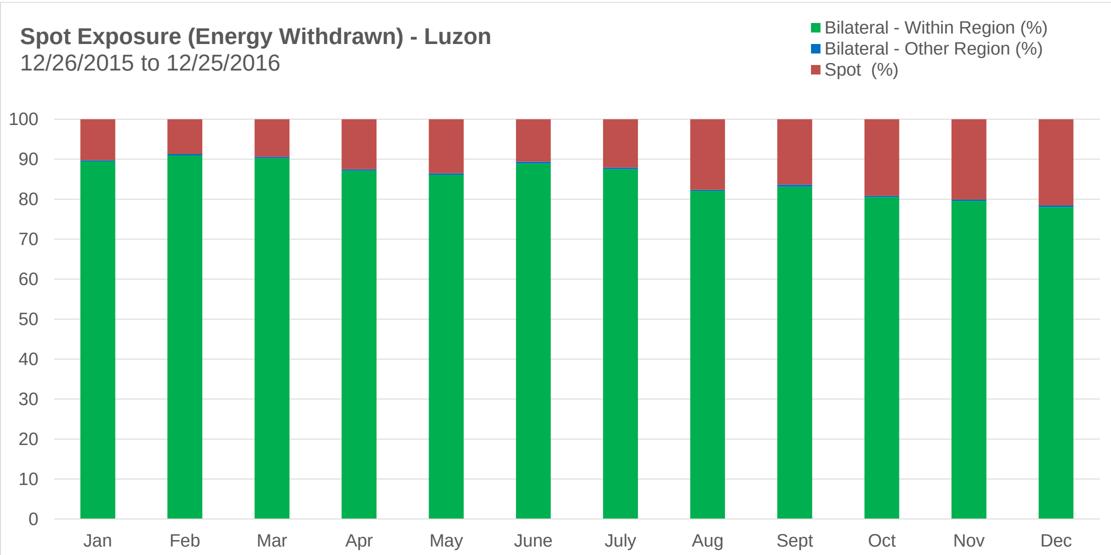


Table 89. Customers' Spot Market Exposure – Luzon

	Customers' Spot Exposure by Billing Month - Luzon, 2016												
	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
Metered Qty (MWh)	4,442,439	4,642,298	4,590,764	5,286,644	5,402,222	5,474,603	5,088,906	5,219,781	5,223,246	5,008,236	5,043,885	4,779,155	60,202,178
Bilateral Qty-Within Region (MWh)	3,973,058	4,219,890	4,142,282	4,604,444	4,648,983	4,864,428	4,451,674	4,282,511	4,341,058	4,033,156	4,012,123	3,727,620	51,301,226
Bilateral Qty-Other Region (MWh)	13,468	18,111	15,215	18,935	22,766	27,247	20,485	14,470	27,223	14,048	18,249	21,010	231,228
Spot Market Qty (MWh)	455,913	404,297	433,267	663,265	730,473	582,928	616,747	922,800	854,965	961,032	1,013,512	1,030,524	8,669,724
Bilateral Qty-Within Region (%)	89.4	90.9	90.2	87.1	86.1	88.9	87.5	82.0	83.1	80.5	79.5	78.0	85.2
Bilateral Qty-Other Region (%)	0.3	0.4	0.3	0.4	0.4	0.5	0.4	0.3	0.5	0.3	0.4	0.4	0.4
Spot Market (%)	10.3	8.7	9.4	12.5	13.5	10.6	12.1	17.7	16.4	19.2	20.1	21.6	14.4

Table 90. Year-on-Year Comparison of Customers' Spot Market Exposure – Luzon

	Year-on-Year Comparison of Customers' Monthly Spot Exposure (%) - Luzon												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Total
2016	10.3	8.7	9.4	12.5	13.5	10.6	12.1	17.7	16.4	19.2	20.1	21.6	14.4
2015	8.0	8.7	10.8	12.3	9.5	9.8	12.2	10.0	10.3	8.9	7.7	9.2	9.8
(%) Change	2.3	0.0	(1.4)	0.2	4.0	0.8	(0.1)	7.7	6.0	10.3	12.4	12.3	4.6

Customers' spot exposure level in the Visayas accounted for 17.3 percent of the total energy withdrawn during the year. On the other hand, the remaining 82.7 percent was attributed to bilateral contract quantities, 73 percent of which were quantities covered by bilateral contracts within the region while the rest of the 9.8 percent was attributable to bilateral contract quantities with Luzon generators. Year-on-year comparison of customer spot exposure levels in the region showed an increase from last year's spot exposure of 10 percent. Accordingly, decline in the percentage of bilateral quantities within the region was observed from last year's 85.1 percent, while bilateral quantities with Luzon generators increased from only 4.9 percent in 2015.

Monthly spot exposure levels were higher from April to November, distributed closely with the range of 17.3 percent (September) to 20.8 percent (May). Conversely, spot exposure levels were relatively lower from January to March and December within the range of 14 percent (February) to 16 percent (March).

Visayas customers increased their total energy withdrawn by 10.7 percent from total metered quantities of 9,045,903MWh in the previous year to 10,015,376MWh. Meanwhile, bilateral quantities within Visayas declined by 5.1 percent from 7,701,398MWh to 7,306,392MWh. In contrast, customer bilateral quantities with generators from Luzon increased by an exceptional 121 percent from 443,129MWh to 979,261MWh. Customer spot quantities in the region likewise increased by 91.9 percent from a total of 901,376MWh to 1,729,724MWh.

Figure 69. Customers' Spot Market Exposure – Visayas

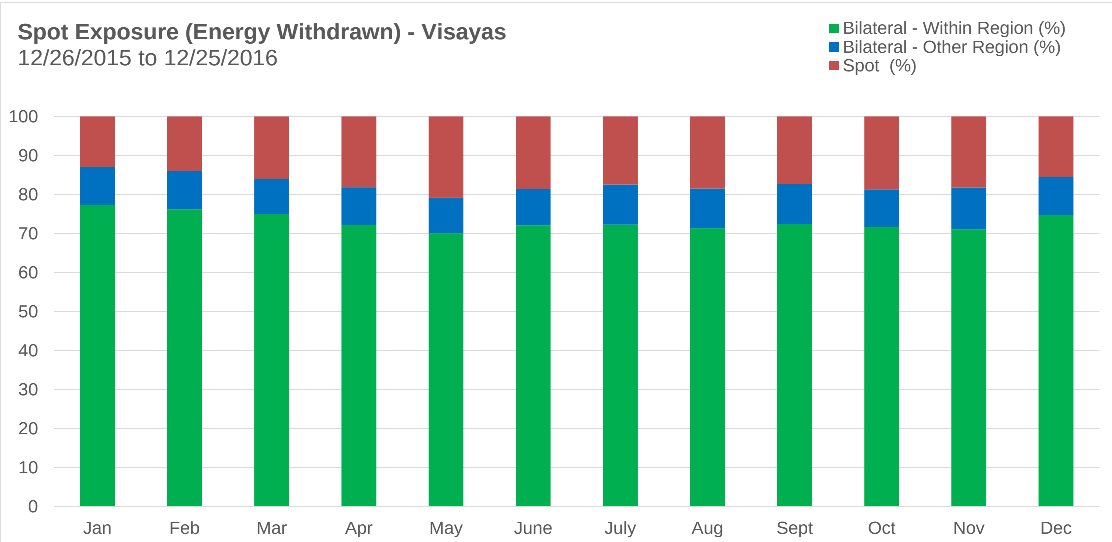


Table 91. Customers' Spot Market Exposure – Visayas

	Customers' Spot Exposure by Billing Month - Visayas, 2016												
	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
Metered Qty (MWh)	767,163	785,279	770,225	870,297	900,547	884,591	832,599	864,435	857,981	834,410	833,465	814,385	10,015,376
Bilateral Qty-Within Region (MWh)	593,403	598,456	577,621	628,323	630,748	637,654	601,863	616,637	621,816	598,374	592,339	609,159	7,306,392
Bilateral Qty-Other Region (MWh)	74,594	76,815	69,421	84,035	82,237	82,658	85,435	88,119	87,349	80,231	89,447	78,920	979,261
Spot Market Qty (MWh)	99,166	110,008	123,183	157,939	187,562	164,279	145,302	159,679	148,817	155,805	151,679	126,306	1,729,724
Bilateral Qty-Within Region (%)	77.4	76.2	75.0	72.2	70.0	72.1	72.3	71.3	72.5	71.7	71.1	74.8	73.0
Bilateral Qty-Other Region (%)	9.7	9.8	9.0	9.7	9.1	9.3	10.3	10.2	10.2	9.6	10.7	9.7	9.8
Spot Market (%)	12.9	14.0	16.0	18.1	20.8	18.6	17.5	18.5	17.3	18.7	18.2	15.5	17.3

Table 92. Year-on-Year Comparison of Customers' Spot Market Exposure – Visayas

	Year-on-Year Comparison of Customers' Monthly Spot Exposure (%) - Visayas												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Total
2016	12.9	14.0	16.0	18.1	20.8	18.6	17.5	18.5	17.3	18.7	18.2	15.5	17.3
2015	3.5	8.2	13.8	6.9	10.1	10.9	5.2	6.3	11.3	14.0	16.8	11.6	10.0
(%) Change	9.4	5.8	2.2	11.2	10.7	7.6	12.3	12.2	6.1	4.7	1.4	4.0	7.3

XVIII. 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.

A. Market Share[49]

1. By Major Participant Group

The share of the four largest groups in terms of registered capacity continued to dominate the market system-wide throughout year 2016. SMC, FGC, AP and PSALM took a combined market share averaging at 62.8 percent in 2016. With the exception of FGC, all three groups registered lower market shares this year as the number of new market players increased.

SMC's share of the market remained the biggest averaging at 19 percent, though lower than last year's 20.3 percent. SMC was followed by FGC, with its average market share growing to 16.3 percent from 15.1 percent in 2015. AP and PSALM were in the third and fourth spots, with shares of 14.9 percent and 12.6 percent, both of which were decreases from previous year's 15.8 percent and 13.7 percent, respectively. SMPC, GBPC, MPPCL and GMCP distantly followed with respective shares of 5.4 percent, 4.4 percent, 3.7 percent and 3.5 percent.

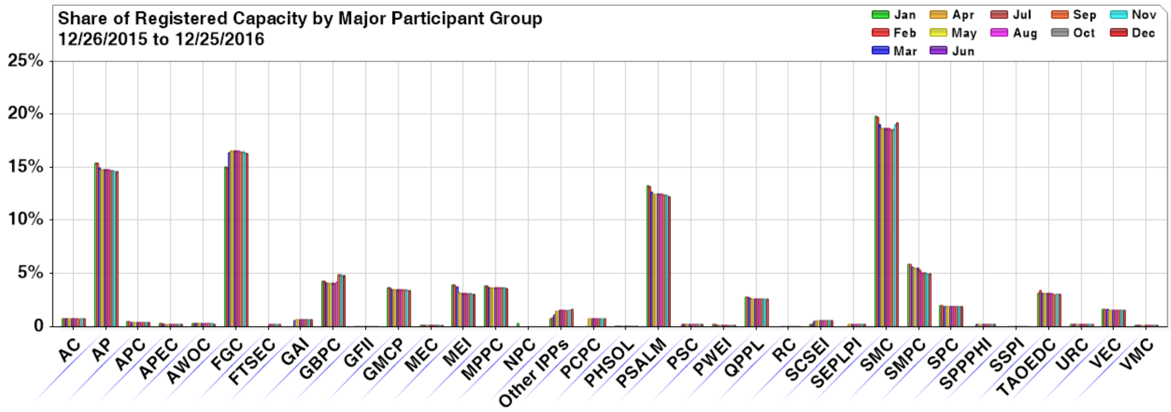
As shown in the Figure below, the market shares of each of the dominant groups, except for FGC steadily decreased beginning March with the entry of new players in the market, majority of which were solar plants. FGC's share of the market rose from 15 percent in February to about 16.6 percent beginning March. Said increase is due to the WESM registration of the 414 MW natural gas plant San Gabriel NGPP effective 02 March. Meanwhile, SMC recovered from its slightly declining market share with the registration effective 04 November of its 150-MW coal plant under SMC Consolidated Power Corporation. Consequently, SMC's market share which was posted at about 19 percent at the beginning of the year, and declined to about 18.7 percent from March to October, grew back to about 19.2 percent by year-end. Similarly, GBPC's market share increased from an average of about 4.2 percent to 4.3 percent in August and a firm 4.9 percent beginning September with the entry of its additional 150-MW coal unit under Panay Energy Development Corporation effective 19 August.

Other relevant changes which were observed during the year are as follows: the cessation from WESM membership of the National Power Corporation (NPC) effective 25 September in line with the transfer of ownership of Power Barges 101, 102 and 103 under the portfolio of TAOEDC; and, the de-registration of the 100-MW oil based plant Millennium GTPP from the WESM under the portfolio of MEI effective 1 April 2016.

[49] 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 Annual Report, calculation of system-wide market share was based on three major groupings: (i) by major participant group; (ii) by trading participants; and (iii) by generating plants.

Grouping by major participant group is provided for in detail under Appendix C of this Report.

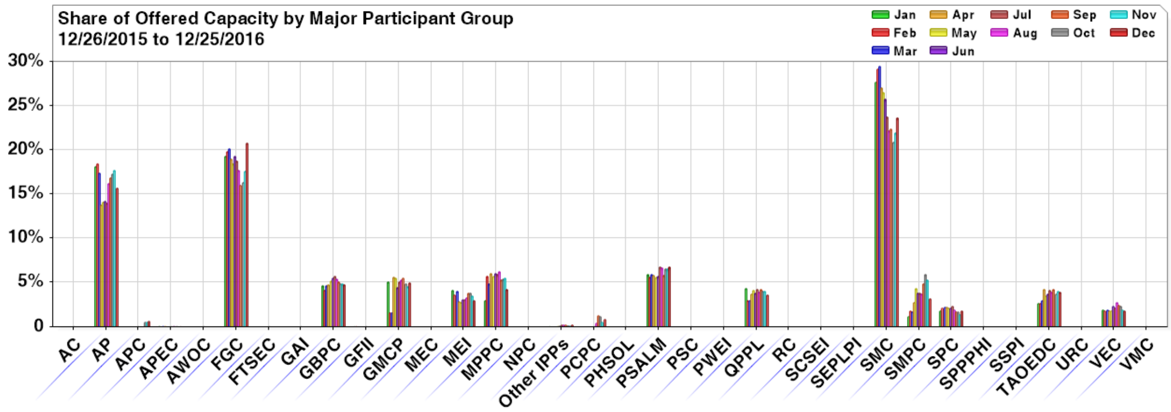
Figure 70. Market Share by Major Participant Group based on Registered Capacity



SMC's system-wide share of the market based on offered capacity was the largest, averaging at 25 percent this year, followed by FGC with 18.6 percent and AP, 16.2 percent. PSALM distantly followed at 6.2 percent and MPPCL at 5.3 percent. Drop in the offered capacity share of SMC was observed during the second half of the year, following the lower offered capacity shares of Ilijan NGPP in August and September, and Sual CFTPP from September to December.

Respective shares in the offered capacity of the most dominant groups were generally lower in 2016 when compared to the previous year, except for AP, which market share increased from last year's 15.2 percent. SMC accounted for about 23.4 percent of the offered capacity market in 2015, while 20.5 percent and 6.3 percent were attributed to FGC and PSALM.

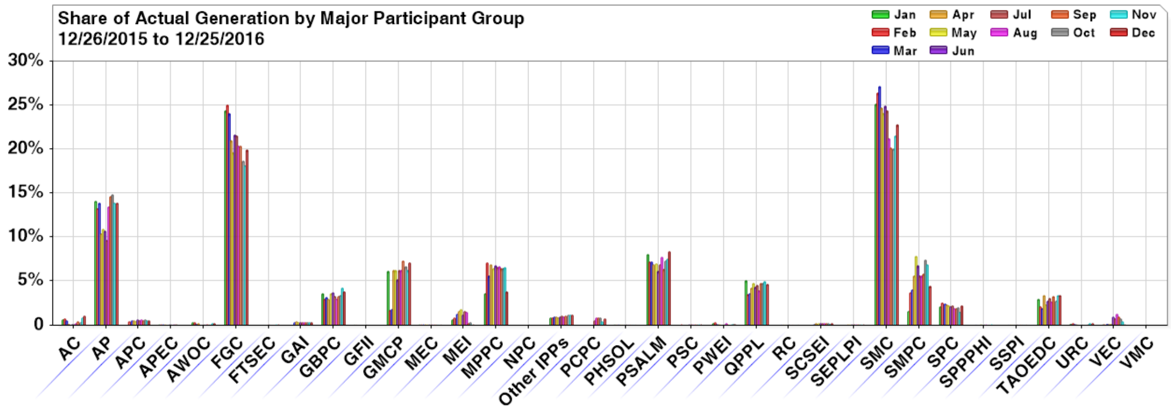
Figure 71. Market Share by Major Participant Group based on Offered Capacity



In terms of actual generation based on metered quantities, the market was also dominated by the four major groups with a combined share of about 64.6 percent in 2016. However, this share was considerably lower in comparison with 2015, influenced by the substantial number of new players which have successfully entered the market during the year. Nevertheless, market shares based on actual generation indicate that majority of the demand requirement in year 2016 was still supplied by SMC, FGC, AP and PSALM, with market shares of 23.5 percent, 21.1 percent, 12.7 percent and 7.2 percent, all lower than last year's 24 percent, 22.9 percent, 14 percent, and 7.6 percent, respectively.

Lower market share levels particularly during the second half of the year was incurred by SMC, attributed to the lower shares in actual generation of Ilijan NGPP from August to September, and Sual CFTPP from September to December due to high outage capacity.

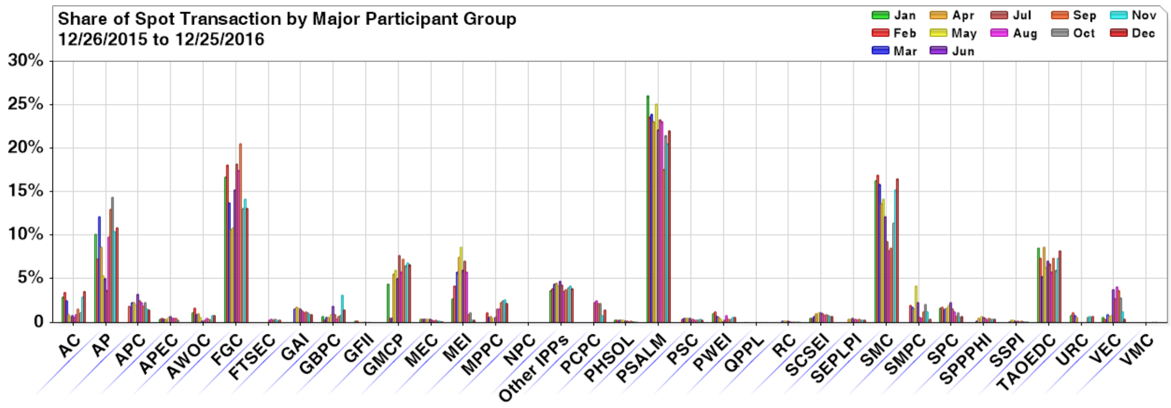
Figure 72. Market Share by Major Participant Group based on Actual Generation



PSALM continued to hold the top place in terms of system-wide market share based on spot transaction at an average of 22.5 percent. FGC, SMC and AP came next at 15.2 percent, 13.1 percent and 9.5 percent, respectively. TAOEDC placed fifth with 7.1 percent followed by GMCP at 5.5 percent. Except for FGC, the three other dominant groups-PSALM, SMC and AP all posted lower market shares this year compared with last year's 26.5 percent, 19 percent, and 12 percent. Meanwhile, TAOEDC and GMCP both obtained higher market shares based on spot transaction when compared with previous year's 3.9 percent and 3.2 percent.

Looking at Figure 73, PSALM's share of the market went on decreasing trend, while drop in the shares of SMC were observed during the third quarter. FGC similarly incurred lower market shares in the second and last quarter of the year.

Figure 73. Market Share by Major Participant Group based on Spot Transaction

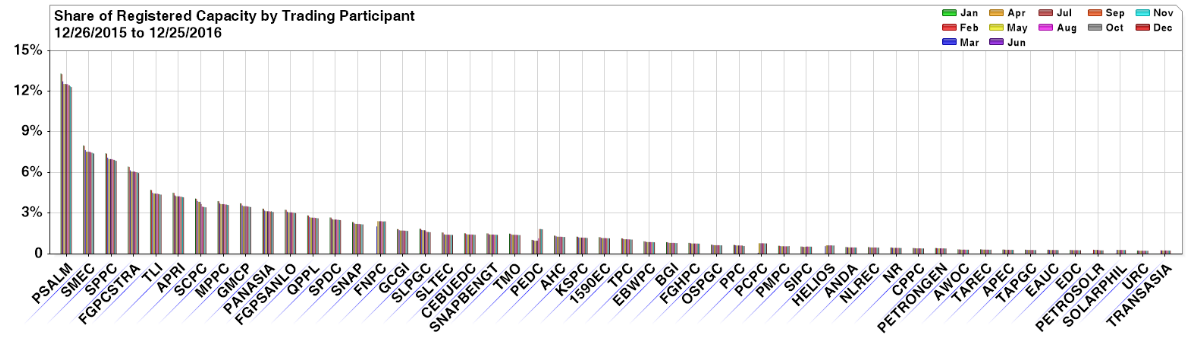


2. By Trading Participant

Market shares based on registered capacity by trading participant denotes that PSALM had the biggest share system-wide at an average of 12.6 percent. San Miguel Energy Corporation (SMEC) and South Premiere Power Corporation (SPPC), both under the SMC portfolio, secured the second and third spots with 7.6 percent and 7 percent. FGP Corporation (FGPCSTRA) followed averaging at 6.1 percent while trading participants Therma Luzon Inc. (TLI) and AP Renewables Inc. (APRI) under the AP portfolio recorded shares averaging at 4.5 percent and 4.3 percent, respectively.

Note that SMEC is the registered trader for Sual CFTPP while SPPC trades for Ilijan NGPP. FGPCSTRA and TLI, on the other hand, are the trading participants for Sta. Rita NGPP and Pagbilao CFTPP respectively, while APRI trades for Makban GPP and Tiwi GPP.

Figure 74. Market Share by Trading Participant based on Registered Capacity

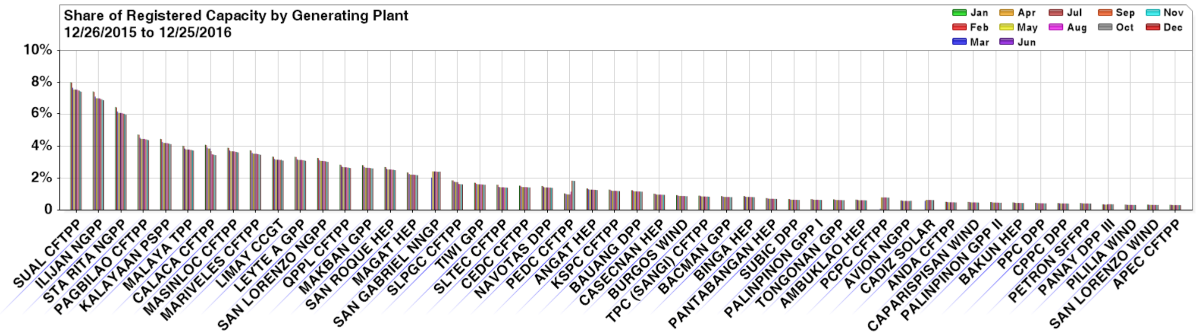


3. By Generating Plant

Generating plants owned or controlled by the top four major groups likewise dominated the system-wide market share by generating plant based on registered capacity, though shares notably decreased beginning the March billing month as illustrated in Figure 71 below.

SMC's Sual CFTPP and Ilijan NGPP held the first and second spots at about 7.6 percent and 7 percent during the year. FGC's Sta. Rita NGPP came next at 6.1 percent followed by AP's Pagbilao CFTPP at 4.5 percent. PSALM's Kalayaan PSPP and Malaya TPP were in fifth and sixth places at 4.2 percent and 3.8 percent.

Figure 75. Market Share by Generating Plant based on Registered Capacity



B. Herfindahl-Hirschman Index (HHI)[50]

The market was moderately concentrated as shown in the resulting HHIs in Figure 76, with indications that market concentration levels generally improved beginning the second quarter of the year influenced in part by the entry of a substantial number of new smaller players and groups in year 2016. Notwithstanding, fluctuations in monthly HHI levels were

[50] 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.

more evident in the HHI calculations based on offered capacity, actual generation and spot transaction, which could be influenced by the varying conditions of supply availability throughout the year.

It is noteworthy that HHI values by major participant group were considerably higher based on offered capacity and actual generation, and were highest during the first quarter of the year. Note that resulting HHI values based on offered capacity during the February and March billing months almost hit the concentrated mark. On the other hand, HHI values were observed to be lower and more stable based on WESM registered capacity.

Monthly HHI results by trading participant signalled a not concentrated market, though higher and more fluctuating HHI values were observed in the HHI calculations based on actual generation and spot transaction.

By generating plant, the resulting HHI likewise indicated a not concentrated market throughout the billing year 2016.

Figure 76. HHI by Major Participant Group – System

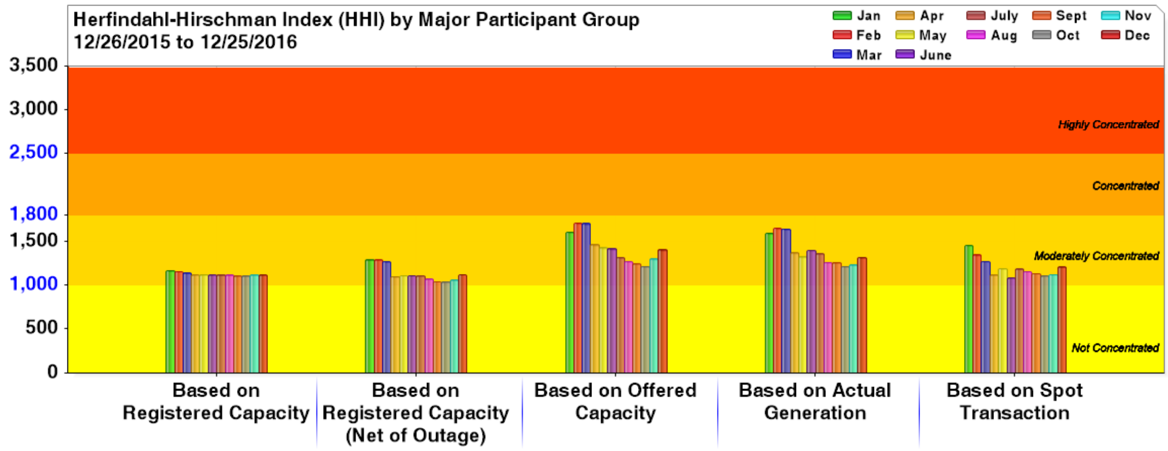


Figure 77. HHI by Participant – System

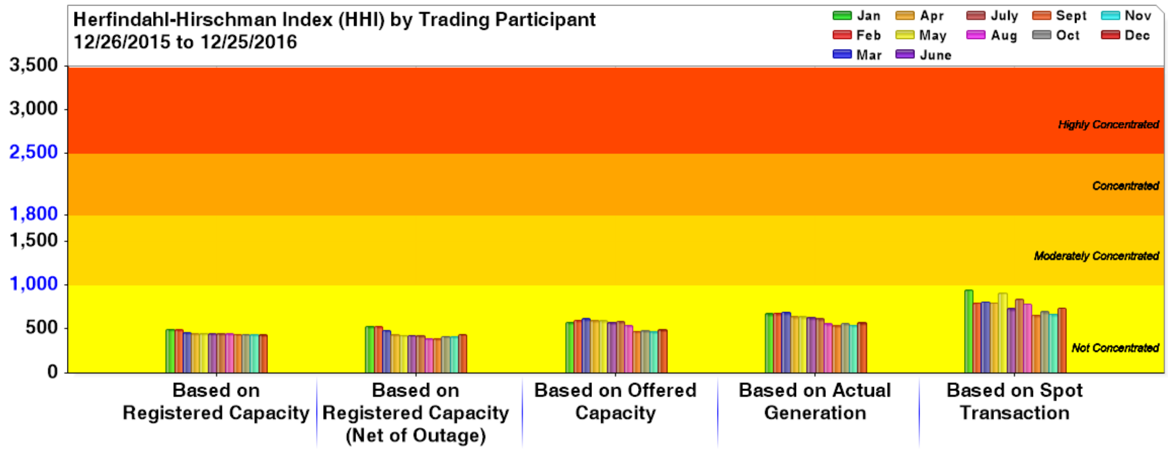
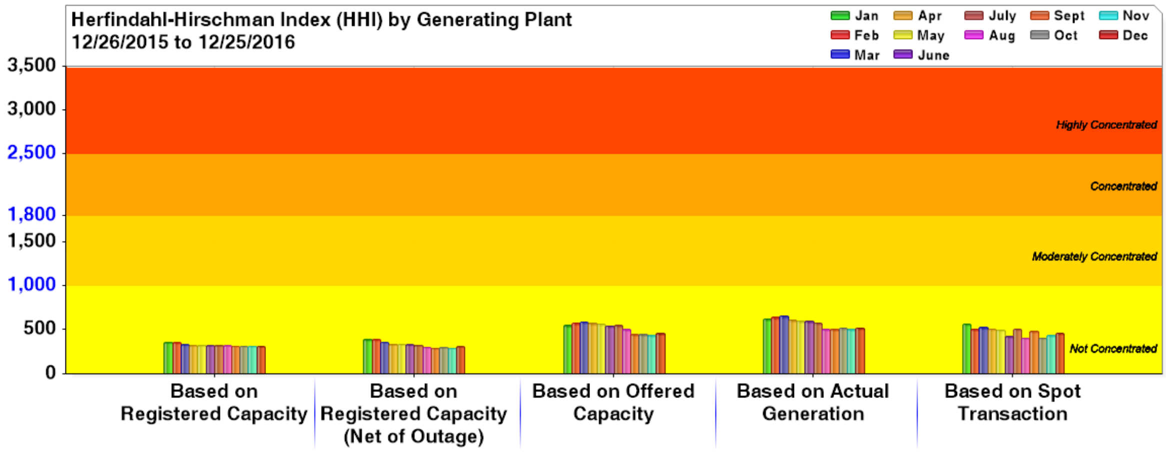


Figure 78. HHI by Plant – System



APPENDIX 'A'

List of WESM Registered Capacities as of 25 December 2016 – Luzon

Market Participant Name	Market Trading Node	Type	Classification	Registered Capacity (Pmax, MW)
1590 Energy Corporation	1BAUANG_G01	Oil-Based	Scheduled	200.0
Absolut Distillers Inc.	3ADISOL_G01	Solar	Must dispatch	1.6
Alternergy Wind One Corporation**	3AWOC_G01	Wind	Must dispatch	54.0
Anda Power Corporation	1ANDA_G01	Coal	Scheduled	82.0
Angat Hydropower Corporation	1ANGAT_A	Hydro	Scheduled	18.0
Angat Hydropower Corporation	1ANGAT_M	Hydro	Scheduled	200.0
AP Renewables Inc.	3MKBN_A	Geothermal	Scheduled	126.0
AP Renewables Inc.	3MKBN_B	Geothermal	Scheduled	126.0
AP Renewables Inc.	3MKBN_C	Geothermal	Scheduled	110.0
AP Renewables Inc.	3MKBN_D	Geothermal	Scheduled	40.0
AP Renewables Inc.	3MKBN_E	Geothermal	Scheduled	40.0
AP Renewables Inc.	3ORMAT_G01	Geothermal	Scheduled	12.0
AP Renewables Inc.	3TIWI_A	Geothermal	Scheduled	118.0
AP Renewables Inc.	3TIWI_B	Geothermal	Scheduled	43.7
AP Renewables Inc.	3TIWI_C	Geothermal	Scheduled	114.0
Aseagas Corporation	3LIAN_G01	Biomass	Non-scheduled NRE	7.3
Asia Pacific Energy Corporation	1APEC_G01	Coal	Scheduled	52.0
Bac-Man Geothermal Inc.	3BACMAN_G01	Geothermal	Scheduled	120.0
Bac-Man Geothermal Inc.	3BACMAN_G02	Geothermal	Scheduled	20.0
Bataan 2020, Inc.	1BT2020_G01	Biomass	Priority Dispatch	13.0
Bicol Biomass Energy Corporation	3BBEC_G01	Biomass	Non-scheduled NRE	5.0
Bosung Solartec, Inc.	1BOSUNG_G01	Solar	Must dispatch	1.0
Bulacan Solar Energy Corp.	1BULSOL_G01	Solar	Must dispatch	15.0
CIP II Power Corporation	1CIP2_G01	Oil-Based	Scheduled	21.3
CW Marketing and Development Corporation	3HDEPOT_G01	Solar	Must dispatch	1.5
Energy Development Corporation(additional facility)	1BURGOS_G02	Solar	Must dispatch	3.7
Energy Development Corporation (additional facility)	1BURGOS_G03	Solar	Must dispatch	2.7
EDC Burgos Wind Power Corporation	1BURGOS_G01	Wind	Must dispatch	150.0
Enfinity Philippines Renewable Resources Inc.	1CLASOL_G01	Solar	Must dispatch	18.0
First Gen Hydro Power Corporation	1MASIWA_G01	Hydro	Scheduled	12.0
First Gen Hydro Power Corporation	1PNTBNG_U01	Hydro	Scheduled	60.0
First Gen Hydro Power Corporation	1PNTBNG_U02	Hydro	Scheduled	60.0
First Natgas Power Corporation	3SNGAB_G01	Natural Gas	Scheduled	420.0
FGP Corporation (San Lorenzo)	3STA-RI_G05	Natural Gas	Scheduled	264.8
FGP Corporation (San Lorenzo)	3STA-RI_G06	Natural Gas	Scheduled	261.8
First Cabanatuan Renewable Ventures Inc.	1CABSOL_G01	Solar	Must dispatch	9.1
First Gas Power Corporation (Sta Rita)	3STA-RI_G01	Natural Gas	Scheduled	257.3
First Gas Power Corporation (Sta Rita)	3STA-RI_G02	Natural Gas	Scheduled	255.7
First Gas Power Corporation (Sta Rita)	3STA-RI_G03	Natural Gas	Scheduled	265.5
First Gas Power Corporation (Sta Rita)	3STA-RI_G04	Natural Gas	Scheduled	264.0
GNPower Mariveles Coal Plant Ltd. Co.	1MARVEL_G01	Coal	Scheduled	302.0
GNPower Mariveles Coal Plant Ltd. Co.	1MARVEL_G02	Coal	Scheduled	302.0
Green Future Innovations, Inc.	1GFII_G01	Biomass	Priority Dispatch	19.8
Green Innovations for Tomorrow Corporation	1GIFT_G01	Biomass	Non-scheduled NRE	12.0
HEDCOR, Inc.	1SLANGN_G01	Hydro	Must dispatch	2.4
HEDCOR, Inc.	1NMHC_G03	Hydro	Must dispatch	1.2
HEDCOR, Inc.	1NMHC_G01	Hydro	Must dispatch	3.8
Hedcor Sabangan, Inc.**	1SABANG_G01	Hydro	Must dispatch	14.3
Isabela Biomass Energy Corporation**	1IBEC_G01	Biomass	Priority Dispatch	18.3
Jobin-SQM Inc.	1SUBSOL_G01	Solar	Must dispatch	7.1
Maibarara Geothermal, Inc.	3MGPP_G01	Geothermal	Scheduled	20.0
Majestics Energy Corporation**	3MEC_G01	Solar	Must dispatch	32.9
Masinloc Power Partners Co. Ltd.	1MSINLO_G01	Coal	Scheduled	315.0
Masinloc Power Partners Co. Ltd.	1MSINLO_G02	Coal	Scheduled	315.0
Masinloc Power Partners Co. Ltd.	1MSNLO_BATG	Battery	Scheduled	10.0
Mirae Asia Energy Corporation	1MAEC_G01	Solar	Must dispatch	16.3
Montalban Methane Power Corp.	2MMPP_G01	Biomass	Priority Dispatch	5.1
nv vogt Philippines Solar Energy Three, Inc.	1ARMSOL_G01	Solar	Must dispatch	7.1
nv vogt Philippines Solar Energy Four, Inc.	1DALSOL_G01	Solar	Must dispatch	5.9
National Irrigation Administration	1NIABAL_G01	Hydro	Non-scheduled	6.0
Next Generation Power Technology Corp.	1MARSOL_G01	Solar	Must dispatch	16.0
North Luzon Renewable Energy Corporation**	1CAPRIS_G01	Wind	Must dispatch	81.0
North Wind Power Development Corporation**	1NWIND_G01	Wind	Must dispatch	33.0
North Wind Power Development Corporation**	1NWIND_G02	Wind	Must dispatch	18.9
One Subic Power Generation Corporation	1S_ENRO_G01	Oil-Based	Scheduled	110.0

List of WESM Registered Capacities as of 25 December 2016 – Luzon (cont'd)

Market Participant Name	Market Trading Node	Type	Classification	Registered Capacity (Pmax, MW)
Panasia Energy, Inc.	1LIMAY_A	Oil-Based	Scheduled	270.0
Panasia Energy, Inc.	1LIMAY_B	Oil-Based	Scheduled	270.0
Pangea Green Energy Philippines, Inc.	2PNGEA_G01	Biomass	Priority Dispatch	1.3
People's Energy Services Inc.	3BART_G01	Hydro	Non-scheduled NRE	1.8
Petron Corporation	1PETRON_G01	Coal	Scheduled	70.0
PetroSolar Corporation	1PETSOL_G01	Solar	Must dispatch	45.5
Prime Meridian PowerGen Corporation	3AVION_U01	Natural Gas	Scheduled	50.3
Prime Meridian PowerGen Corporation	3AVION_U02	Natural Gas	Scheduled	50.3
PSALM Corporation	1CASECN_G01	Hydro	Scheduled	165.0
PSALM Corporation	1HEDCOR_G01	Hydro	Scheduled	30.0
PSALM Corporation	3BOTOCA_G01	Hydro	Scheduled	20.8
PSALM Corporation	3CALIRY_G01	Hydro	Scheduled	28.0
PSALM Corporation	3KAL_G01	Hydro	Scheduled	180.0
PSALM Corporation	3KAL_G02	Hydro	Scheduled	180.0
PSALM Corporation	3KAL_G03	Hydro	Scheduled	180.0
PSALM Corporation	3KAL_G04	Hydro	Scheduled	180.0
PSALM Corporation	3MALAYA_G01	Oil-Based	Scheduled	300.0
PSALM Corporation	3MALAYA_G02	Oil-Based	Scheduled	350.0
Quezon Power (Philippines) Ltd. Co.	3QPPL_G01	Coal	Scheduled	459.0
RASLAG Corp.	1RASLAG_G01	Solar	Must dispatch	9.0
RASLAG Corp.	1RASLAG_G02	Solar	Must dispatch	13.1
Republic Cement & Building Materials, Inc.	3RCBMI_G01	Oil-Based	Scheduled	6.4
Republic Cement & Building Materials, Inc.	3RCBMI_G02	Oil-Based	Scheduled	6.4
San Jose City I Power Corporation	1IPOWER_G01	Biomass	Priority Dispatch	10.8
San Miguel Energy Corporation	1SUAL_G01	Coal	Scheduled	647.0
San Miguel Energy Corporation	1SUAL_G02	Coal	Scheduled	647.0
SEM-Calaca Power Corporation	3CALACA_G01	Coal	Scheduled	300.0
SEM-Calaca Power Corporation	3CALACA_G02	Coal	Scheduled	300.0
SMC Consolidated Power Corporation	1SMC_G01	Coal	Scheduled	150.0
Smith Bell Mini-Hydro Corporation	1SMBELL_G01	Hydro	Must dispatch	1.8
SN Aboitiz Power - Benguet, Inc.	1BINGA_U01	Hydro	Scheduled	35.0
SN Aboitiz Power - Benguet, Inc.	1BINGA_U02	Hydro	Scheduled	35.0
SN Aboitiz Power - Benguet, Inc.	1BINGA_U03	Hydro	Scheduled	35.0
SN Aboitiz Power - Benguet, Inc.	1BINGA_U04	Hydro	Scheduled	35.0
SN Aboitiz Power - Benguet, Inc.	1AMBUK_U01	Hydro	Scheduled	35.0
SN Aboitiz Power - Benguet, Inc.	1AMBUK_U02	Hydro	Scheduled	35.0
SN Aboitiz Power - Benguet, Inc.	1AMBUK_U03	Hydro	Scheduled	35.0
SN Aboitiz Power - Magat, Inc.	1MAGAT_U01	Hydro	Scheduled	95.0
SN Aboitiz Power - Magat, Inc.	1MAGAT_U02	Hydro	Scheduled	95.0
SN Aboitiz Power - Magat, Inc.	1MAGAT_U03	Hydro	Scheduled	95.0
SN Aboitiz Power - Magat, Inc.	1MAGAT_U04	Hydro	Scheduled	95.0
Solar Philippines Calatagan Corporation	3CALSOL_G01	Solar	Must dispatch	49.7
Solar Philippines Commercial Rooftop Projects, Inc.**	2SMNRTH_G01	Solar	Must dispatch	1.2
South Luzon Thermal Energy Corporation	3SLTEC_G01	Coal	Scheduled	121.0
South Luzon Thermal Energy Corporation**	3SLTEC_G02	Coal	Scheduled	122.9
South Premiere Power Corporation	3ILIJAN_G01	Natural Gas	Scheduled	600.0
South Premiere Power Corporation	3ILIJAN_G02	Natural Gas	Scheduled	600.0
Southwest Luzon Power Generation Corporation**	3SLPGC_G01	Coal	Scheduled	140.0
Southwest Luzon Power Generation Corporation**	3SLPGC_G02	Coal	Scheduled	140.0
SPARC-Solar Powered Agri-Rural Communities Corporation	1ZAMSOL_G01	Solar	Must dispatch	5.0
SPARC-Solar Powered Agri-Rural Communities Corporation	1BTNSOL_G01	Solar	Must dispatch	5.0
SPARC-Solar Powered Agri-Rural Communities Corporation	1SPABUL_G01	Solar	Must dispatch	1.2
Strategic Power Development Corporation	1SROQUE_U01	Hydro	Scheduled	145.0
Strategic Power Development Corporation	1SROQUE_U02	Hydro	Scheduled	145.0
Strategic Power Development Corporation	1SROQUE_U03	Hydro	Scheduled	145.0
Therma Luzon, Inc.	3PAGBIL_G01	Coal	Scheduled	382.0
Therma Luzon, Inc.	3PAGBIL_G02	Coal	Scheduled	382.0
Therma Mobile, Inc.	2TMO_G01	Oil-Based	Scheduled	66.0
Therma Mobile, Inc.	2TMO_G02	Oil-Based	Scheduled	67.2
Therma Mobile, Inc.	2TMO_G03	Oil-Based	Scheduled	57.0
Therma Mobile, Inc.	2TMO_G04	Oil-Based	Scheduled	52.0
Trans-Asia Power Generation Corporation	1T_ASIA_G01	Oil-Based	Scheduled	50.0
United Pulp and Paper Company, Inc.	1UPPC_G01	Coal	Scheduled	26.0
Valenzuela Solar Energy, Inc.	2VALSOL_G01	Solar	Must dispatch	8.5
Vivant Sta. Clara Northern Renewables Generation Corporation	1BAKUN_G01	Hydro	Scheduled	76.0
YH Green Energy, Incorporated	1YHGRN_G01	Solar	Must dispatch	12.6
Total Registered Capacity (Pmax) - Luzon				**14,469.8**

**Capacities are used for modelling purposes only. These are subject to change upon submission of the ERC Certification of plant specifications based on ERC's ocular technical inspection.

APPENDIX 'B'

List of WESM Registered Capacities as of 25 December 2016 – Visayas

Market Participant Name	Region	Market Trading Node	Type	Classification	Registered Capacity (Pmax, MW)
Bohol I Electric Cooperative, Inc.	Visayas	7JANOPO_G01	Hydro	Non-scheduled NRE	5.0
Cebu Energy Development Corporation	Visayas	5CEDC_G01	Coal	Scheduled	246.0
Cebu Private Power Corporation	Visayas	5CPPC_G01	Oil-Based	Scheduled	70.0
Central Azucarera de San Antonio	Visayas	8CASA_G01	Biomass	Non-scheduled	4.0
Central Negros Power Reliability, Inc.	Visayas	6CENPRI_U02	Oil-Based	Scheduled	4.2
Central Negros Power Reliability, Inc.	Visayas	6CENPRI_U01	Oil-Based	Scheduled	4.2
Central Negros Power Reliability, Inc.	Visayas	6CENPRI_U03	Oil-Based	Scheduled	4.2
Cosmo Solar Energy, Inc.	Visayas	8COSMO_G01	Solar	Must dispatch	5.7
East Asia Utilities Corporation	Visayas	5EAUC_G01	Oil-Based	Scheduled	49.6
Energy Development Corporation	Visayas	6NASULO_G01	Geothermal	Scheduled	48.3
First Farmers Holdings Corporation	Visayas	6FFHC_G01	Biomass	Priority Dispatch	13.0
First Toledo Solar Energy Corporation	Visayas	5TOLSOL_G01	Solar	Must dispatch	49.0
Green Core Geothermal Inc.	Visayas	6PAL1A_G01	Geothermal	Scheduled	112.5
Green Core Geothermal Inc.	Visayas	6PAL2A_G01	Geothermal	Scheduled	79.2
Green Core Geothermal Inc.	Visayas	4LGPP_G01	Geothermal	Scheduled	107.0
Hawaiian-Philippine Company**	Visayas	6HPCO_G01	Biomass	Non-scheduled NRE	3.0
Helios Solar Energy Corporation	Visayas	6HELIOS_G01	Solar	Must dispatch	108.1
ICS Renewables	Visayas	6AMLA_G01	Hydro	Non-scheduled NRE	0.9
KEPCO Salcon Power Corporation	Visayas	5KSPC_G01	Coal	Scheduled	103.0
KEPCO Salcon Power Corporation	Visayas	5KSPC_G02	Coal	Scheduled	103.0
Monte Solar Energy Inc.	Visayas	6MNTSOL_G01	Solar	Must dispatch	14.4
Negros Island Solar Power Inc.	Visayas	6CARSOL_G01	Solar	Must dispatch	27.2
Negros Island Solar Power Inc.	Visayas	6MANSOL_G01	Solar	Must dispatch	40.5
Palm Concepcion Power Corporation	Visayas	8PALM_G01	Coal	Scheduled	135.0
Panay Energy Development Corporation	Visayas	8PEDC_U01	Coal	Scheduled	83.7
Panay Energy Development Corporation	Visayas	8PEDC_U02	Coal	Scheduled	83.7
Panay Energy Development Corporation	Visayas	8PEDC_U03	Coal	Scheduled	150.0
Panay Power Corporation	Visayas	8GLOBAL_G01	Oil-Based	Scheduled	10.0
Panay Power Corporation**	Visayas	8PPC_G01	Oil-Based	Scheduled	72.0
Panay Power Corporation**	Visayas	8AVON_G01	Oil-Based	Scheduled	20.0
PetroWind Energy Inc.**	Visayas	8PWIND_G01	Wind	Must dispatch	36.0
First Soleq Energy Corp.	Visayas	4PHSOL_G01	Solar	Must dispatch	24.5
PSALM Corporation	Visayas	4LEYTE_A	Geothermal	Scheduled	538.0
San Carlos Bioenergy, Inc.	Visayas	6SCBE_G01	Biomass	Non-scheduled	8.3
San Carlos Solar Energy, Inc.	Visayas	6SACASL_G01	Solar	Must dispatch	19.8
San Carlos Solar Energy, Inc.	Visayas	6SACASL_G02	Solar	Must dispatch	19.8
San Carlos Sun Power, Inc.	Visayas	6SACSUN_G01	Solar	Must dispatch	46.8
Silay Solar Power, Inc.	Visayas	6SLYSOL_G01	Solar	Must dispatch	20.0
SPC Island Power Corporation	Visayas	7BDPP_G01	Oil-Based	Scheduled	16.2
SPC Island Power Corporation	Visayas	8PDPP_G01	Oil-Based	Scheduled	15.0
SPC Island Power Corporation	Visayas	8PDPP3_G01	Oil-Based	Scheduled	62.0
SPC Power Corporation	Visayas	5CDPPI_G01	Oil-Based	Scheduled	18.0
SPC Power Corporation	Visayas	5CDPPI_G02	Oil-Based	Scheduled	18.0
Sta Clara Power Corporation	Visayas	7LOBOC_G01	Hydro	Non-scheduled NRE	1.2
Sulu Electric Power and Light (Phils.), Inc.	Visayas	4SEPSOL_G01	Solar	Must dispatch	45.0
Sunwest Water and Electric Company 2, Inc.	Visayas	8SUWECO_G01	Hydro	Non-scheduled	8.0
Toledo Power Company	Visayas	5TPC_G01	Oil-Based	Scheduled	40.0
Toledo Power Company	Visayas	5TPC_G02	Coal	Scheduled	145.0
PHINMA Energy Corporation	Visayas	8GUIM_G01	Oil-Based	Non-scheduled	3.0
PHINMA Energy Corporation	Visayas	8STBAR_PB	Oil-Based	Scheduled	20.0
PHINMA Energy Corporation	Visayas	8STBAR_PB2	Oil-Based	Scheduled	20.0
Trans-Asia Renewable Energy Corporation**	Visayas	8SLWIND_G01	Wind	Must dispatch	54.0
Universal Robina Corporation**	Visayas	6URC_G01	Biomass	Priority Dispatch	40.0
Victorias Milling Company,Inc.	Visayas	6VMC_G01	Biomass	Non-scheduled NRE	34.0
Total Registered Capacity (Pmax) - Visayas					**3,008.9**

**Capacities are used for modelling purposes only. These are subject to change upon submission of the ERC Certification of plant specifications based on ERC's ocular technical inspection.