GE
Energy Consulting

PJM Renewable Integration Study

Task 3A Part D

Production Cost Analysis

Prepared for: PJM Interconnection, LLC.

Prepared by: General Electric International, Inc.

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imagination at work

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Acronyms and Nomenclatures

2% BAU	2% Renewable Penetration – Business-As-Usual Scenario
14% RPS	14% Renewable Penetration – RPS Scenario
20% LOBO	20% Renewable Penetration – Low Offshore Best Onshore Scenario
20% LODO	20% Renewable Penetration – Low Offshore Dispersed Onshore Scenario
20% HOBO	20% Renewable Penetration – High Offshore Best Onshore Scenario
20% HSBO	20% Renewable Penetration – High Solar Best Onshore Scenario
30% LOBO	30% Renewable Penetration – Low Offshore Best Onshore Scenario
30% LODO	30% Renewable Penetration – Low Offshore Dispersed Onshore Scenario
30% HOBO	30% Renewable Penetration – High Offshore Best Onshore Scenario
30% HSBO	30% Renewable Penetration – High Solar Best Onshore Scenario
AEPS	Alternative Energy Portfolio Standard
AGC	Automatic Generation Control
AWS/AWST	AWS Truepower
Bbl.	Barrel
BAA	Balancing Area Authority
BAU	Business as Usual
BTU	British Thermal Unit
CA	Intertek AIM's Cycling⬍Advisor ™ tool
CAISO	California Independent System Operator
CC/CCGT	Combined Cycle Gas Turbine
CEMS	Continuous Emissions Monitoring Systems
CF	Capacity Factor
CO2	Carbon Dioxide
CV	Capacity Value
DA	Day-Ahead
DR	Demand Response
DSM	Demand Side Management
EI	Eastern Interconnection

EIPC	Eastern Interconnection Planning Collaborative
ELCC	Effective Load Carrying Capability
ERCOT	Electricity Reliability Council of Texas
EST	Eastern Standard Time
EUE	Expected Un-served Energy
EWITS	Eastern Wind Integration and Transmission Study
FERC	Federal Energy Regulatory Commission
FLHR	Full Load Heat Rate
FSA	PJM Facilities Study Agreement
GE	General Electric International, Inc. / GE Energy Consulting
GE MAPS	GE's "Multi Area Production Simulation" model
GE MARS	GE's "Multi Area Reliability Simulation" model
GT	Gas Turbine
GW	Gigawatt
GWh	Gigawatt Hour
HA	Hour Ahead
HSBO	High Solar Best Onshore Scenarios
HOBO	High Offshore Best Onshore Scenarios
HR	Heat Rate
HVAC	Heating, Ventilation, and Air Conditioning
IPP	Independent Power Producers
IRP	Integrated Resource Planning
ISA	PJM Interconnection Service Agreement
ISO-NE	Independent System Operator of New England
kV	kilovolt
kW	kilowatt
kWh	kilowatt-hour
lbs	Pounds (British Imperial Mass Unit)
LDC	Load Duration Curve

LM	Intertek AIM's Loads Model ™ tool
LMP	Locational Marginal Prices
LNR	Load Net of Renewable Energy
LOBO	Low Offshore Best Onshore Scenarios
LODO	Low Offshore Dispersed Onshore Scenarios
LOLE	Loss of Load Expectation
MAE	Mean-Absolute Error
MAPP	Mid-Atlantic Power Pathway
MMBtu	Millions of BTU
MVA	Megavolt Ampere
MW	Megawatts
MWh	Megawatt Hour
NERC	North American Electric Reliability Corporation
NOx	Nitrogen Oxides
NREL	National Renewable Energy Laboratory
NWP	"Numerical Weather Prediction" model
O&M	Operational & Maintenance
PATH	Potomac Appalachian Transmission Highline
PJM	PJM Interconnection, LLC.
PPA	Power Purchase Agreement
PRIS	PJM Renewable Integration Study
PRISM	Probabilistic Reliability Index Study Model
PROBE	"Portfolio Ownership & Bid Evaluation Model" of PowerGEM
PSH	Pumped Storage Hydro
PV	Photovoltaic
REC	Renewable Energy Credit
Rest of EI	Rest of Eastern Interconnection
RPS	Renewable Portfolio Standard
RT	Real Time

RTEP	Regional Transmission Expansion Plan
SC/SCGT	Simple Cycle Gas Turbine
SCUC/EC	Security Constrained Unit Commitment / Economic Dispatch
SOx	Sulfur Oxides
ST	Steam Turbine
TARA	“Transmission Adequacy and Reliability Assessment” software of PowerGEM
UCT	Coordinated Universal Time
VOC	Variable Operating Cost
WI	Western Interconnection

1 Hourly Production Simulation

1.1 Analysis of Base Scenarios

GE MAPS hourly security constrained production costing simulation was performed for all the 11 base scenarios listed in Table 1-1. This section presents the results of the hourly simulation, with focus in a number of themes that are most relevant to the system response to volatility and intermittency of renewable energy with implications for the type of mitigating measures potentially available to PJM.

This study did not evaluate potential impacts on PJM Capacity Market results due to reduced generator revenues from the wholesale energy market, nor did it evaluate the impact of renewables to rate payers. It is conceivable that lower energy prices would be at least partially offset by higher capacity prices.

Table 1-1: Summary of the Study Scenarios

Scenario	Renewable Penetration	Scenario Names	Wind + Solar Siting
1	2%	2% BAU	Existing Plants (Business as Usual- Reference)
2	14%	14% RPS	PJM Queue & Mandates (RPS Compliance – Base Case)
3	20%	20% HOBO	High Offshore, Best Onshore
4	20%	20% LOBO	Low Offshore, Best Onshore
5	20%	20% LODO	Low Offshore, Dispersed Onshore
6	20%	20% HSBO	High Solar, Best Onshore
7	30%	30% HOBO	High Offshore, Best Onshore
8	30%	30% LOBO	Low Offshore, Best Onshore
9	30%	30% LODO	Low Offshore, Dispersed Onshore
10	30%	30% HSBO	High Solar, Best Onshore

Throughout this section, to evaluate the impact of higher penetration of renewable resources, most of the results are shown in comparison with the 2% BAU and 14% RPS scenarios.

The scenarios considered are characterized primarily by the overall level of the solar and wind energy penetration relative to the total generation in PJM, and moreover by the relative mix of the different wind (onshore and offshore) and solar (central and distributed) in the system.

Following sections present results of the hourly security constrained production cost simulations. In order to present the data in a readable format, separate charts are provided for 20% and 30% scenario results; however, for comparison, most of the charts also include results for the 2% and 14% scenarios.

1.2 Operational Performance of Renewable Resources

Energy Generation

Figure 1-1 and Figure 1-2 show the size of delivered annual renewable energy as percent of PJM load. The total delivered energy does not exactly match the percentage penetration assigned to each scenario. This is mainly due to about 1.5% of PJM energy being served by non-wind/non-solar renewable sources, but also due to variation in wind and solar generation profiles and the curtailment.

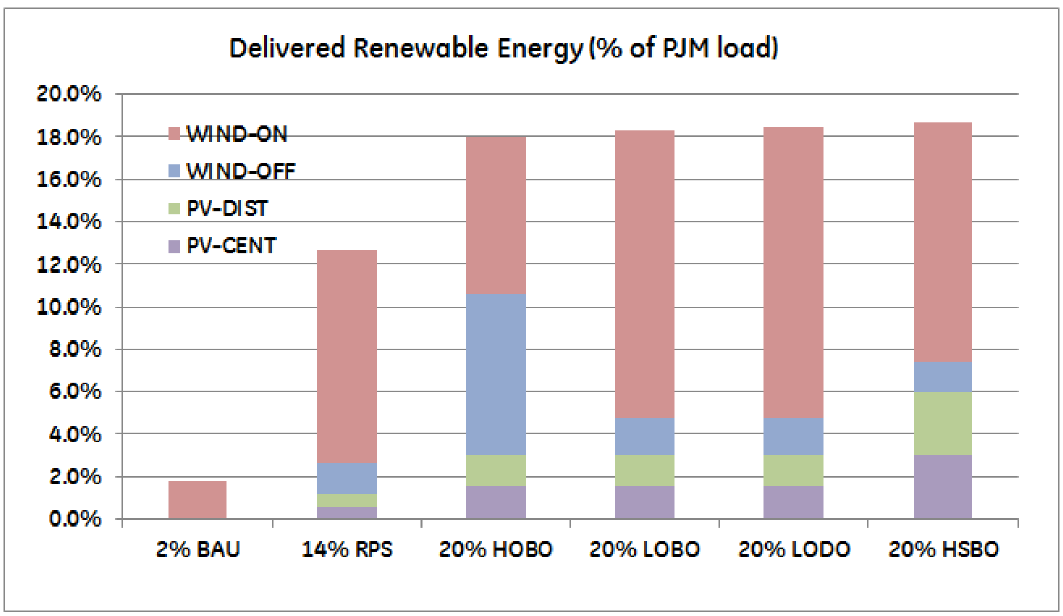

Figure 1-1: Delivered Renewable Energy as % of PJM Load (20% Scenarios)

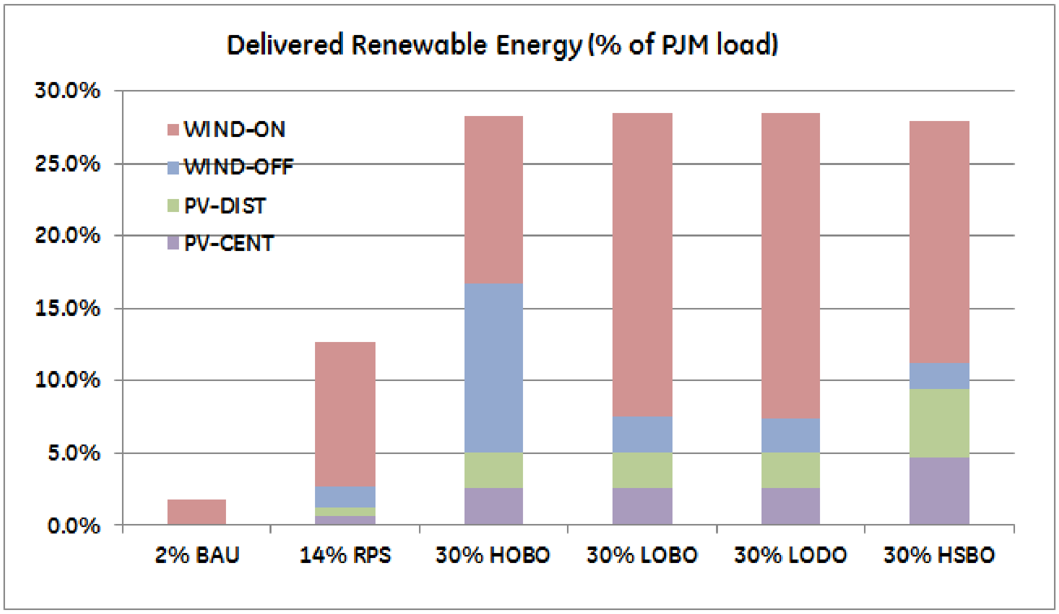

Figure 1-2: Delivered Renewable Energy as % of PJM Load (30% Scenarios)

Figure 1-3 and Figure 1-4 show the generation by type as percent of the total PJM load for each of the scenarios. Coal generation is relatively high in HSBO scenarios, most likely due to need for more baseload unit commitment for off-peak coverage relative to other scenarios (with HSBO having more renewable generation during on-peak and less during off-peak compared to the other scenarios). CCGT generation is lowest in the HOBO scenarios. Coal generation, on the other hand, is higher in the HOBO scenario. These results are most likely due to the higher concentration of wind generation in the eastern PJM, and higher concentration of coal generation in the western PJM.

Additional information provided by these figures concern the net imports and net exports in each scenario. The 2% and 14% scenarios show significant net imports from PJM neighbors.

There is also some net import observed in 30% LOBO scenario. Other 30% scenarios - and also to a lesser extent the 20% HSBO scenario - result in net exports. Further investigation indicates that the net import in the 30% LOBO scenario is the result of the transmission overlay process used to upgrade the transmission in each scenario. The transmission overlay process results in different final transmission configurations in different scenarios. In the 30% LOBO case, the transmission overlay process resulted in relatively higher relief of congestion in the western region of PJM. As a result, there is less curtailment of wind energy in the 30% LOBO scenario, and less congestion allows more import of cheaper energy from the west into PJM.

The net imports are shown by the blue areas on the top of the generation stack. The net exports are shown by the blue areas below the X-axis.

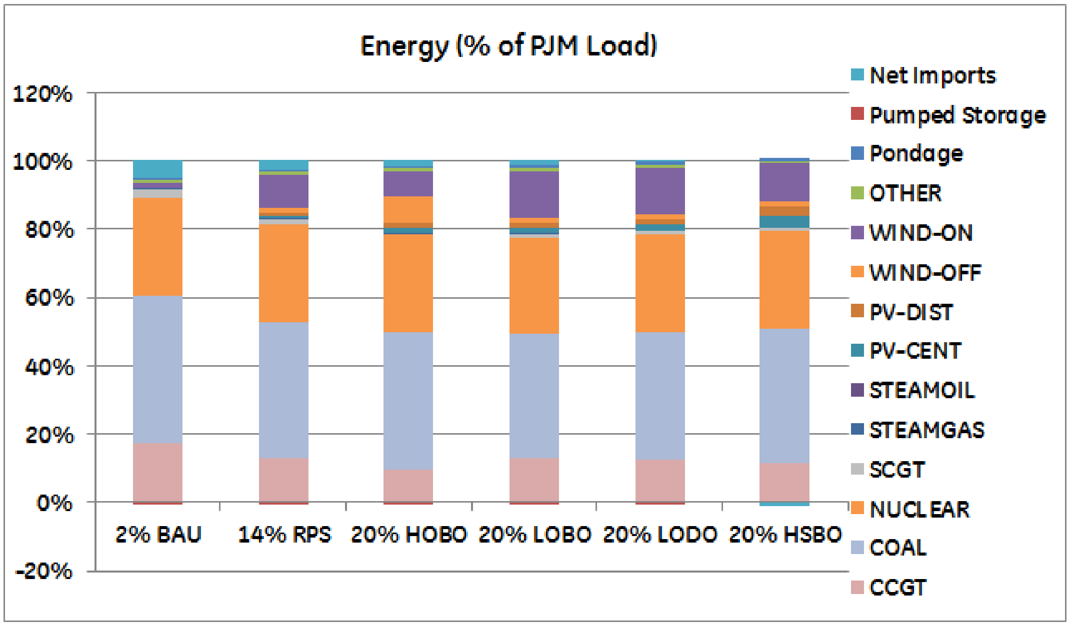

Figure 1-3: Annual Generation of Unit Types as % of PJM Load (20% Scenarios)

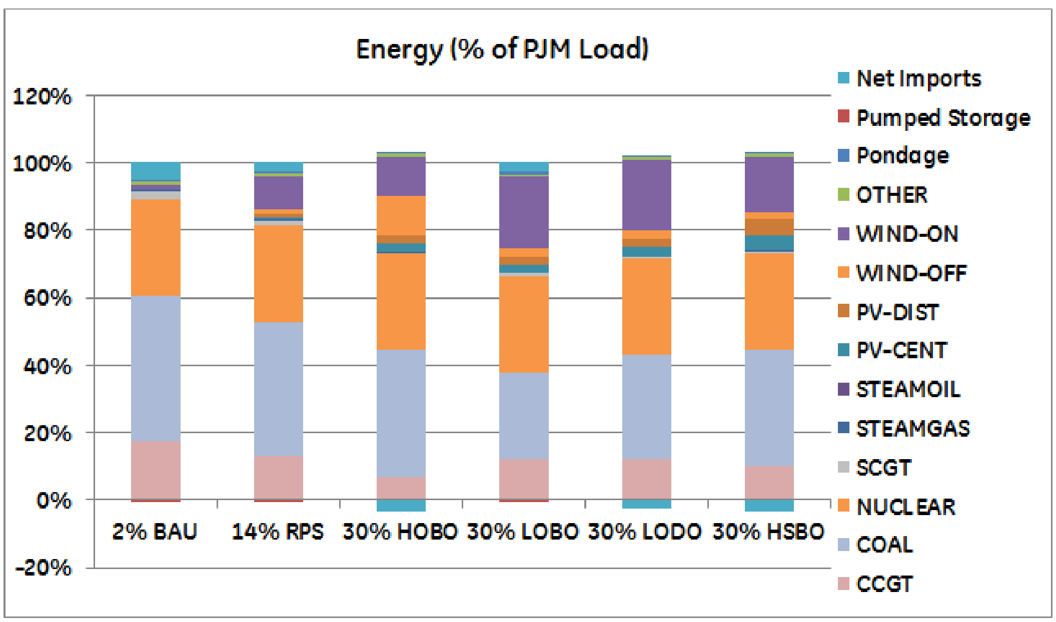

Figure 1-4: Annual Generation of Unit Types as % of PJM Load (30% Scenarios)

Renewable Energy Curtailment

Higher deployment of renewable resources in PJM is expected to increase the likelihood of having surplus energy during low demand periods when curtailment (i.e., spillage) of renewable energy may occur. At such times, in order to ensure instantaneous equilibrium of electricity supply and demand, the thermal plants, which are more expensive to operate compared to renewable resources, are the first in line to be curbed. However, there is limit to how much thermal generation can be curtailed. The limit is met when:

i. Thermal plant generations are reduced to their minimum load points (a committed plant will not be shut off unless absolutely necessary), or

ii. If some above-minimum-load thermal generation is needed to supply operating reserves in order to meet the system operation reserve requirements (this is not being modeled in GE MAPS), or

iii. If some thermal units are designated “must-run” units, which have to be kept operating in order to maintain system reliability.

When all non-renewable options other than nuclear have been exhausted, then additional curtailment would have to come from the renewable resources.

GE MAPS uses a pre-defined priority list of plants to schedule the orderly curtailment of the renewable resources. It is assumed that the curtailment cannot be enforced on distributed generation, beyond the reach of the system operators or their dispatch orders, and therefore distributed generation such as distributed solar are not subject to curtailment.

The transmission system was expanded in each scenario to avoid significantly binding constraints, as explained in section on Hourly Production Costing. Variations in the siting of the renewable generation and the locations of new transmission lines likely account for the relatively minor variations in curtailments in the scenarios.

Figure 1-5 depicts the size of available and curtailed renewable energy under different scenarios. Figure 1-6 takes a closer look for further clarity of the size of the curtailed renewable energy.

Both HOBO and LODO scenarios result in higher curtailment going from 20% to 30% penetration. Both of the HOBO and LODO scenarios show higher net exports under the 30% scenarios, which indicated that some of the potentially curtailed energy was used for experts.

However, the LOBO scenario exhibits higher curtailment in the 20% scenario compared to the 30% scenario, although in absolute terms, difference are small and could be due to variety of reasons, such as local congestion or make up of available flexible thermal generation. As pointed out earlier, the transmission overly process results in relatively lighter congestion in the western PJM in the 30% LOBO scenario, resulting both in lower curtailment and more imports into PJM.

The case of HSBO scenario is perhaps easier to interpret. The HSBO generation coincides with high on-peak periods in PJM. Hence, at a lower 20% penetration level, solar energy appears to help meet the PJM peak demand. As previous figures (and results described later) indicate, higher solar generation squeezes out the CCGT and SCGT generation more that the coal fired generation. However, in the 30% HSBO scenario, some local transmission congestion in an area with high concentration of solar power resulted in significant localized curtailment of renewable energy. The local congestion did not meet the price differential threshold warranting its removal in the transmission overlay process. The 20% and 30% HSBO scenarios also result in higher net exports to neighboring regions compared to other scenarios, more likely due to the coincidence of high renewable production with on-peak demand periods of other regions.

Figure 1-7 shows the proportional amount of curtailed renewable energy relative to the total available renewable energy in each scenario, which range from 0.5% to near 3% (of the total renewable energy) in 20% scenarios (about 0.10% to 0.60% of total energy), and from somewhat below 1.5% to a somewhat above 3% in the 30% scenarios (about 0.45% to 0.90% of total energy). The 30% scenarios also experience higher exports to outside PJM. In the absence of exports, the level of curtailments in 30% scenarios could be higher.

The amount of curtailed energy can be reduced by improving the renewable energy forecast, introducing more flexibility to thermal plant operations, or by facilitating higher non-firm exports to neighboring regions.

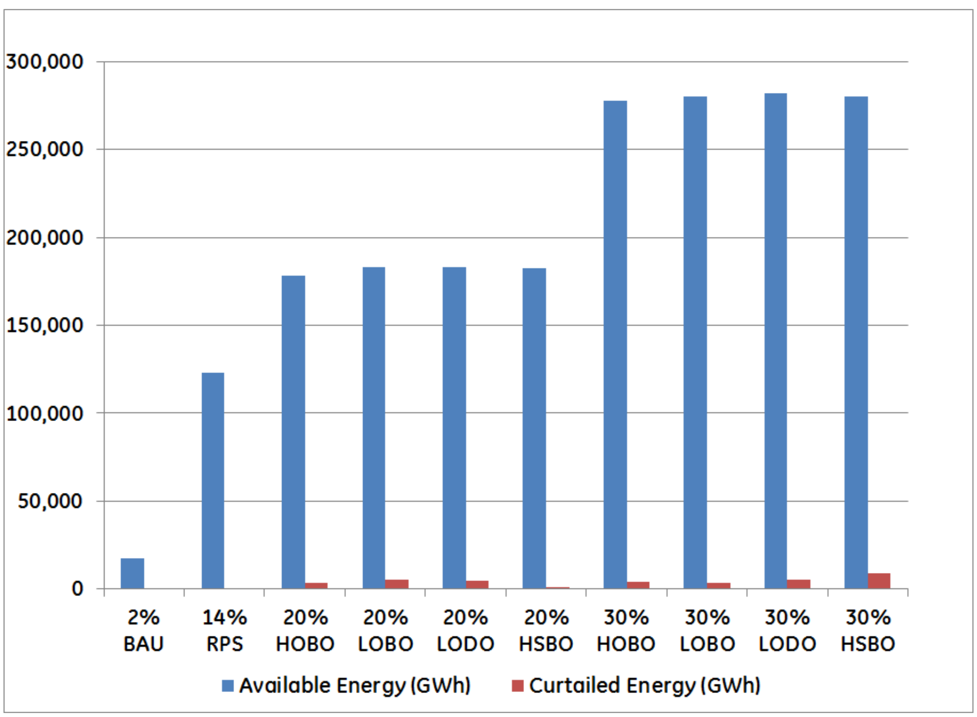

Figure 1-5: Available and Curtailed Renewable Energy

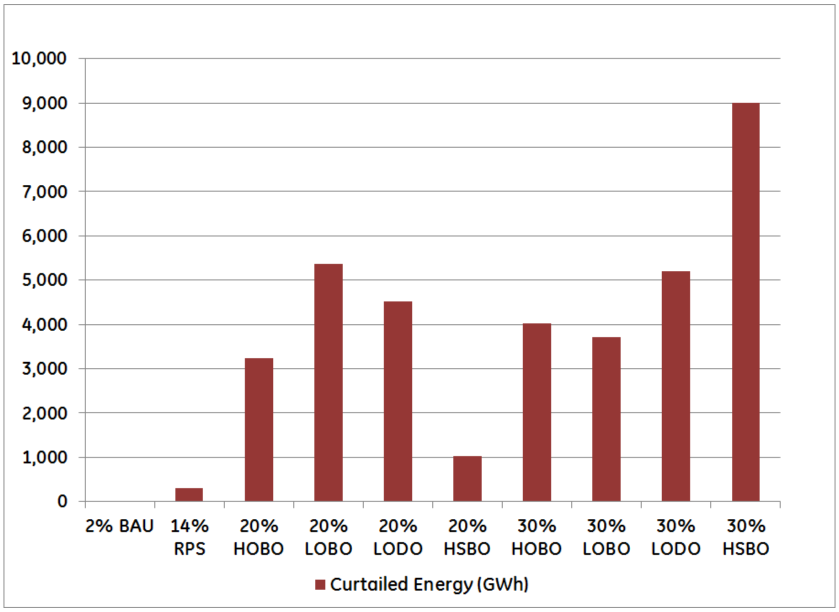

Figure 1-6: Curtailed Renewable Energy

As noted previously, in the 30% HSBO scenario, some local transmission congestion in an area with high concentration of solar power resulted in significant localized curtailment of renewable energy. The local congestion did not meet the price differential threshold warranting its removal in the transmission overlay process.

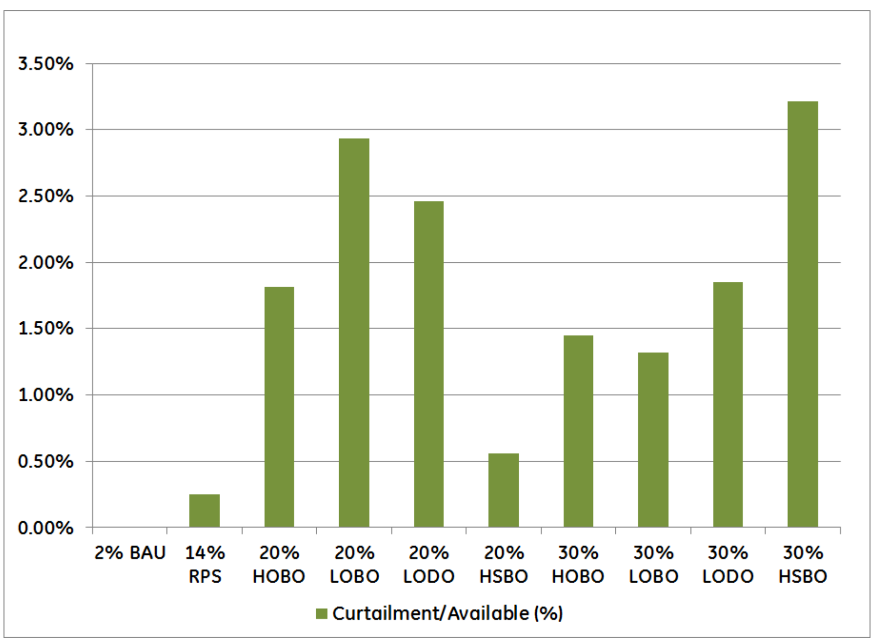

Figure 1-7: Ratio of Curtailed to Available Renewable Energy

1.3 Operational Performance of Thermal Generation

Energy Production

The main impact of changes in penetration levels of renewable resources is change in the total annual energy generation by different plant types, as shown in Figure 1-8 and Figure 1-9, higher penetration of renewable energy in most cases result in lower generation by coal and combined cycle units. Renewable energy, due to its almost zero variable cost is the energy of choice and when available subject to other constraints in the system, it replaces relatively costly fossil-fuel based generation.

The greatest downward impact on the coal generation is in the 20% and 30% LOBO and LODO scenarios. This is caused by higher onshore wind generation in these scenarios, and in some cases due to the proximity of the onshore wind locations to the regions with higher coal generation. Most of the new wind plants are located in the western regions of PJM which also have the greatest share of coal based generation.

Combined cycle generation, on the other hand, are mostly impacted by the 20% and 30% HOBO (high offshore) scenarios, showing the lowest level of generation compared to other 20% and 30% scenarios. The main reason is that there are a greater number of CCGT plants are located in the more densely populated eastern regions of PJM, the regions closes to the offshore wind generation. The offshore wind it is displacing the expensive generation in the east. Also, since the offshore wind is helping to serve load in the east, there is less west to east loading of transmission by the Midwestern wind than in the low offshore scenarios.

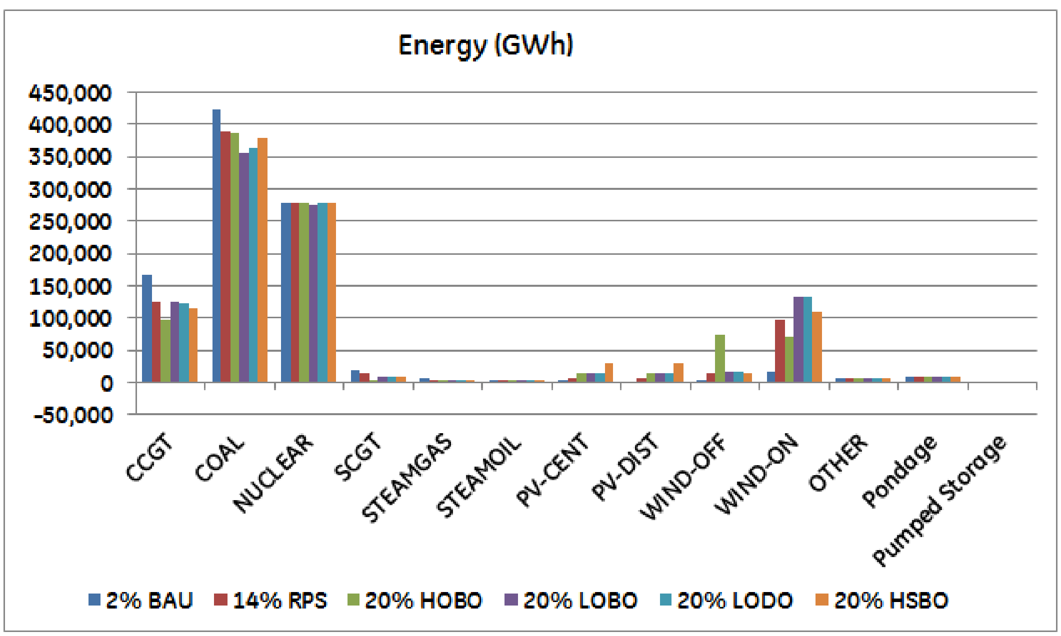

Figure 1-8: Annual Generation by Unit Type (20% Scenarios)

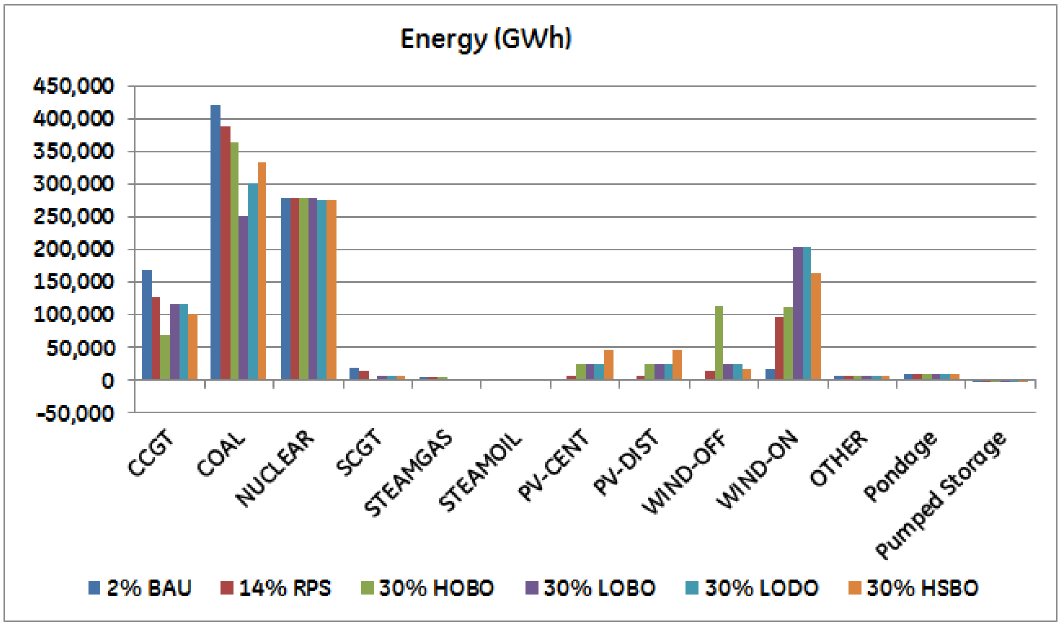

Figure 1-9: Annual Generation by Unit Type (30% Scenarios)

Simple cycle generation is also impacted in most of the scenarios. However, similar to the CCGT plants, the greatest impact on SCGT plants is in the 20% and 30% HOBO scenarios, again mostly due to the proximity of such generation to offshore wind locations.

Figure 1-10 and Figure 1-11 illustrate the impact of higher renewable energy on coal generation, by showing displacement of coal based generation in the each PJM area – and to the extent possible in a one dimensional representation – ordered based on PJM areas from west to east and from north to south. Only areas with coal generation are shown. The regions most impacted appear to be mostly in the western, central, and southern parts of PJM.

The higher 30% penetration of renewable energy results in more drastic reduction in coal based generation. In both 20% and 30% scenarios, the LOBO (low offshore and best onshore) scenarios results in the largest reduction in coal generation the impact is magnified due to proximity of the best site wind generation to high coal generation regions, particularly in the west of PJM and the Appalachian mountain regions.

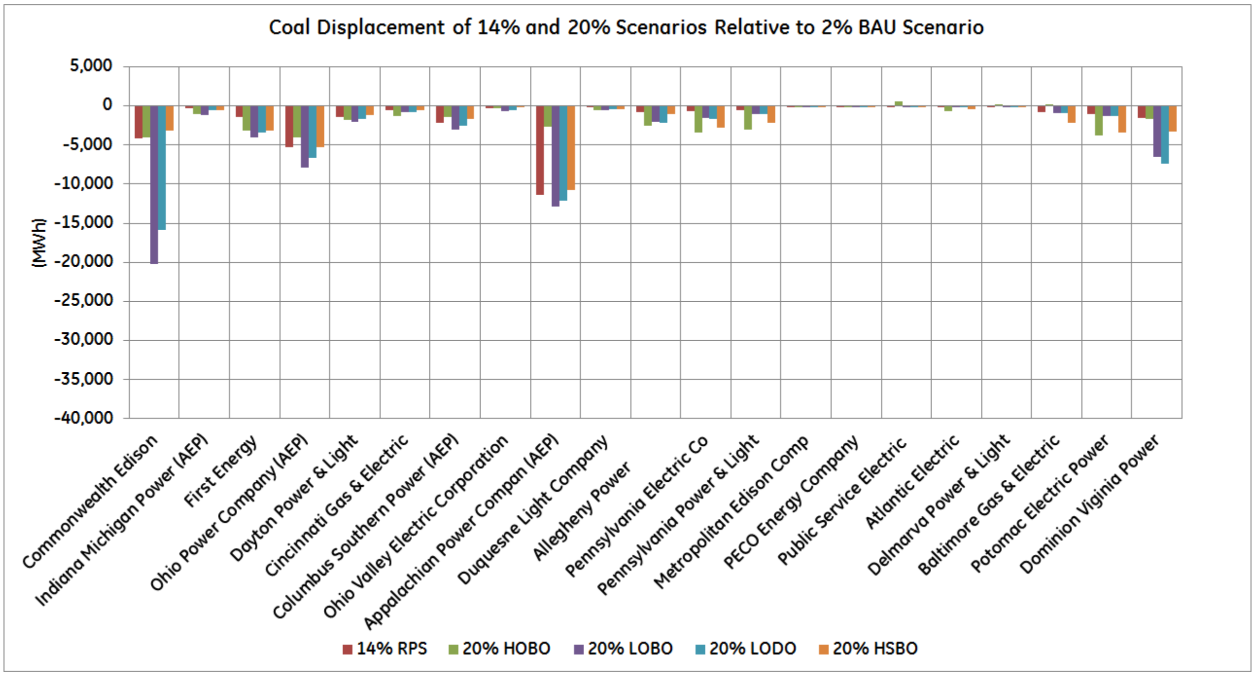

Figure 1-10: Displacement of Coal Units in 14% and 20% Scenarios Relative to the 2% BAU Scenario

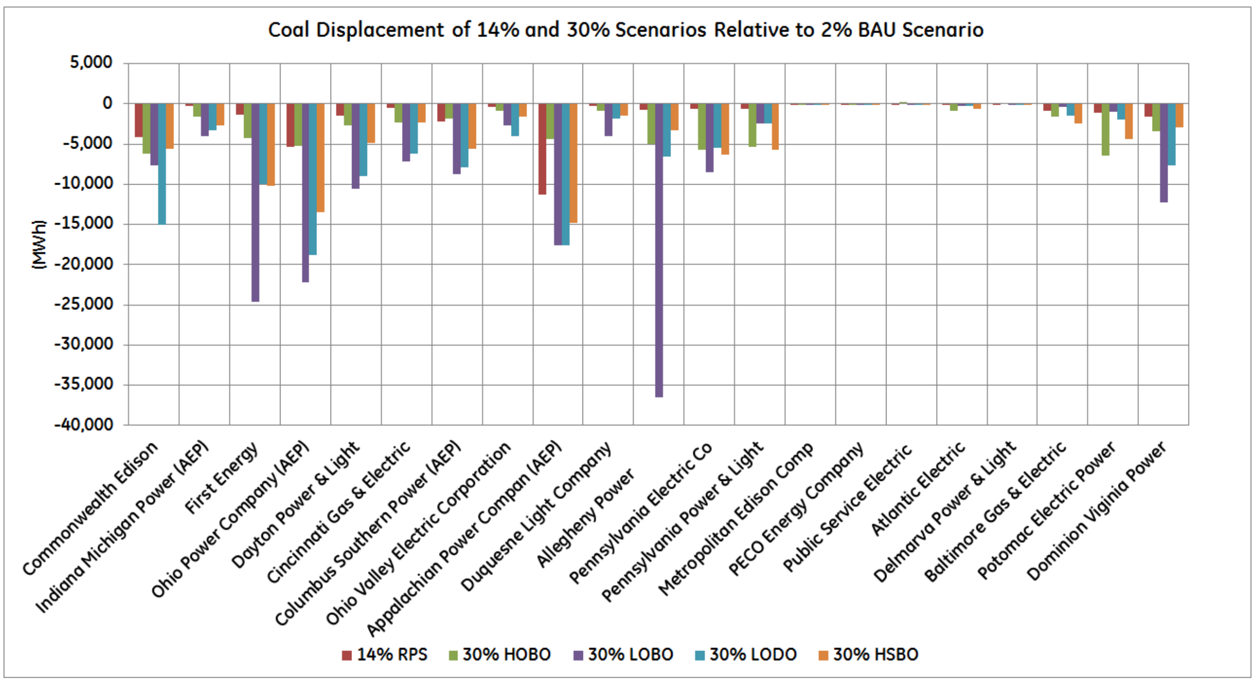

Figure 1-11: Displacement of Coal Units in 14% and 30% Scenarios Relative to the 2% BAU Scenario

Figure 1-12 and Figure 1-13 illustrate the impact of higher renewable energy on combined cycle generation, and showing displacement of CCGT generation in the each PJM area, and also ordered based on PJM areas from west to east and from north to south. Only areas with significant CCGT generation are shown. The regions most impacted appear to be spread across PJM.

The higher 30% penetration of renewable energy results in more drastic reduction in CCGT based generation. In both 20% and 30% scenarios, the HOBO (high offshore and best onshore) scenarios results in the largest reduction in CCGT generation particularly in the eastern regions. The 20% and 30% HSBO scenarios also impact CCGT generation during the on-peak periods.

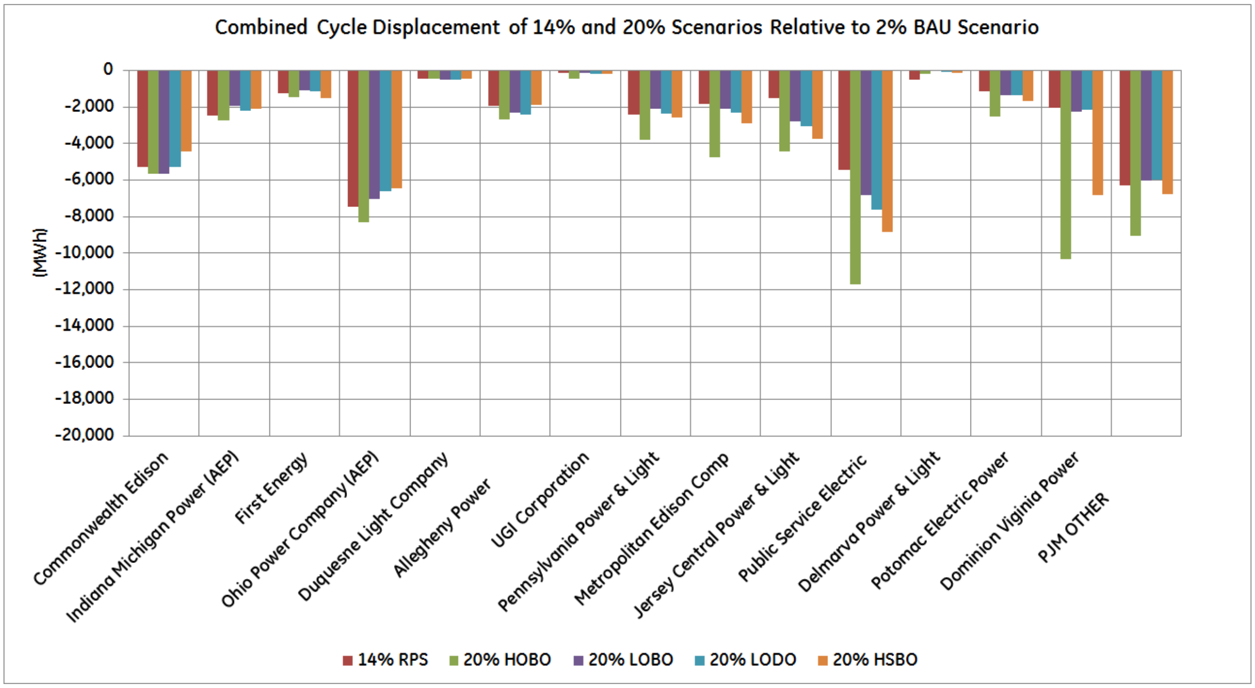

Figure 1-12: Displacement of CCGT Units in 14% and 20% Scenarios Relative to the 2% BAU Scenario

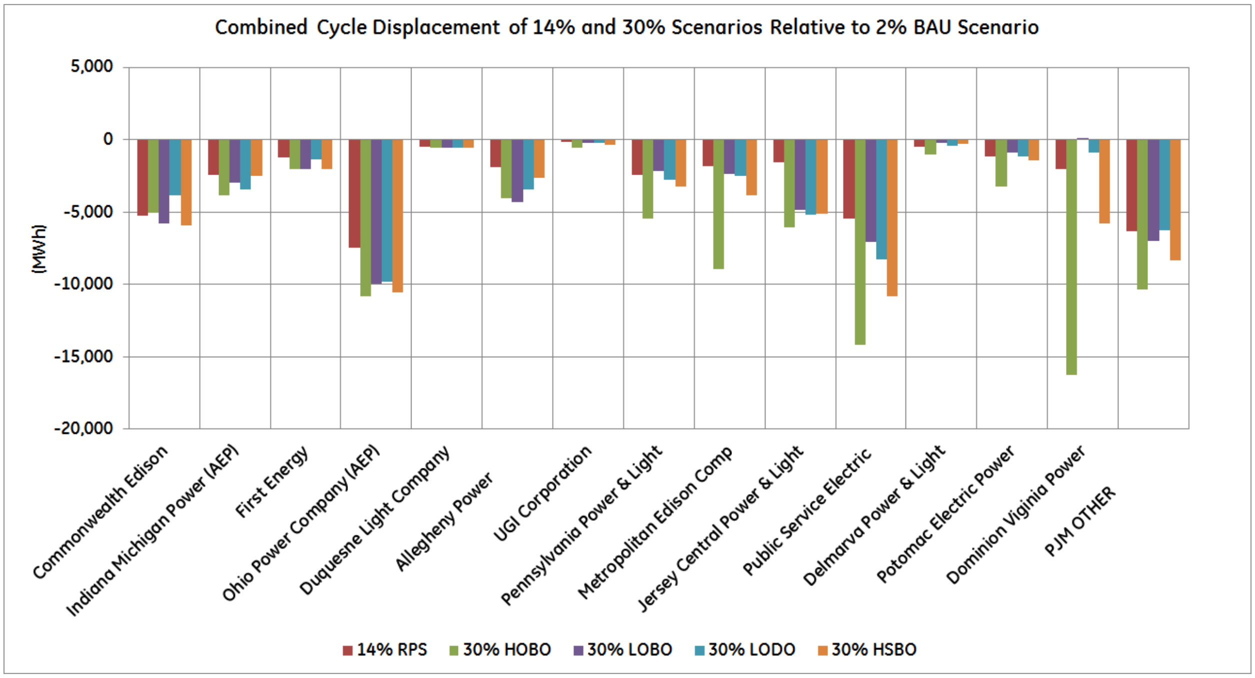

Figure 1-13: Displacement of CCGT Units in 14% and 30% Scenarios Relative to the 2% BAU Scenario

The resulting capacity weighted capacity factors of various thermal generation types are shown in Figure 1-14 and Figure 1-15. Capacity Factor is defined as the ratio of annual generation of a plant divided by the total generation that could have resulted if the plant ran at full load every hour of the year. Results are consistent with the previous observations on the impact of higher renewable generation on the thermal generation types that were described previously.

In the 20% scenarios, CCGT plants run at average capacity factors of about 30% to 40%. The CCGT capacity factors drop to about 20% to 35% in the 30% scenarios. The lower ranges correspond to the HOBO and HSBO scenarios.

The coal plants run at capacity factors of about 60% to 70% in the 20% scenarios. Coal unit capacity factors drop to about 45% to 65% in the 30% scenarios. The largest drops are associated with the LOBO scenarios. In this study, 2026 gas prices are assumed to be about two to three times the price of coal.

The nuclear units appear to maintain a steady capacity factor of about 90% in both 20% and 30% scenarios. It should be noted that these results are based on additional transmission overlays that were added based on iterative running of the GE MAPS model to successively decrease observed congestions down to a threshold minimum level as described elsewhere. Earlier model runs without the transmission overlays showed large congestions impacting operations of some of the nuclear plants.

As expected, SCGT plants have very low capacity factors, with the greatest impact due to the HOBO scenarios, likely due to SCGT plants proximity to the offshore wind resources.

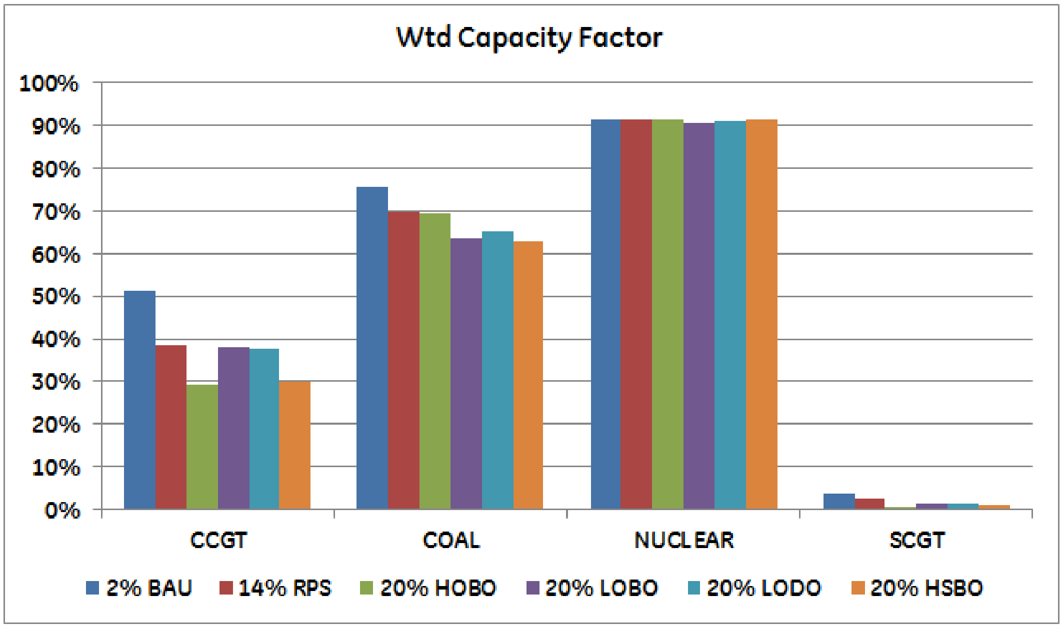

Figure 1-14: Capacity Factor by Unit Type (20% Scenarios)

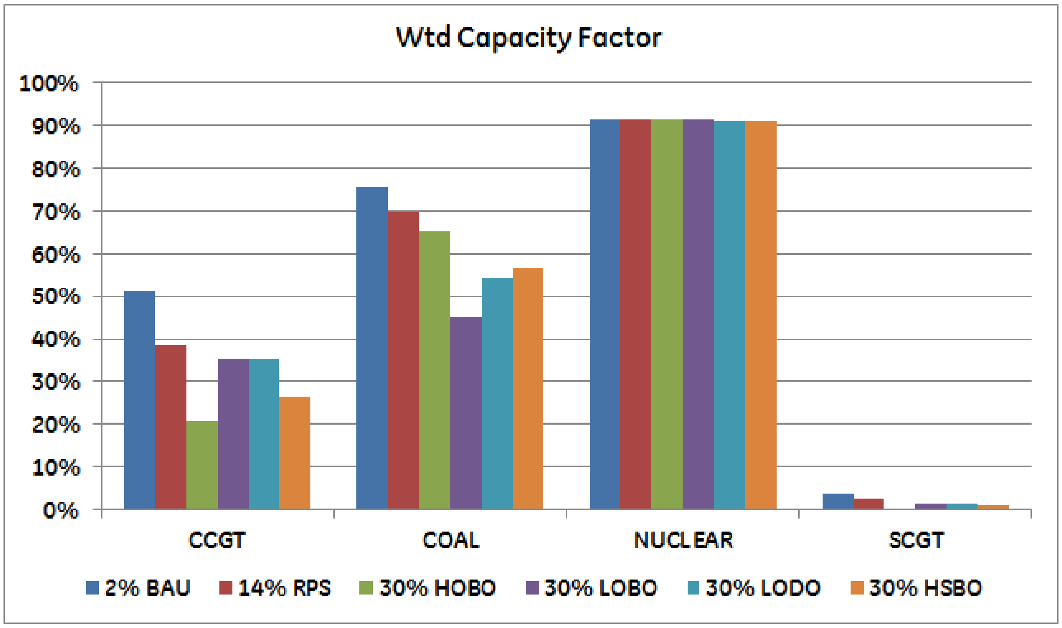

Figure 1-15: Capacity Factor by Unit Type (30% Scenarios)

Unit Performance

Other performance metrics of the thermal plants are shown in the following figures. Figure 1-16 and Figure 1-17 show such metrics for the coal plants. These performance metrics include the following:

- Number of Starts per year (right vertical axis)
- Capacity Factor (right vertical axis)
- Normalized Net Revenue ($/MW-year) (right vertical axis)
- Average Number of Hours Online in the year (left vertical axis)

The most dramatic impact on hours of operations and net revenues of Coal generation is under the HOBO cases. This could be due to different congestion (which is an artifact of how the transmission reinforcements were done) or could be because of the different time-of-day profiles for the off-shore wind. Hours of operations directly impacts the net revenues, but it is only one of the drivers. Another factor is the general level of generator prices. Net revenues drop going from 20% to 30% level of renewable penetration. As noted previously, one likely reason for the particular impact of HOBO scenarios is that the offshore wind is located near the PJM Load Centers in the east. The offshore wind is displacing the expensive generation in the east. Also, since the offshore wind is helping to serve load in the east, less generation from the West is flowing to serve load in the East, and hence, the inexpensive coal serves the load in the West. Also as can be seen in the SCGT charts below, with less SCGT type units running, which are price setting marginal units when running, the overall PJM price levels are expected to be lower under HOBO scenarios, one consequence of which is lowering the net revenues of thermal plants.

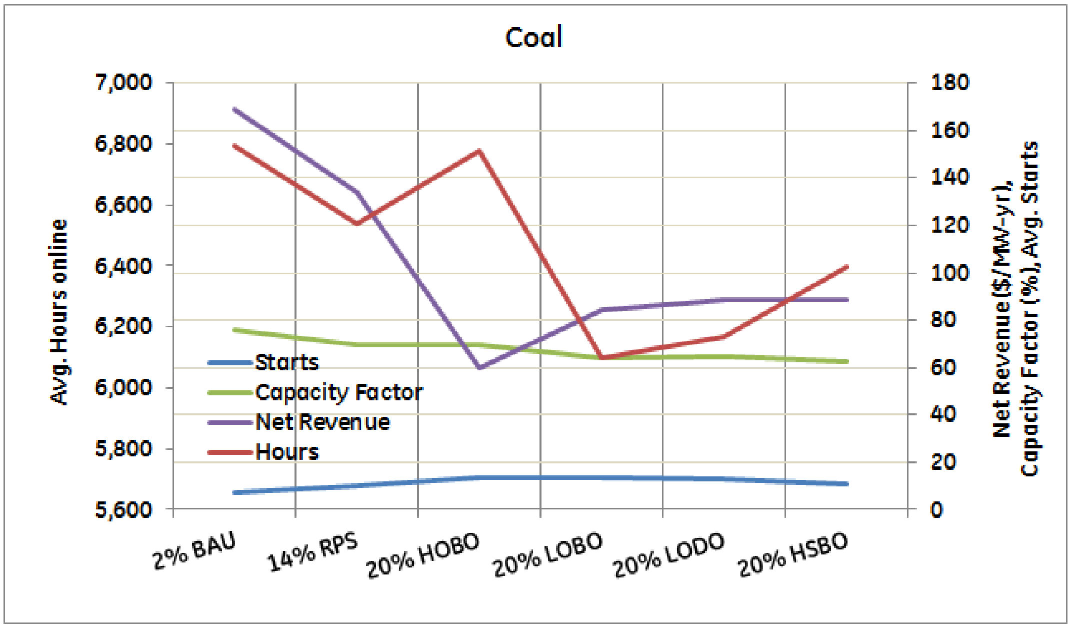

Figure 1-16: Performance of Coal Units (20% Scenarios)

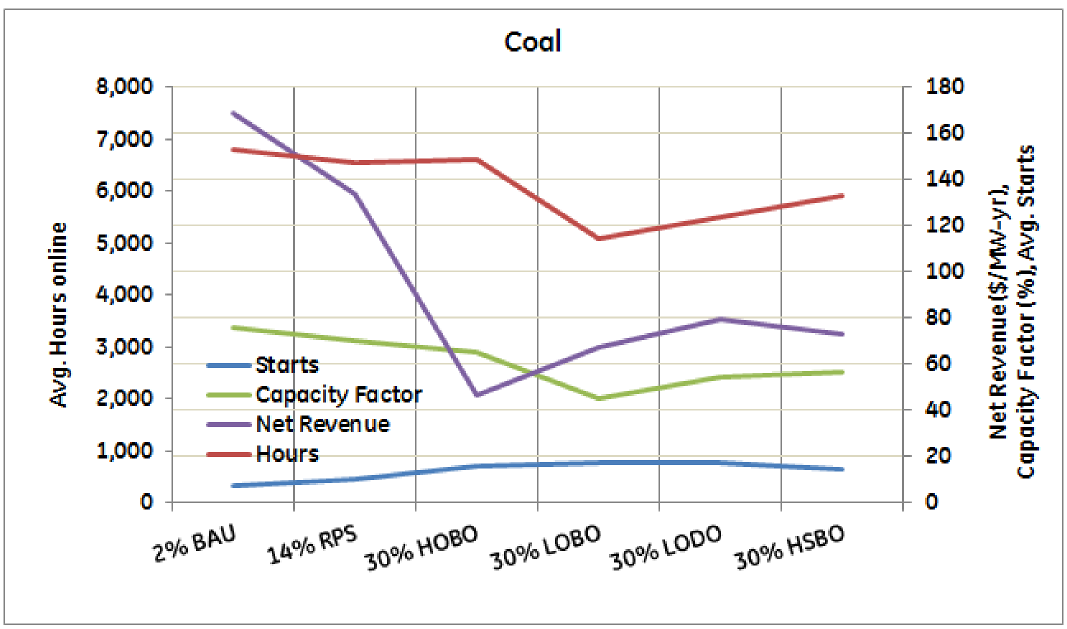

Figure 1-17: Performance of Coal Units (30% Scenarios)

Similar metrics for the CCGT plants are provided in Figure 1-18and Figure 1-19. In addition to impacts on hours of operations and net revenues, it can be seen that the number of starts, and hence cycling, of CCGTs increases significantly in higher renewable penetration scenarios.

The HOBO scenarios appeared to increase the operation hours of Coal based units, but have the opposite impact on the CCGT generation.

The HSBO scenarios increase the number of starts and lower the hours of operation of the CCGT plants – most probably occurring during the on-peak high solar energy periods.

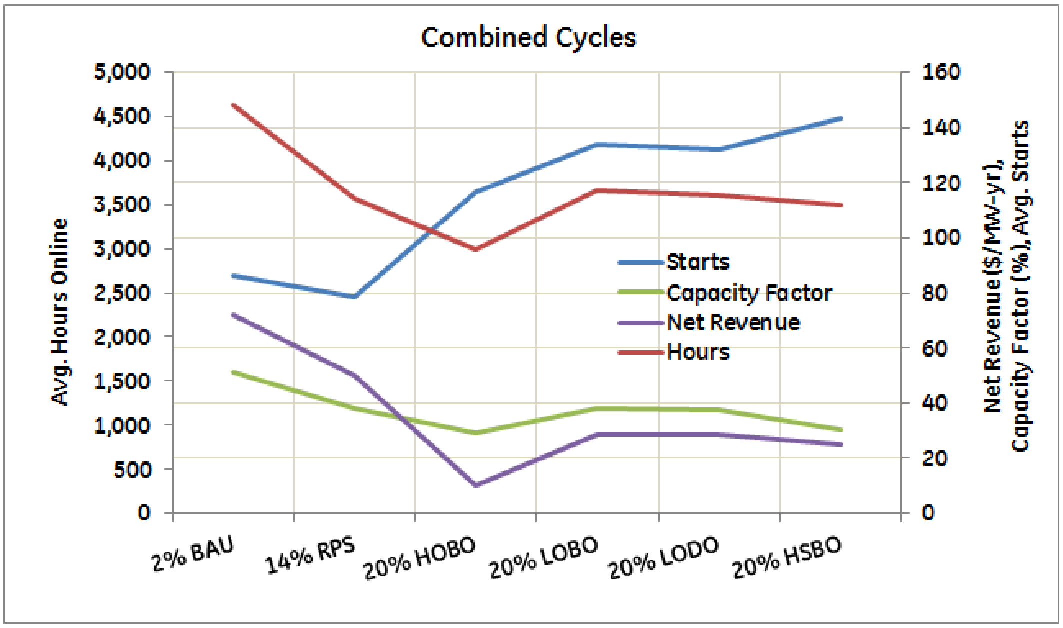

Figure 1-18: Performance of Combined Cycle Units (20% Scenarios)

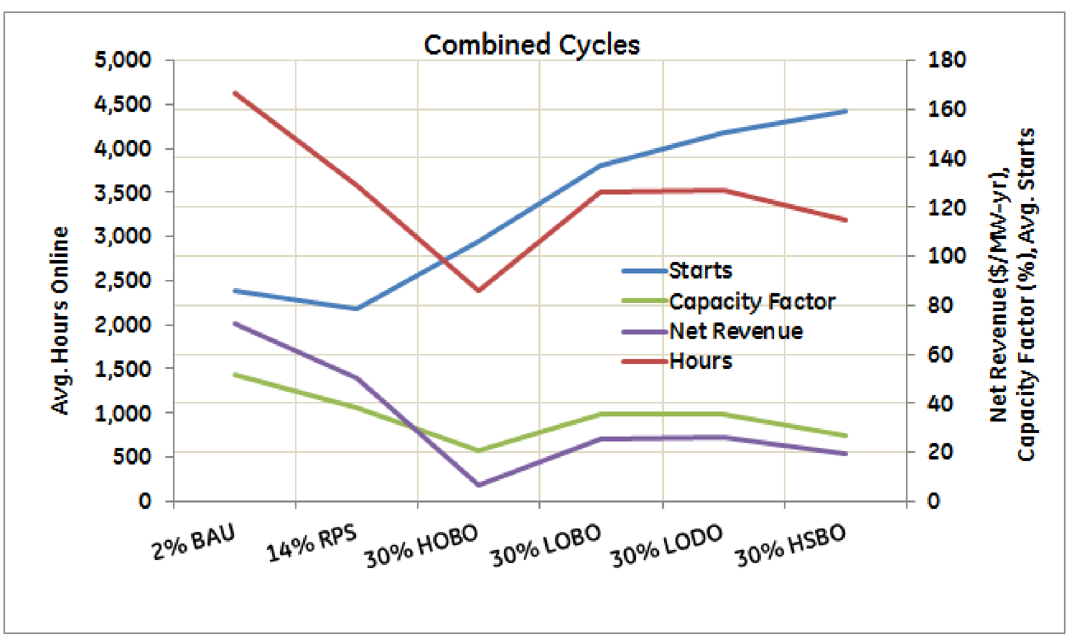

Figure 1-19: Performance of Combined Cycle Units (30% Scenarios)

Figure 1-20 and Figure 1-21 depict the performance of SCGT plants. The HOBO scenarios have impacts on SCGT plants similar to the Coal based and CCGT plants. The HSBO scenarios also lower the hours of operation of SCGT plants – again most likely due to the coincidence of HSBO generation with times of typical high utilization of SCGT plants.

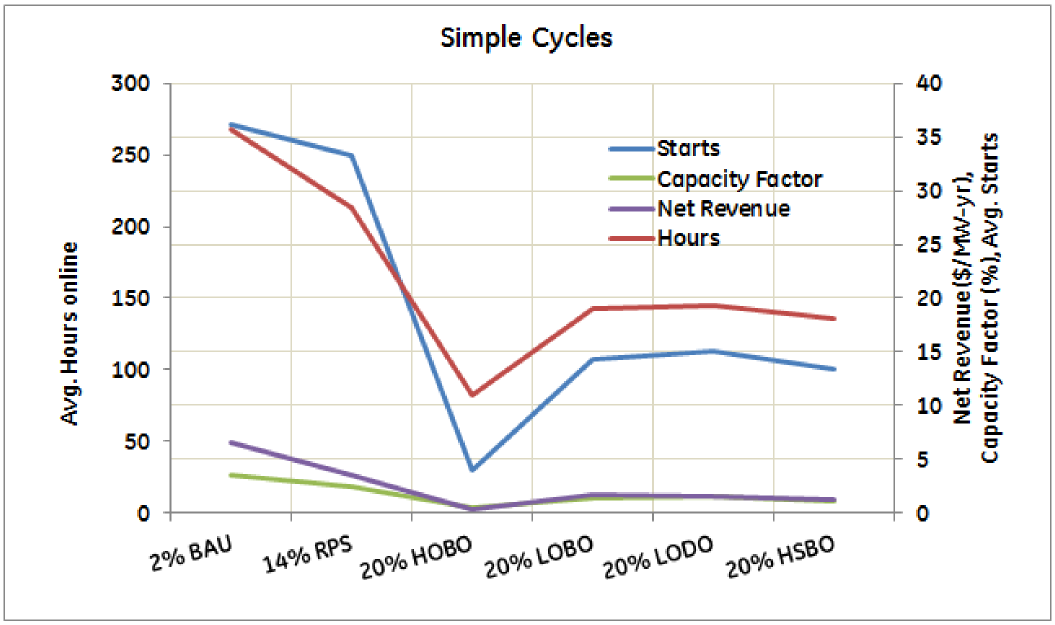

Figure 1-20: Performance of Simple Cycle Units (20% Scenarios)

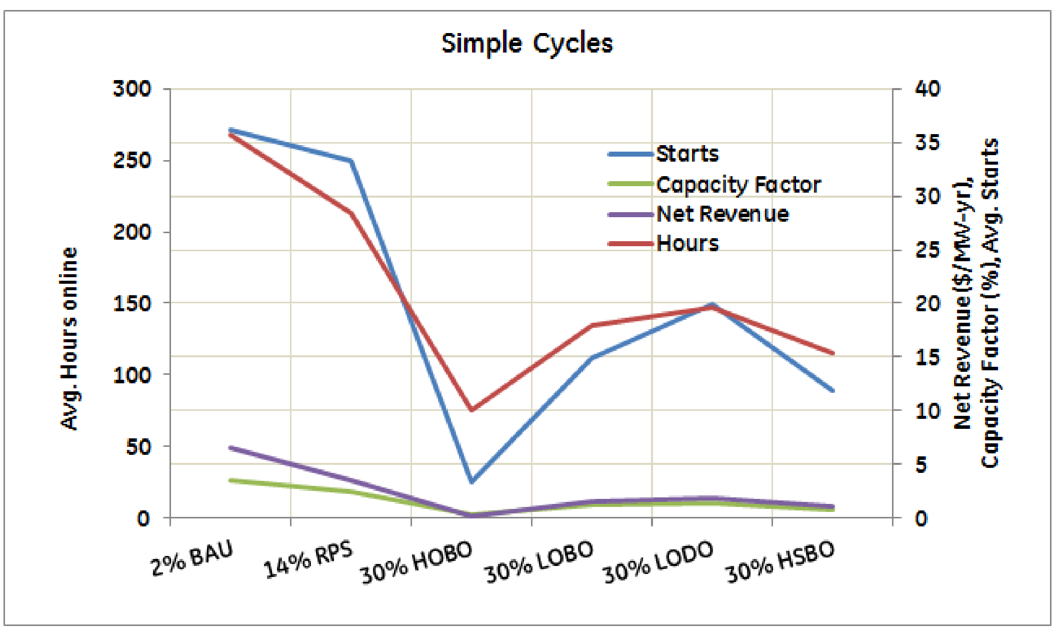

Figure 1-21: Performance of Simple Cycle Units (30% Scenarios)

The 20% and 30% HOBO scenarios impact all thermal units in a similar way in terms of lowering the normalized net revenues of thermal plants, although they impact the hours of operations differently, by increasing them in case of the coal based units.

1.4 Environmental Emissions

As discussed, higher penetration of renewable energy results in lowering the contribution of thermal resources to PJM energy requirements. Less thermal energy also results in less environmental emissions in the 20% and 30% scenarios. Figure 1-22 and Figure 1-23show that criteria pollutants (i.e., NOx and SOx) and greenhouse gasses (i.e., CO2) are reduced in these scenarios. These figures also show that the LOBO scenarios have the greatest impact on lowering of these environmental emissions, in line with the LOBO scenarios having the greatest impact on lowering of coal based generation.

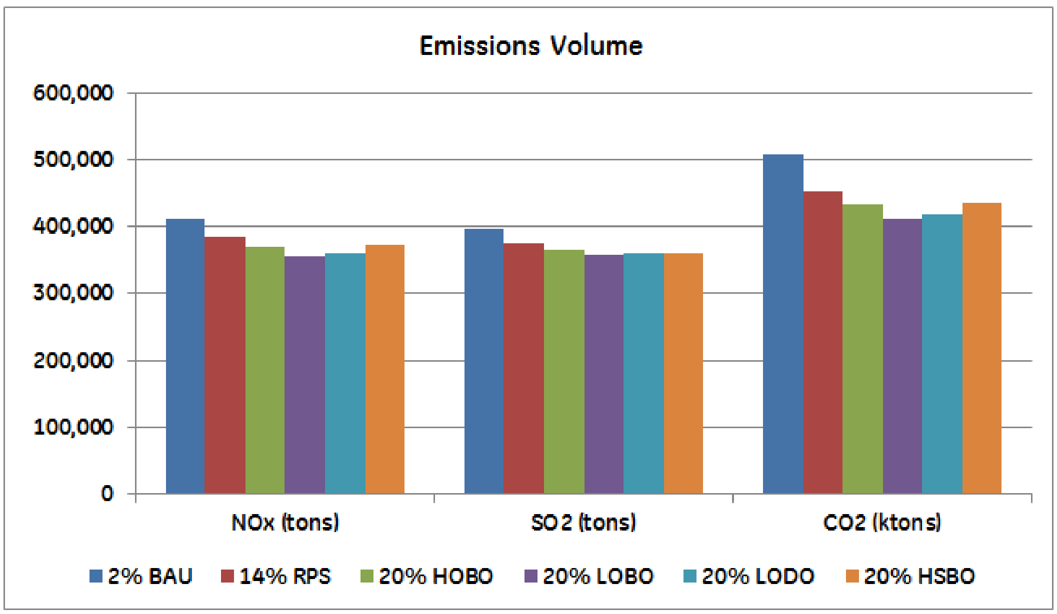

Figure 1-22: Emission Volumes of the 20% Scenarios

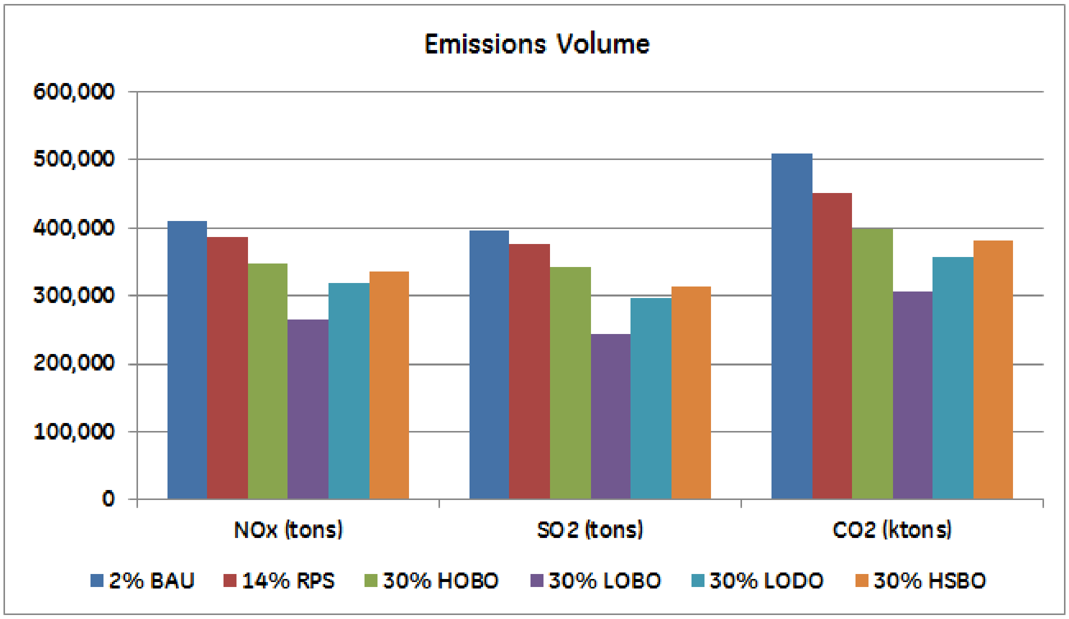

Figure 1-23: Emission Volumes of the 30% Scenarios

1.5 LMP and Zonal Prices

As noted in the previous sections on operational performance of thermal generation, higher renewable energy penetration results in significant reduction of thermal generation. Reduced thermal generation also results in less utilization of more expensive thermal generation whose marginal variable costs tend to set the marginal prices within PJM. Hence, it is expected that deployment of more wind and solar energy in PJM would drive down the PJM prices.

The impact of more wind and solar energy on average hourly PJM prices are illustrated in Figure 1-24 to Figure 1-27. Figure 1-24 and Figure 1-25 show the PJM LMP Duration Curves for the 20% and 30% scenarios across all levels of prices. Resulting simulation prices, which are fundamentals-cost-based prices, remain below $100/MWh for majority of the hours during the year.

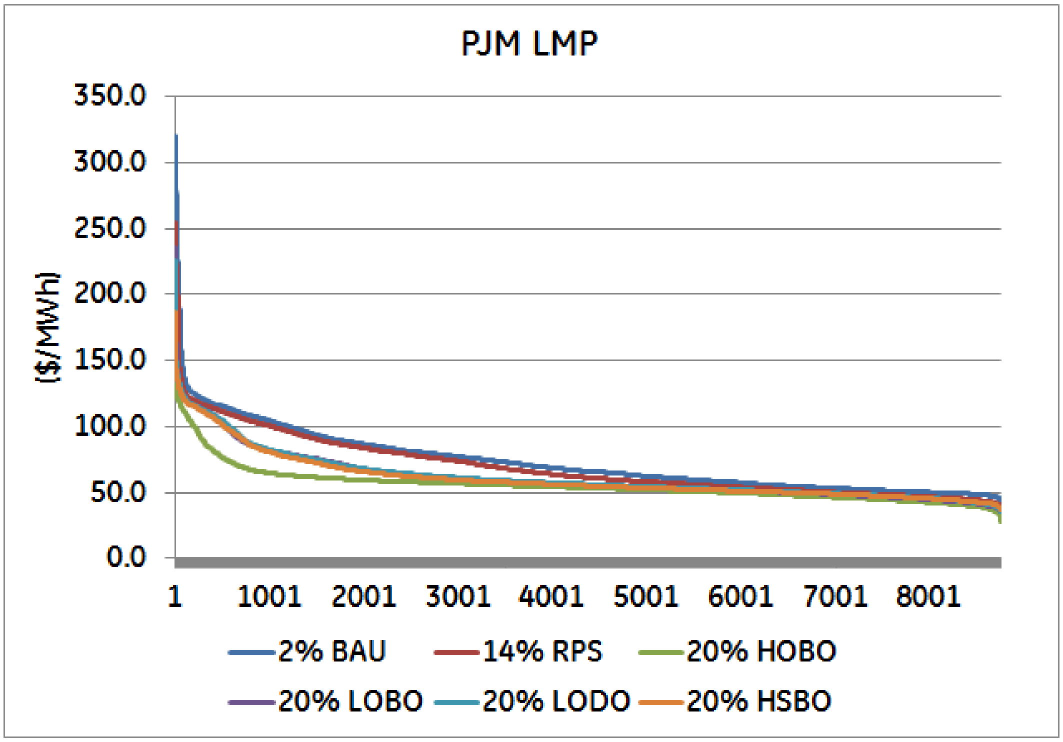

Figure 1-24: PJM LMP Duration Curve (20% Scenarios)

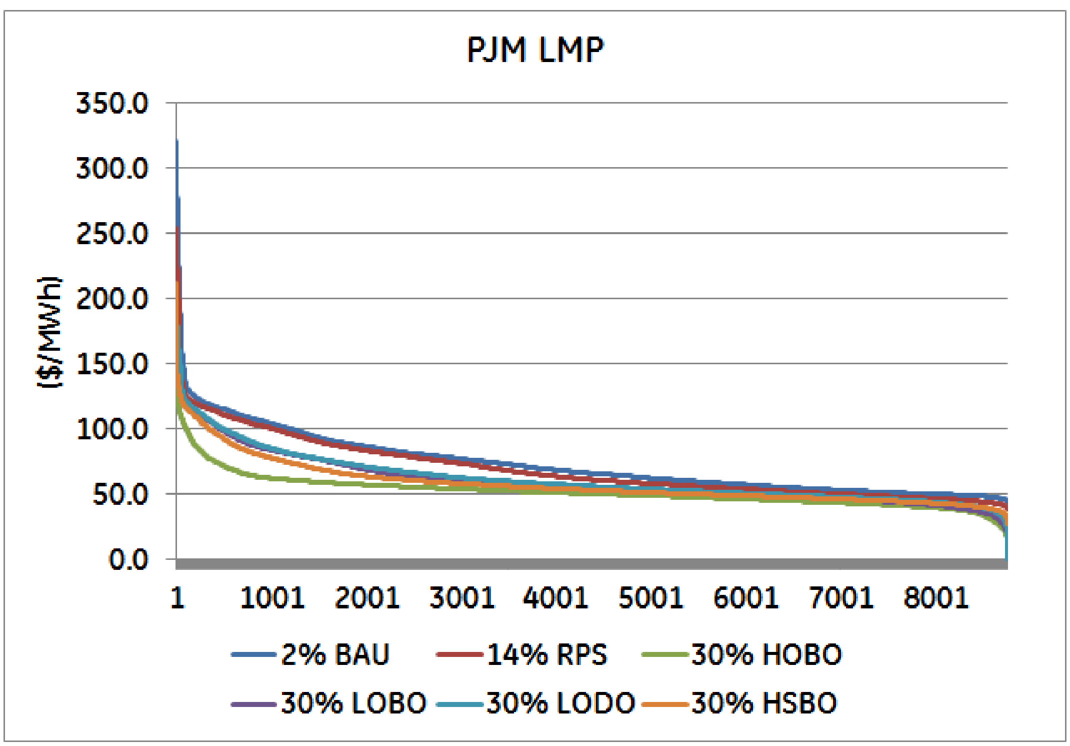

Figure 1-25: PJM LMP Duration Curve (30% Scenarios)

Figure 1-26 and Figure 1-27 zoom on the price levels below $100/MWh to provide more clarity on the relative LMP duration curves across the scenarios.

The order of price levels from highest to lowest are:

1. BAU
2. RPS
3. LODO
4. LOBO
5. HSBO
6. HOBO

The zoomed PJM LMP duration curves show that prices above $100/MWh (the spikes) occur about 1000 hours during the year in the BAU and RPS scenarios. The number of high priced hours drops to a few hundreds in the 20% and 30% scenarios. The HOBO scenarios have the lowest number of hours with prices above $100/MWh.

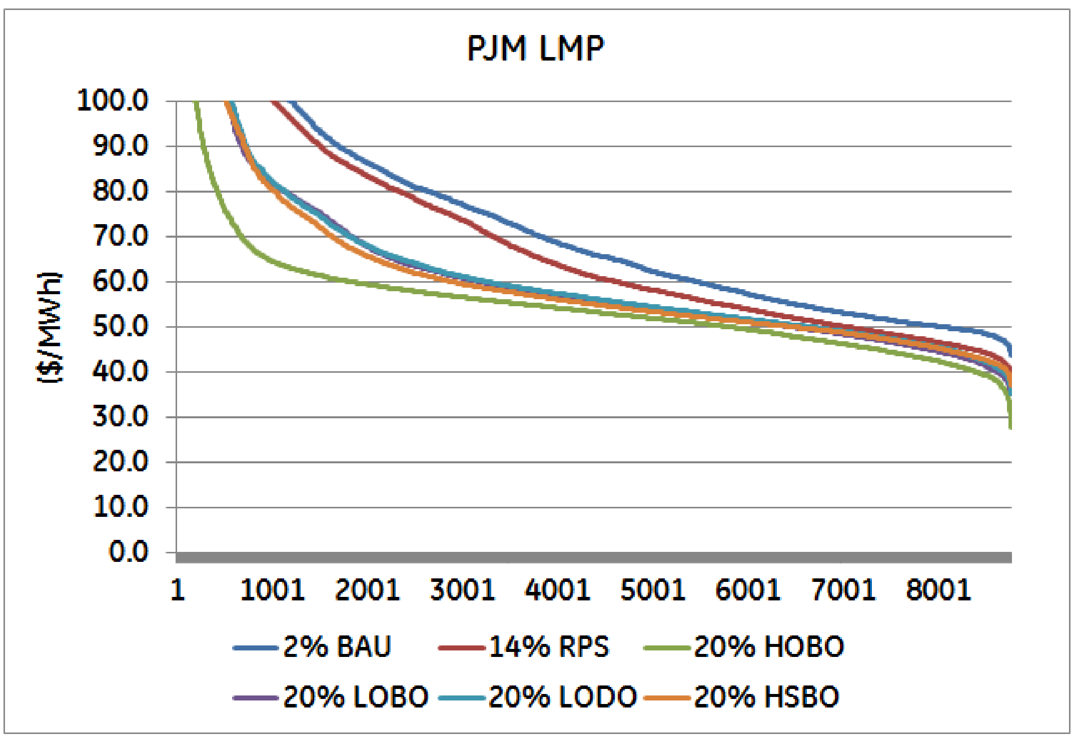

Figure 1-26: PJM LMP Duration Curve during Low Price Hours (20% Scenarios)

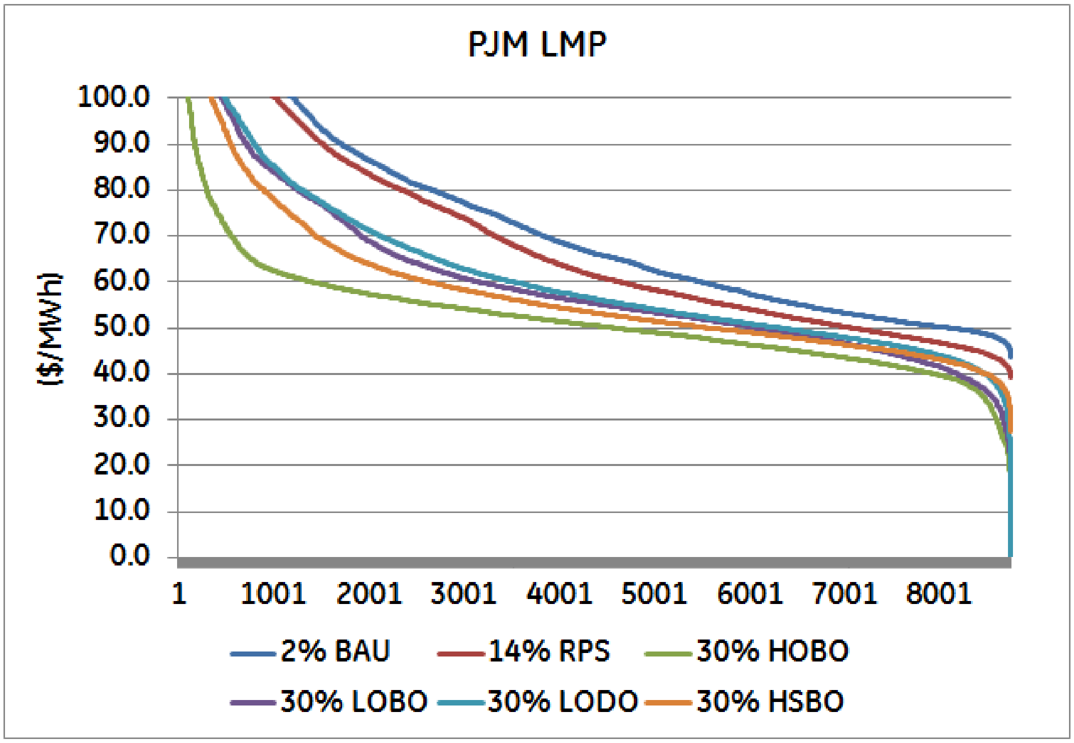

Figure 1-27: PJM LMP Duration Curve during Low Price Hours (30% Scenarios)

Next considered are the LMP prices across PJM areas. In the following figures, PJM Area LMPs are shown, to the extent possible on a one dimensional setting, from West to East and from North to South. Figure 1-28 and Figure 1-29 show the PJM Area All-Hours LMPs across PJM areas. The PJM Area On-Peak LMPs are shown in Figure 1-30 and Figure 1-31. The PJM Area Off-Peak LMPs are shown in Figure 1-32and Figure 1-33.

In cases with renewable penetration above the 2% BAU level, prices jump moving from the most western area in PJM (Commonwealth Edison) and then steady rise moving across PJM ending at the Southeastern region of PJM (Dominion Virginia Power). On the way there are a few locations where some bumpiness are observed, which are most likely due to any lingering local congestion. Congestion can either increase local prices – as in import limited areas, or decrease local prices – as in export limited areas. Different scenarios with different wind and solar resource siting are expected to contribute to relieving or exacerbation of congestion in different ways. The HSBO scenario appears to have big impact on price reduction in two areas: Pennsylvania Electric Company area in 20% scenario, and Delmarva Power & Light area in 30% scenario.

The Delmarva Power & Light area appears to also be impacted in some of the other scenarios, which is likely due to internal transmission transfer capacity limits. Duquesne Light Company area appears to be most impacted by the 30% LODO scenario, which most likely is due to the locally dispersed wind resources.

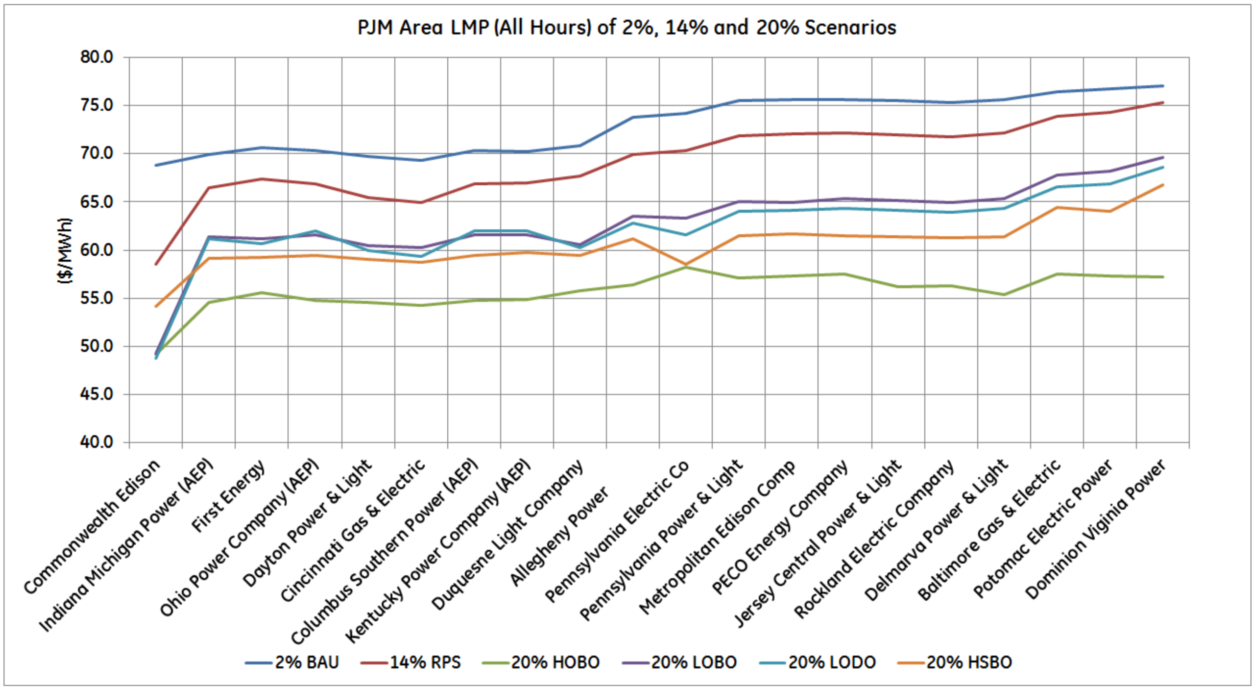

Figure 1-28: PJM LMP by Area for 2%, 14%, and 20% Scenarios (All-Hours)

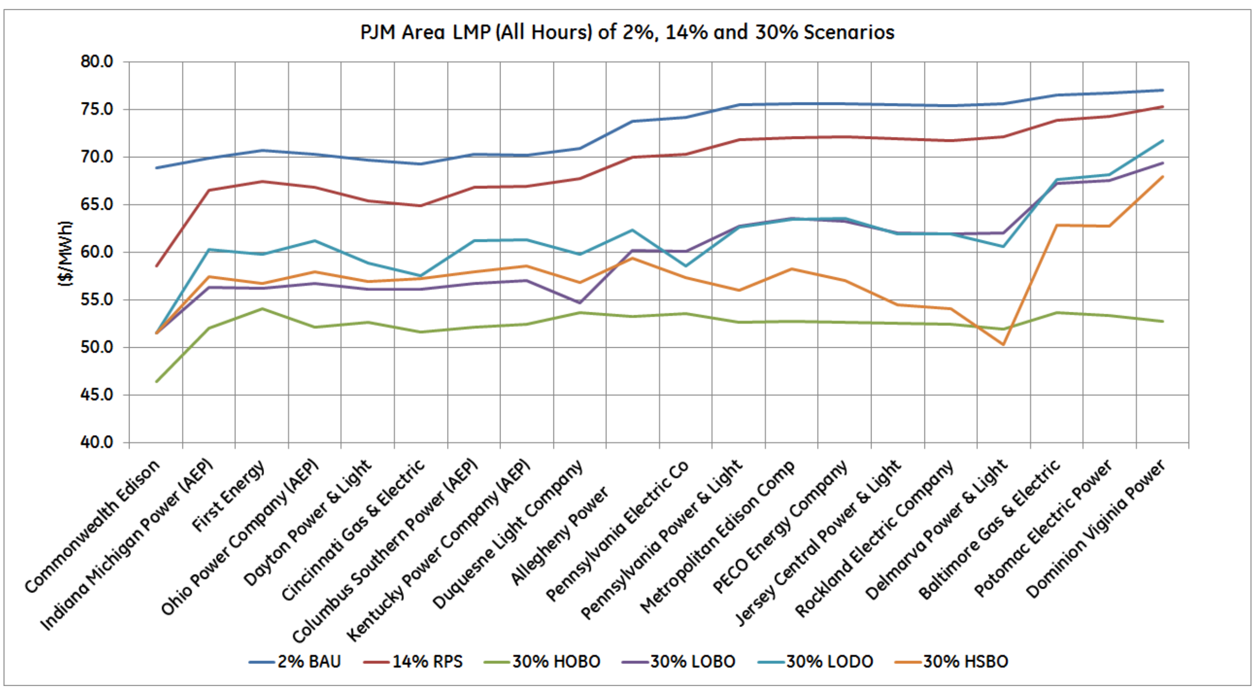

Figure 1-29: PJM LMP by Area for 2%, 14%, and 30% Scenarios (All Hours)

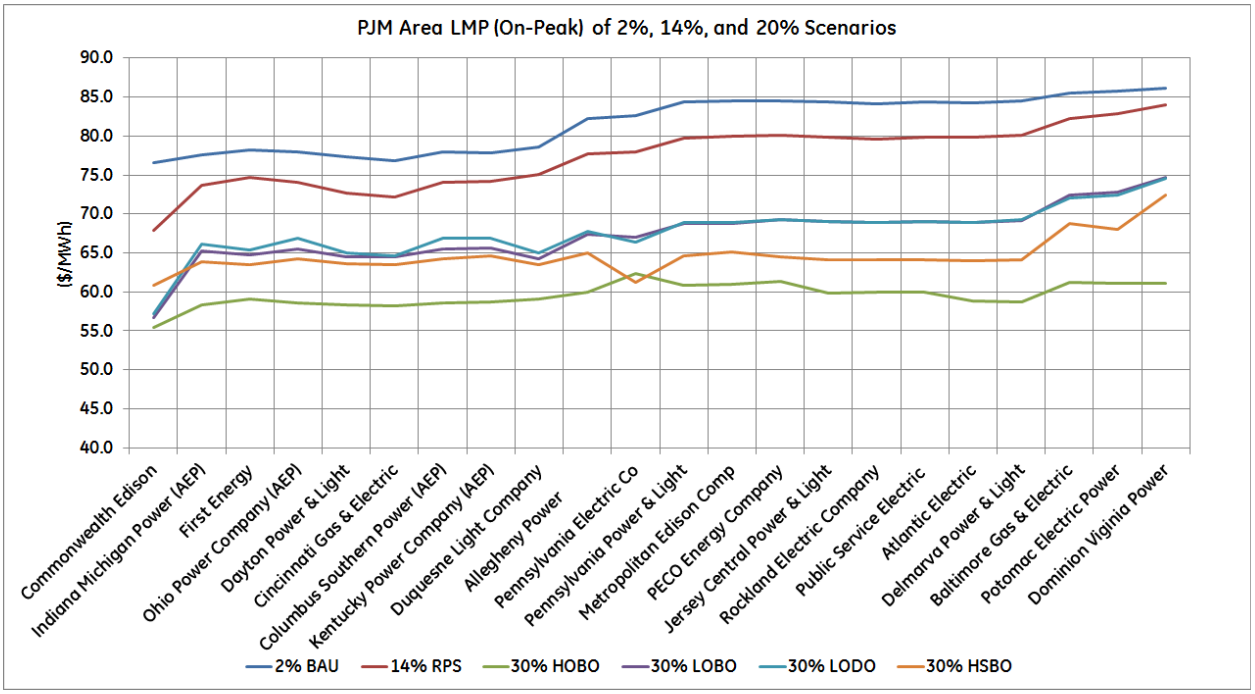

Figure 1-30: PJM LMP by Area for 2%, 14%, and 20% Scenarios (On-Peak)

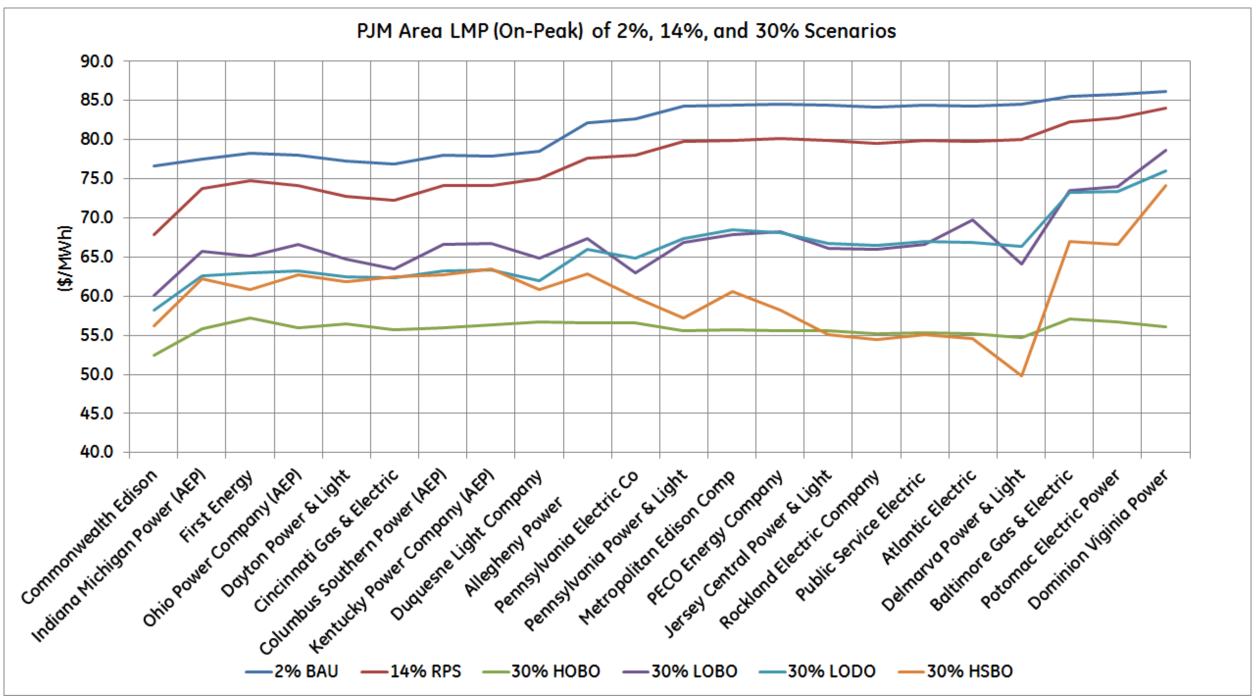

Figure 1-31: PJM LMP by Area for 2%, 14%, and 30% Scenarios (On-Peak)

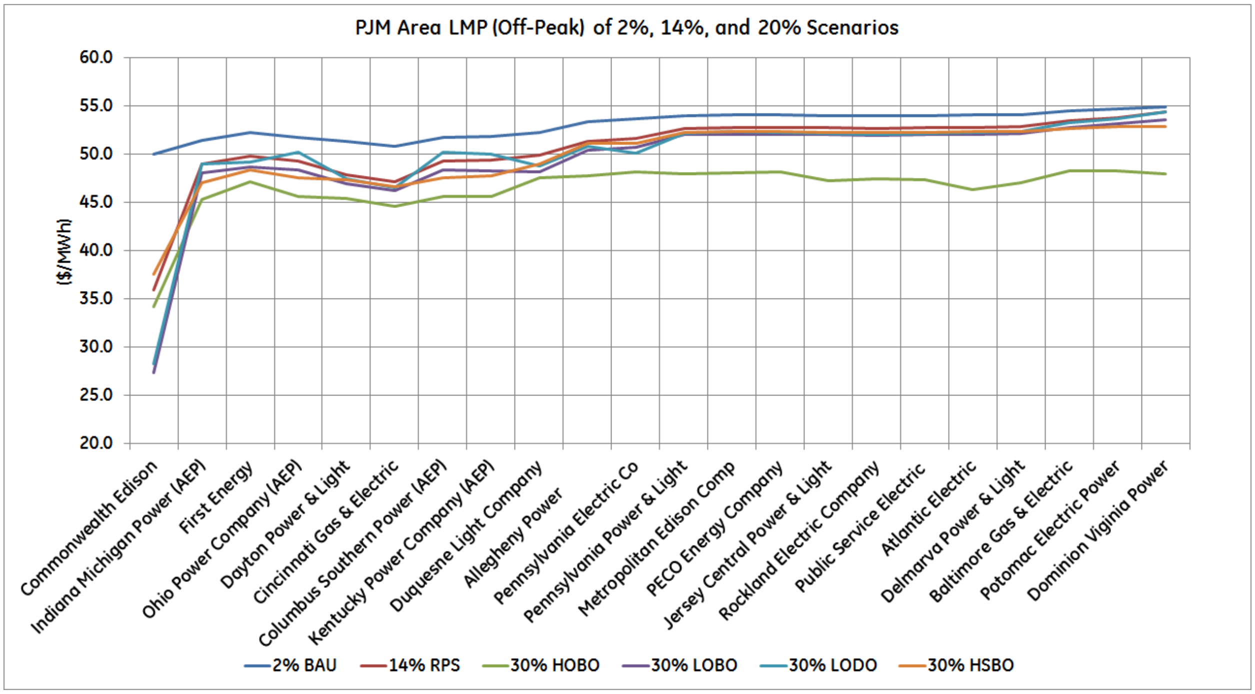

Figure 1-32: PJM LMP by Area for 2%, 14%, and 20% Scenarios (Off-Peak)

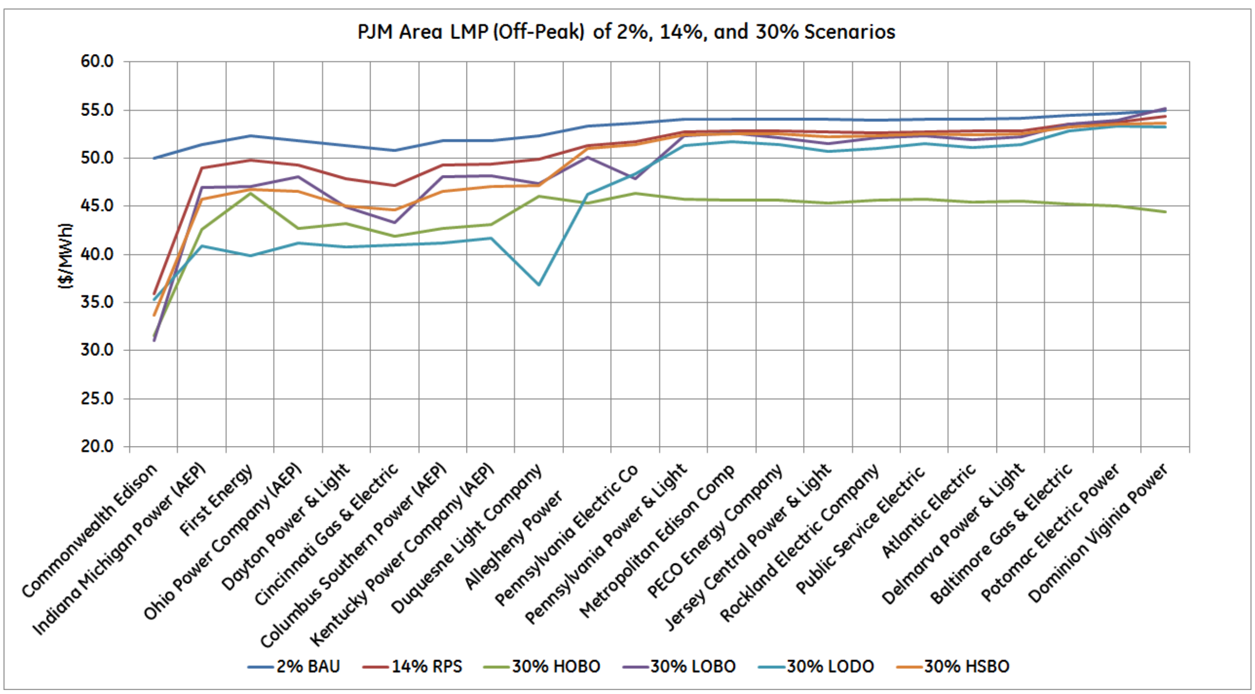

Figure 1-33: PJM LMP by Area for 2%, 14%, and 30% Scenarios (Off-Peak)

1.6 Economic Performance

Concomitant with lowering of thermal generation, higher penetration of renewable resources are expected to lower the system production (variable) costs. This is seen in Figure 1-34 and Figure 1-35, where PJM system production costs drop progressively with higher levels of renewable energy penetration. PJM system production costs in this report refer to the annual total of fuel costs, VOM costs, emission costs (but not modeled in the base scenarios where emission allowance costs were set to zero), and any start-up costs. Production costs do not include any fixed costs or PPA costs of IPP wind and solar energy.

The 20% and 30% LODO scenarios appear to have the least impact on production costs compared to the other high renewable penetration scenarios, which is most likely due to the relatively dispersed nature of the onshore wind locations which on average not as good as the best wind locations selected for the other scenarios.

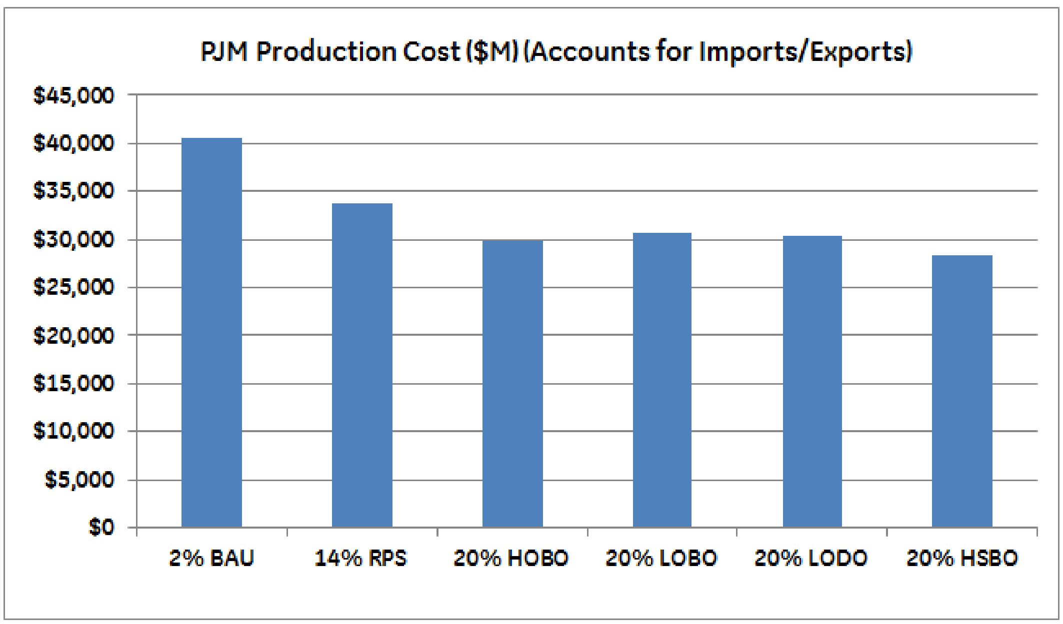

Figure 1-34: PJM Production (Variable) Costs (20% Scenarios)

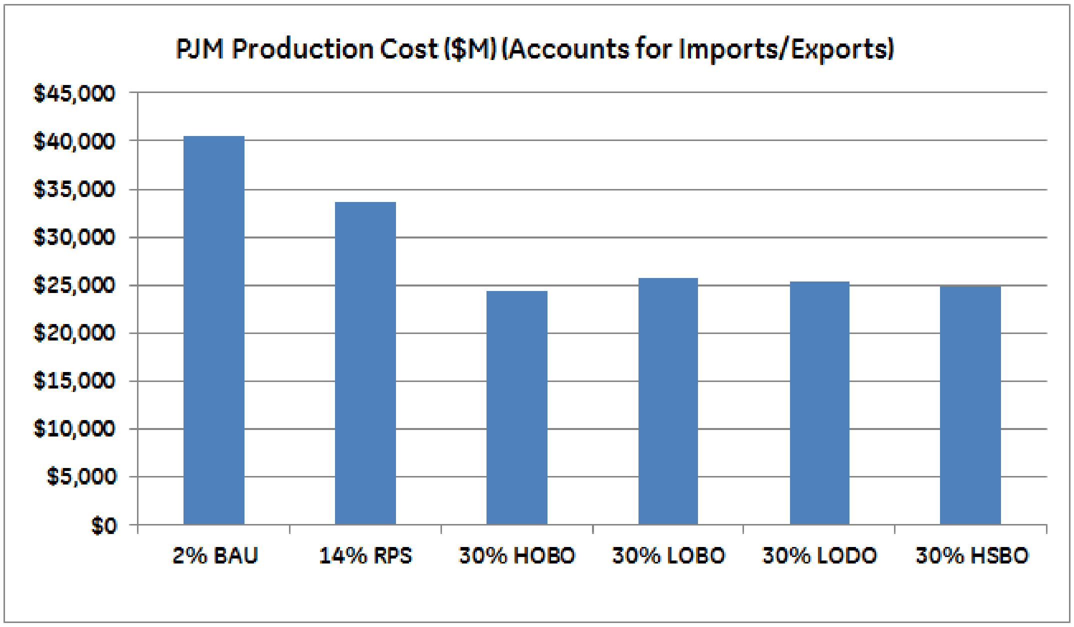

Figure 1-35: PJM Production (Variable) Costs (30% Scenarios)

The reduction in thermal generation also impacts the generator revenues. Generator gross revenues are impacted by both the amount of generation, and also the location specific LMP of each generator. Reduction in thermal generation, as shown in following sections, also results in reduction of LMP across most areas of PJM. The generator gross revenues are calculated by summing up - across all hours of the year - the hourly products of each plant's electricity generation (in MWh) by the hourly LMP at the plant location (in $/MWh).

The overall impact can be seen in Figure 1-36 and Figure 1-37. The HOBO scenarios have the greatest impact on lowering of PJM generator gross revenues in both 20% and 30% scenarios. It was previously shown that the LOBO scenarios resulted in the largest reduction in coal based generation, whereas the CCGT generation were most impacted by the HOBO scenarios. It was also shown earlier that the HOBO scenarios also have the greatest impact on the PJM prices, and hence help drive the generator gross revenues more than the other scenarios.

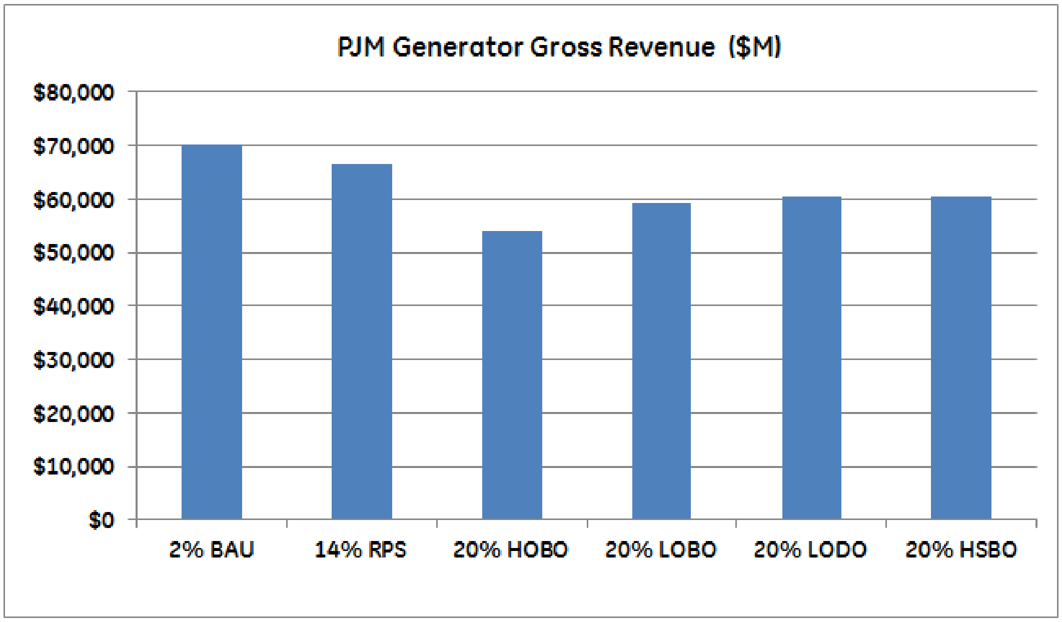

Figure 1-36: PJM Generator Gross Revenues (20% Scenarios)

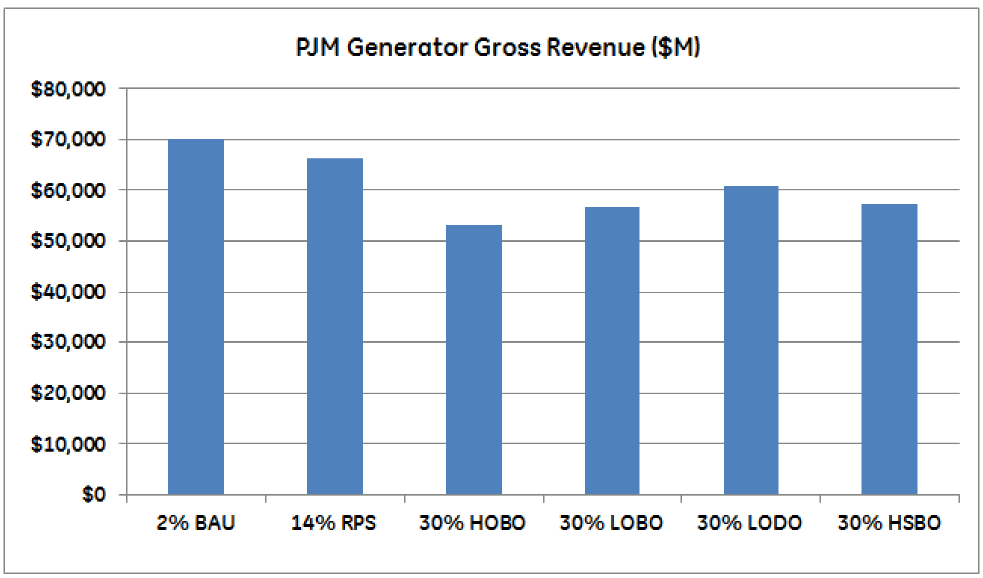

Figure 1-37: PJM Generator Gross Revenues (30% Scenarios)

Lower prices also translate to lower PJM costs to serve load. The PJM Wholesale Customer Energy Cost is calculated by summing up - across all hours of the year - the products of the hourly load in each zone (in MWh) by the hourly zonal prices (in $/MWh). Hourly zonal price in each zone is the load-weighted average of hourly LMP across each zone.

Similarly to the generator gross revenues, it can be seen that the HOBO scenarios also result in lowest PJM Wholesale Customer Energy Cost in comparison to the other scenarios, which is consistent with their impact on lowering the PJM prices.

It should be noted that the discussion of lower wholesale customer energy costs only applies to the wholesale customer payments for the energy portion of the zonal prices. The evaluated zonal prices do not include other system cost components and results should not be interpreted as the all-in cost for rate payers.

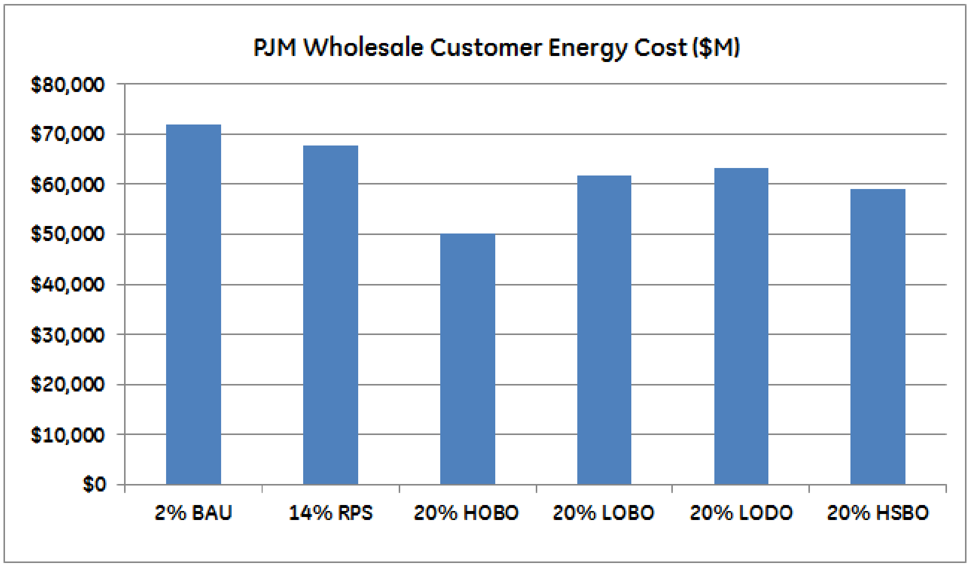

Figure 1-38: PJM Wholesale Customer Energy Cost (20% Scenarios)

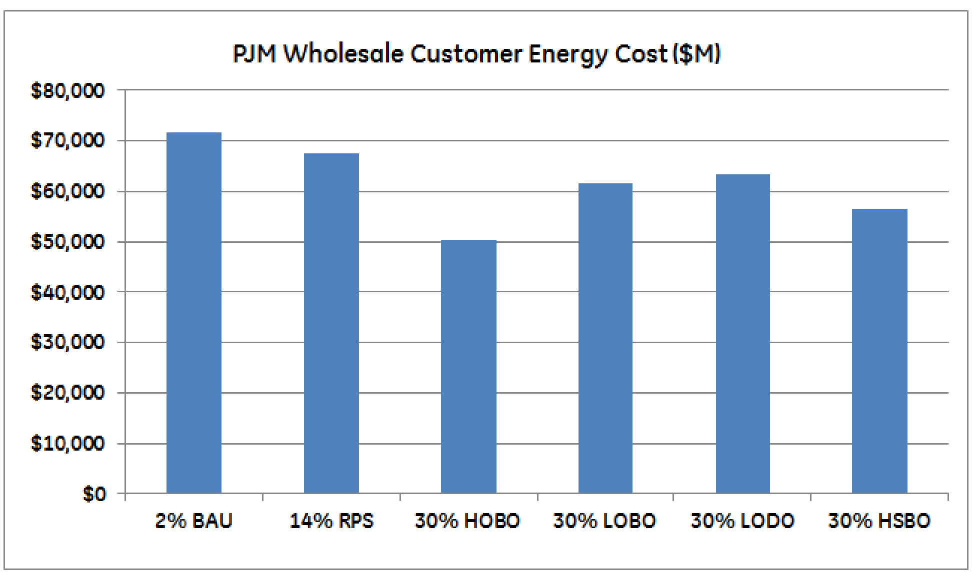

Figure 1-39: PJM Wholesale Customer Energy Cost (30% Scenarios)

1.7 Key Impacts of Renewables on Annual PJM Operations

The results of the hourly GE MAPS simulations show the following impacts of higher wind and solar energy penetration on the PJM grid:

- Lower Coal and CCGT generation under all scenarios. Wind and solar resources are effectively price-takers and therefore displace more expensive generation resources.
- Lower emissions of criteria pollutants and greenhouse gases, due to reduced operation of thermal generation resources.
- No unserved load and minimal renewable energy curtailment. There were no operating conditions where wind/solar variability or uncertainty caused an insufficiency of generation. Nearly all of the wind and solar energy was used to serve load.
- Lower system-wide production costs (i.e., fuel costs for thermal generators)
- Lower gross revenues for conventional generation resources
- Lower average LMP and zonal prices across the PJM grid

Figure 1-40 illustrates how the energy dispatch shifts from gas and coal generation to renewable resources as the renewable penetration increases. The upper plot shows the progression to 20% penetration and the lower plot extends to 30% penetration of wind and solar energy. On average for all scenarios, about 36% of the renewable energy displaces coal-based generation about 39% displaces gas-fired generation, as compared to the 2% BAU Scenario.

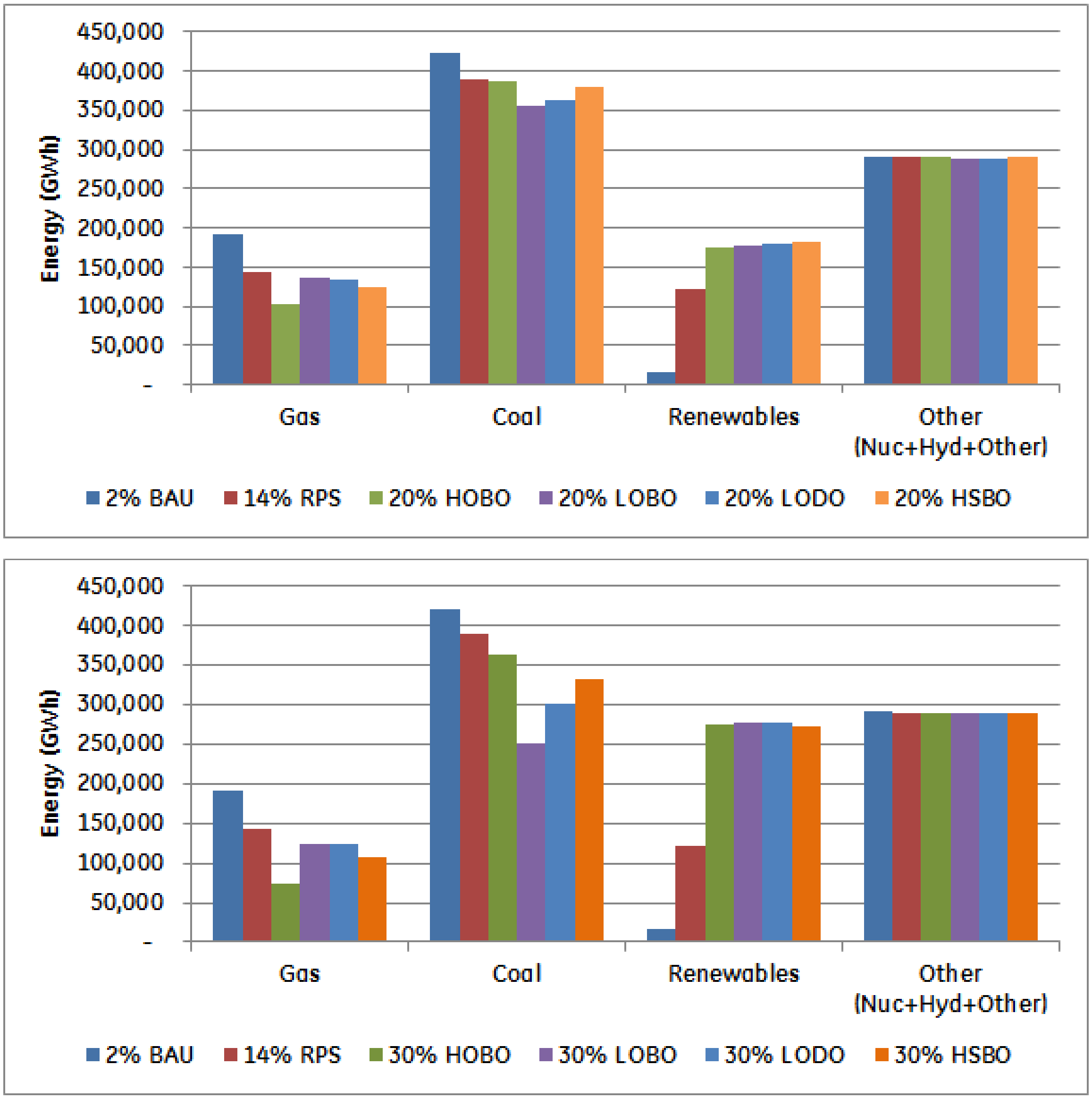

Figure 1-40: Annual Energy Production by Unit Type for Study Scenarios

Table 1-2 shows how several economic and energy parameters are affected by increased renewables in the study scenarios. Changes are measured relative to the 2% BAU scenario. In the 14% RPS scenario, 47% of the additional renewable energy displaces gas-fired resources and 31% displaces coal. In several of the 20% and 30% scenarios, proportionately more coal energy is displaced.

Table 1-2: Key Findings of the Hourly Production Cost Modeling

Scenario	Renewable Energy Delivered (GWh)	Production Cost ($B)	Wholesale Load Payments Delta ($B)	Gas Delta (GWh)	Coal Delta (GWh)	Imports Delta (GWh)	Gas Displacement (%)	Coal Displacement (%)	Reduced Imports (%)
2% BAU	17,217	40.5	71.8	192,025	421,618	47,390	0%	0%	0%
	Delta Relative to 2% BAU Scenario								
14% RPS	105,642	-6.8	-4.2	-49,590	-32,866	-21,397	-47%	-31%	-20%
20% HOBO	157,552	-10.6	-21.5	-90,194	-34,604	-31,302	-57%	-22%	-20%
20% LOBO	160,490	-9.9	-10.1	-56,854	-66,940	-32,267	-35%	-42%	-20%
20% LODO	161,542	-10.1	-8.6	-58,322	-59,647	-41,085	-36%	-37%	-25%
20% HSBO	164,253	-12.1	-12.7	-66,682	-42,505	-53,696	-41%	-26%	-33%
30% HOBO	256,400	-16.1	-21.5	-118,876	-58,453	-77,631	-46%	-23%	-30%
30% LOBO	259,428	-14.8	-10.1	-68,192	-170,920	-19,134	-26%	-66%	-7%
30% LODO	259,345	-15.1	-8.6	-68,013	-119,526	-68,653	-26%	-46%	-26%
30% HSBO	253,918	-15.6	-15.3	-84,511	-88,847	-78,382	-33%	-35%	-31%
Average							-39%	-36%	-24%

- This study did not evaluate potential impacts on PJM Capacity Market results due to reduced generator revenues from the wholesale energy market, nor did it evaluate the impact of renewables to rate payers. It is conceivable that lower energy prices would be at least partially offset by higher capacity prices.
- Production Cost is sum of Fuel Costs, Variable O&M Costs, Any Emission Tax/Allowance Cost, and Start-Up Costs.

Figure 1-41 shows several annual operational trends for the study scenarios. Compared to the 2% BAU scenario,

- Coal and CCGT capacity factors decline with increasing renewables
- CCGT annual starts remain the same for the 14% RPS scenario and double for many of the 20% and 30% scenarios, indicating an increase in cycling duty. Annual starts for coal plants increase slightly, indicating that there are periods of the year when some coal plants are not committed.
- Net energy revenues for CCGT and coal plants decline significantly with increasing renewables.
- Most of the new renewable energy is used to serve load and only a small portion must be curtailed in the 20% and 30% scenarios, mostly due to local congestion.

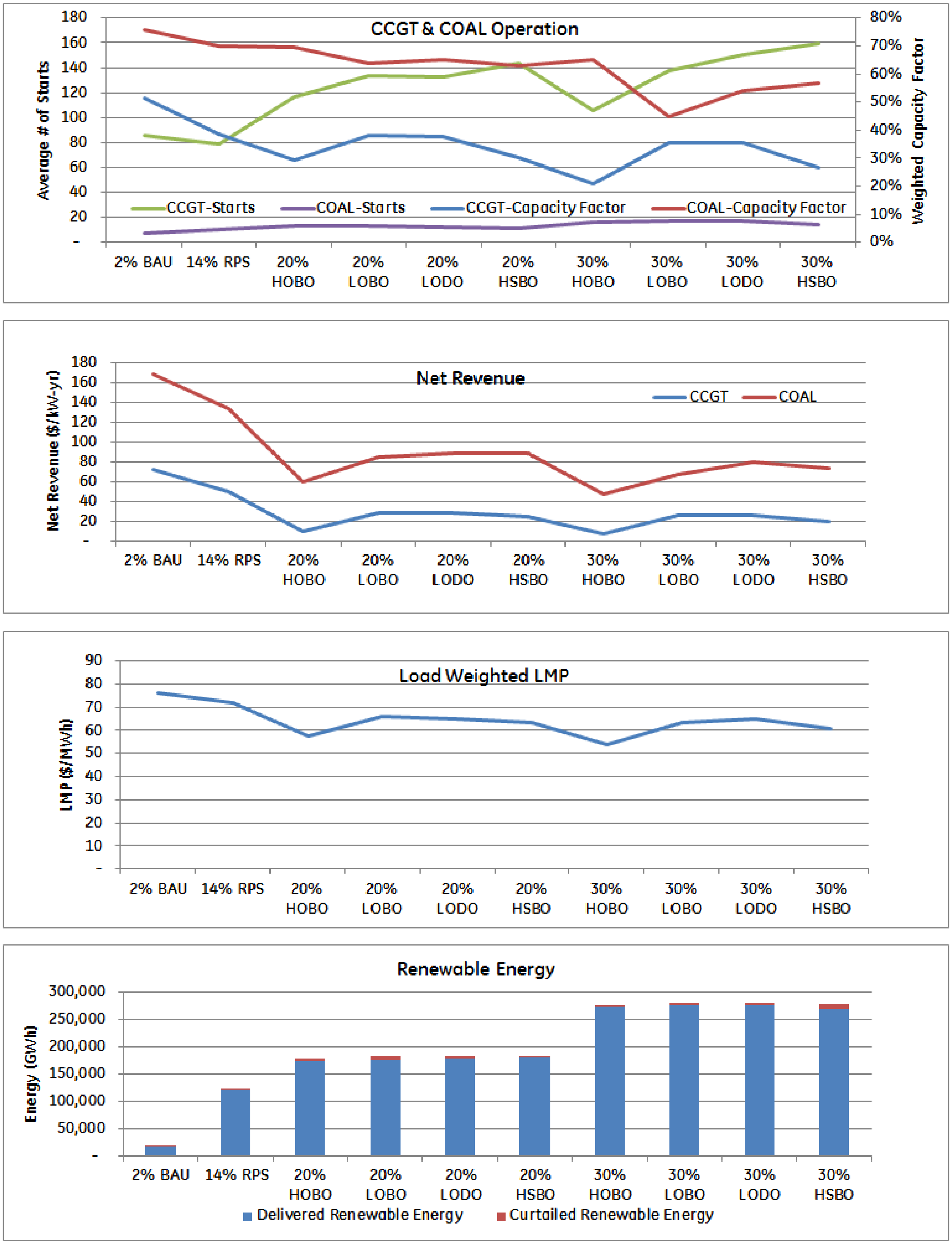

Figure 1-41: PJM Annual Operation Trends for Study Scenarios

Figure 1-42 shows trends in total PJM production costs and transmission expansion/upgrade costs as a function of renewable penetration level. Production costs are fairly similar for all scenarios with the same renewable energy penetration. Transmission costs are similar for all 20% penetration scenarios but dramatically different for the 30% scenarios. The 30% LOBO scenario includes a high concentration of wind power in the western PJM region, and significant transmission upgrades are needed to transport that wind energy to load centers. In the LODO scenario, wind resources are more dispersed across the PJM footprint, so the wind plants are closer to load centers.

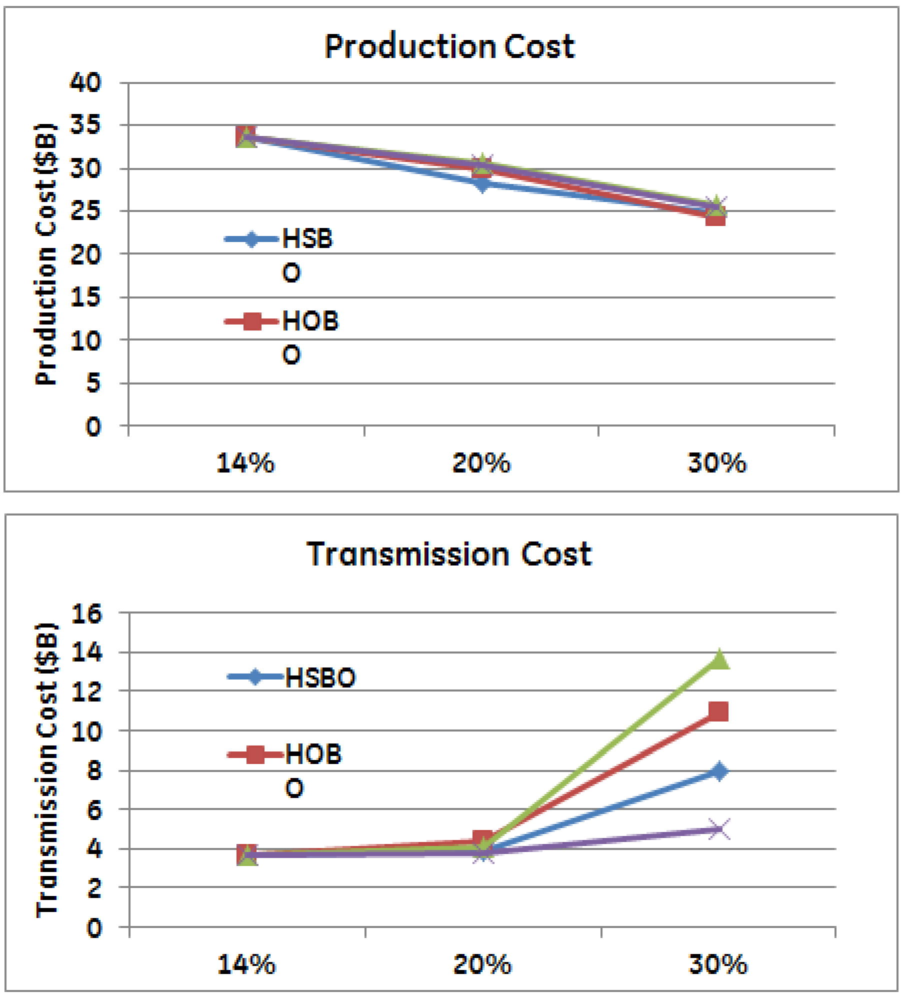

Figure 1-42: Trends in Production Costs and Transmission Costs versus Renewable Penetration

1.8 Contribution of Renewables to Lowering Production Costs

One interesting question is the contribution, on a per MWh basis, of the additional renewable energy to the reduction in PJM production costs. Figure 1-43 and Figure 1-44 illustrate the impact relative to the 2% BAU scenario, showing the average impact of most scenarios somewhere between \$57/MWh RE to \$74/MWh RE (where RE stands for Renewable Energy) of additional wind. These values do not factor in any fixed costs of renewable energy development, IPP power purchase costs, and any costs of needed additional transmission. It should be noted that these are "average" contributions to lowering of production costs associated with the impact of total amount of renewable energy, and not the "marginal" value associated with the last MWh of renewable energy.

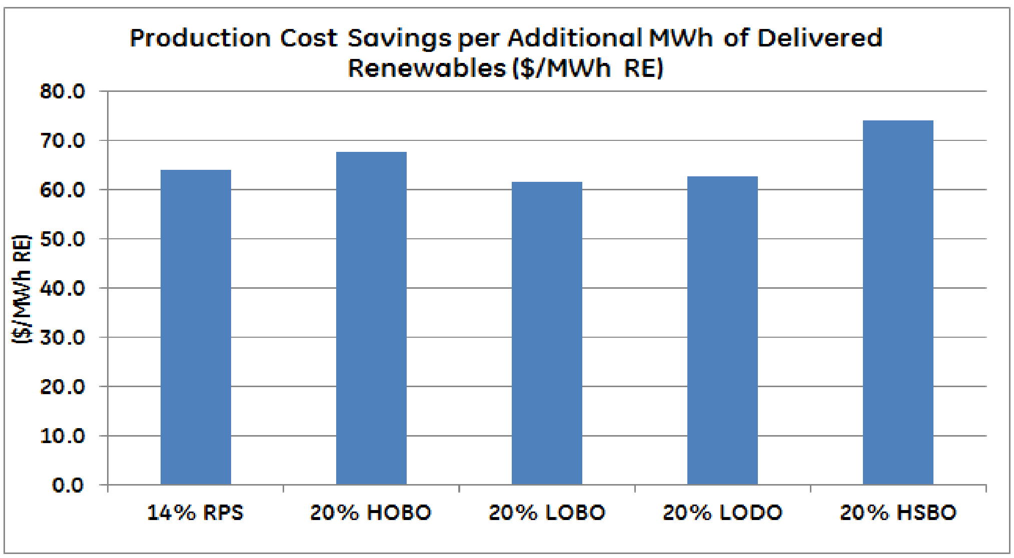

Figure 1-43: Production Cost Savings over 2% Scenario per MWh Renewable Additions (20% Scenarios)

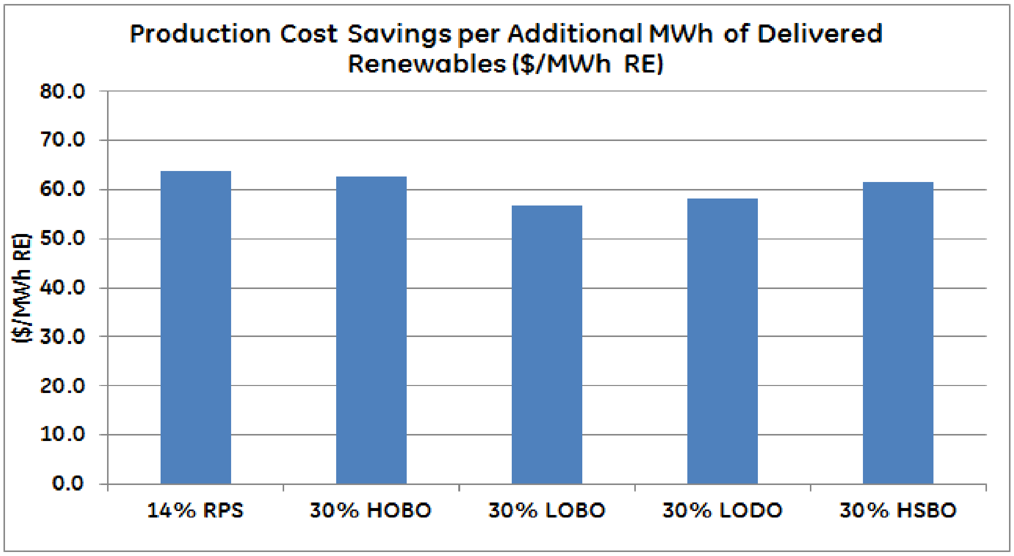

Figure 1-44: Production Cost Savings over 2% Scenario per MWh Renewable Additions (30% Scenarios)

Variations in values across scenarios reflect, to some extent, the different transmission configurations (i.e., expansion plans) applied in each scenario. Hence, the comparison across scenarios is somewhat hampered due to the differences in transmission configuration in each scenario.

To isolate the transmission impacts, the following two tables look at the value of the renewables accounting for the transmission cost for each scenario. Both tables take into account the transmission costs reported in the main table of the Section on Transmission Analysis.

In Table 1-3 shows the impact of renewable energy in production cost savings in each of the study scenarios. The value is calculated as the reduction in PJM annual production cost divided by the increase in delivered renewable energy, relative to the 2% BAU scenario. The right-hand column shows the production cost savings of the renewables adjusted for the estimated annualized cost of transmission upgrades. The range of production cost savings due to renewable energy ranges from $56 to $74 per MWh of Renewable Energy based on production costs alone, and $49 to $71 per MWh of Renewable Energy if estimated costs for transmission upgrades are included. As noted before, Production Cost is sum of Fuel Costs, Variable O&M Costs, any Emission Tax/Allowance Costs, and Start-Up Costs – adjusted by adding Imports Costs and subtracting Export Sales. A carrying charge of 15% was used to calculate the annualized transmission cost from total estimated capital costs.

Table 1-3: Renewable Contribution to Lowering Production Cost

Scenario	Renewable Energy Delivered (GWh) over the 2% BAU Scenario (GWh)	Production Cost Savings over the 2% BAU Scenario ($B/Year)	Production Cost Savings per MWh of Delivered Renewables ($/MWh RE)	Annualized Transmission Costs ($M/Year)	Transmission Costs per MWh of Delivered Renewables ($/MWh RE)	Production Cost Savings Adjusted for Transmission Costs ($/MWh RE)
14% RPS	105,642	-6.8	63.9	555	4.5	59.4
20% HOBO	157,552	-10.6	67.4	660	3.8	63.7
20% LOBO	160,490	-9.9	61.4	615	3.5	58.0
20% LODO	161,542	-10.1	62.6	570	3.2	59.4
20% HSBO	164,253	-12.1	73.8	585	3.2	70.6
30% HOBO	256,400	-16.1	62.7	1,635	6.0	56.8
30% LOBO	259,428	-14.8	56.9	2,055	7.4	49.5
30% LODO	259,345	-15.1	58.1	750	2.7	55.4
30% HSBO	253,918	-15.6	61.6	1,200	4.4	57.2

2 Comparison of Different Profile Years

2.1 Operational Performance Comparisons

As noted previously, most of the analysis was based on using load, wind energy, and solar energy shapes patterns (or hourly patterns) from 2006. The hourly patterns where then scaled up for the 2026, the study year. This section considers the question of how the analysis results are changed if a different base profile year is used for the analysis, by comparing results of simulations using 2004, 2005, & 2006 historical load and renewable shapes for the 2026 study year.

Also as noted previously, it is important to use load and renewable energy profiles from the same year in order to maintain any correlation between load and renewable energy patterns. The methodology for constructing the load and renewable energy patterns for 2026 from a base profile year are described in the Task 1 Report. The analysis was performed for the 2% BAU, 14% RPS, 20% LOBO, and 30% LOBO scenarios.

Following figures display the variation in generation by unit type for the selected scenarios.

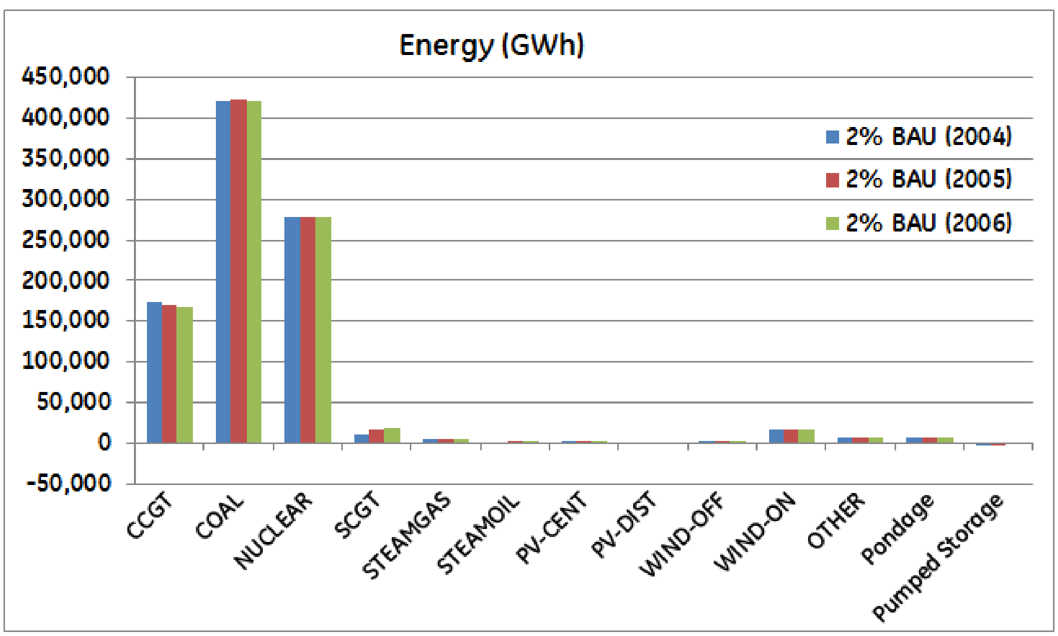

Figure 2-1: Variation in Generation by Unit Type under Different Profile Years (2% BAU Scenario)

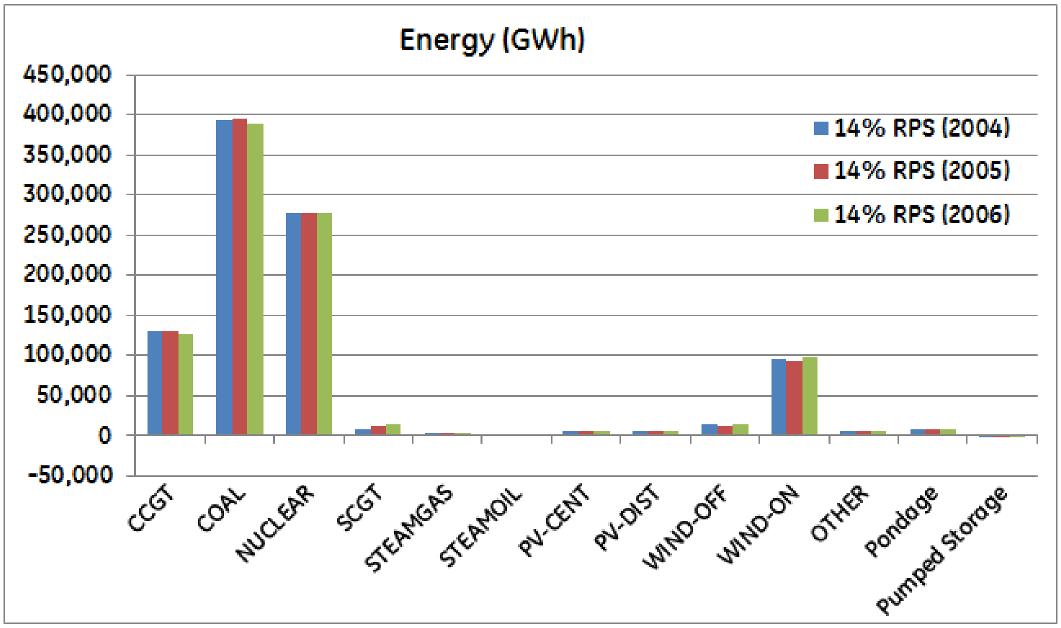

Figure 2-2: Variation in Generation by Unit Type under Different Profile Years (14% RPS Scenario)

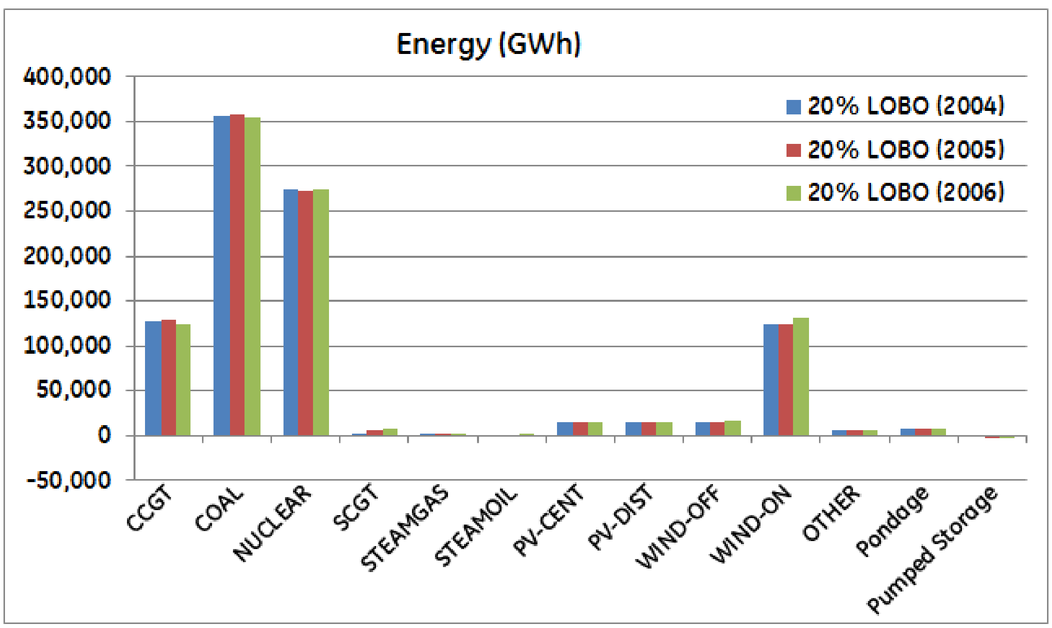

Figure 2-3: Variation in Generation by Unit Type under Different Profile Years (20% LOBO Scenario)

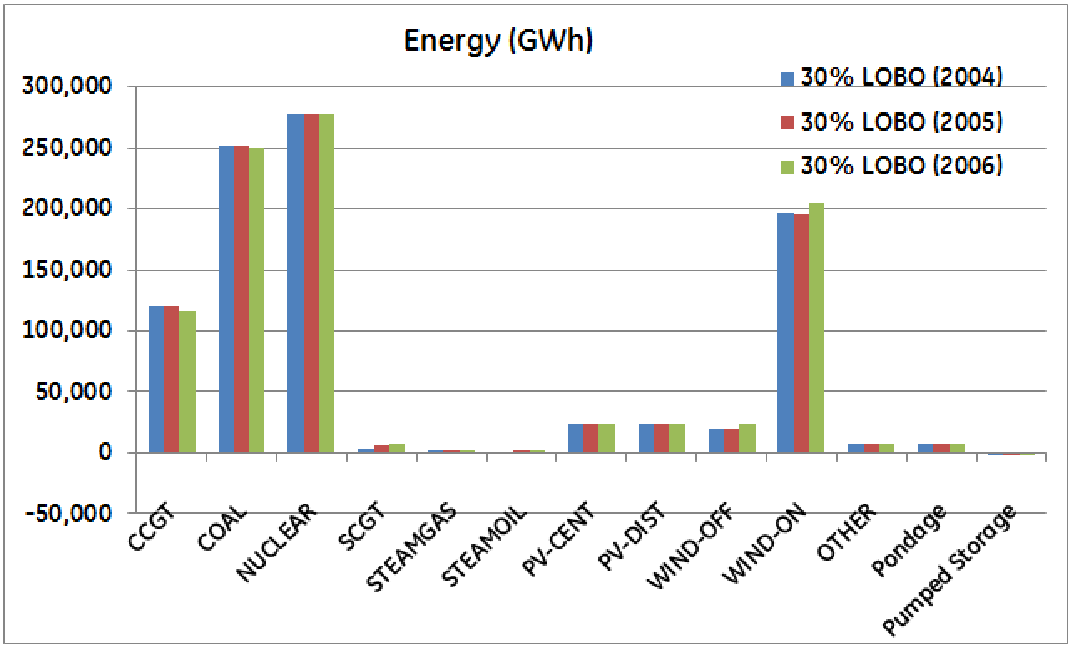

Figure 2-4: Variation in Generation by Unit Type under Different Profile Years (30% LOBO Scenario)

Very little variation in generation by type is observed, except that 2006 appears to be a higher wind generation year, which in higher wind penetration years (i.e., 20% and 30% scenarios) forces down generation by CCGT and coal units. Higher wind penetration and its associated intermittency and volatility results in higher SCGT utilization. The 2004 and 2005 profile years are more similar compared to the 2006 profile year. The 2004 profile year demonstrates a slightly higher wind generation than the 2005 profile year.

Following figures depict the delivered renewable energy as percent of PJM load.

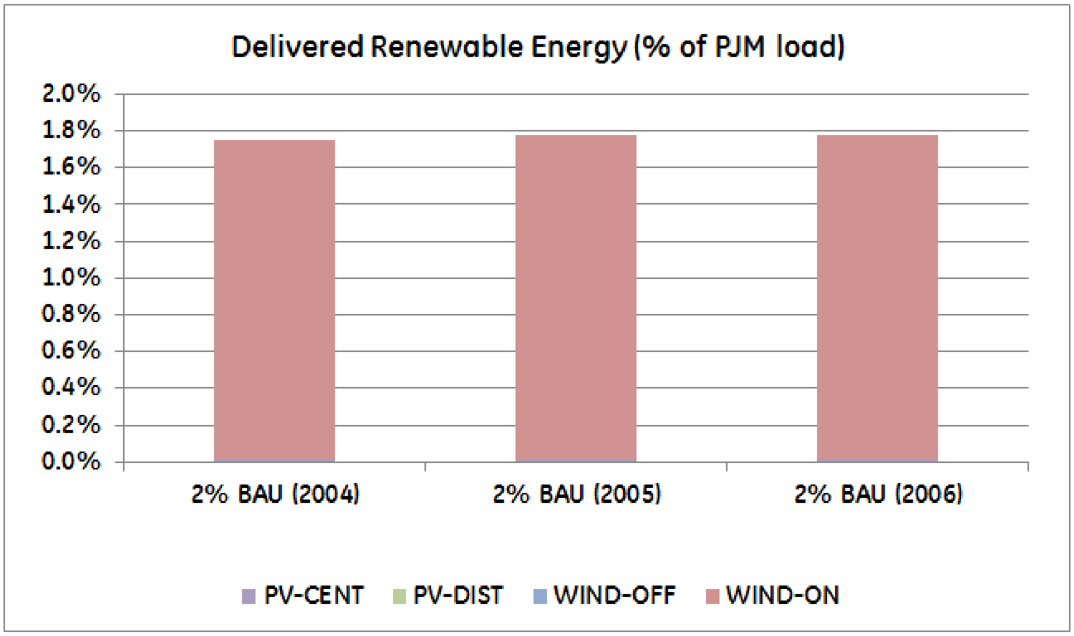

Figure 2-5: Renewable Energy as % of PJM Load under Different Profile Years (2% BAU Scenario)

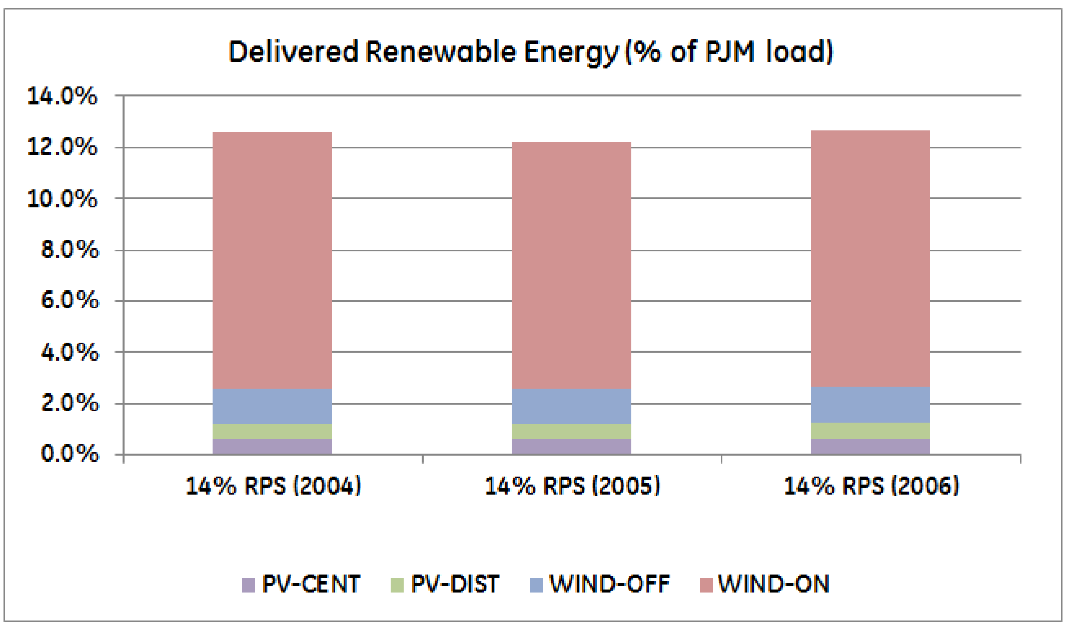

Figure 2-6: Renewable Energy as % of PJM Load under Different Profile Years (14% RPS Scenario)

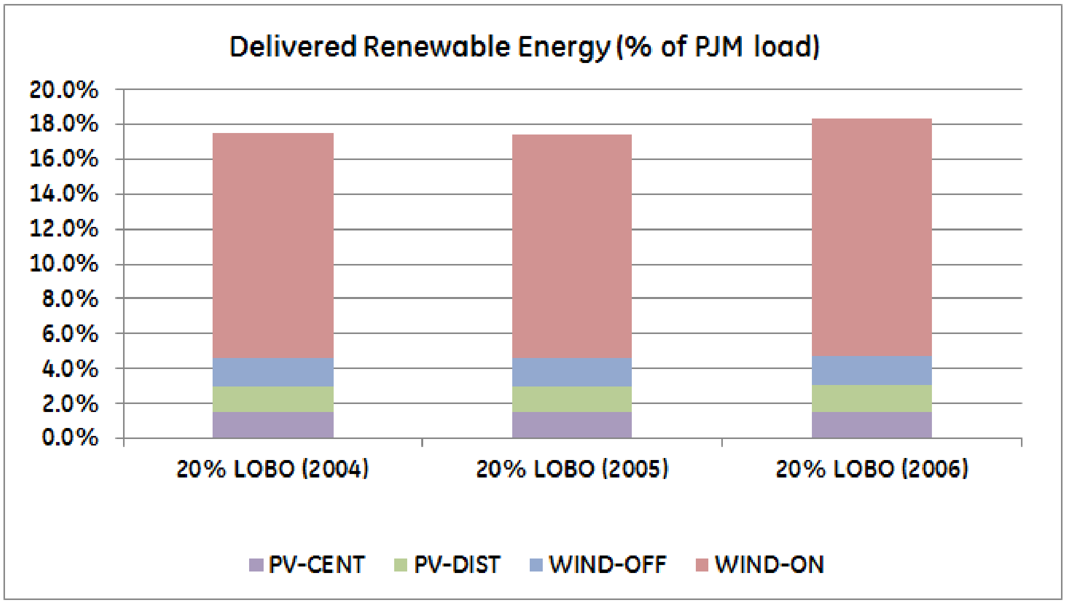

Figure 2-7: Renewable Energy as % of PJM Load under Different Profile Years (20% LOBO Scenario)

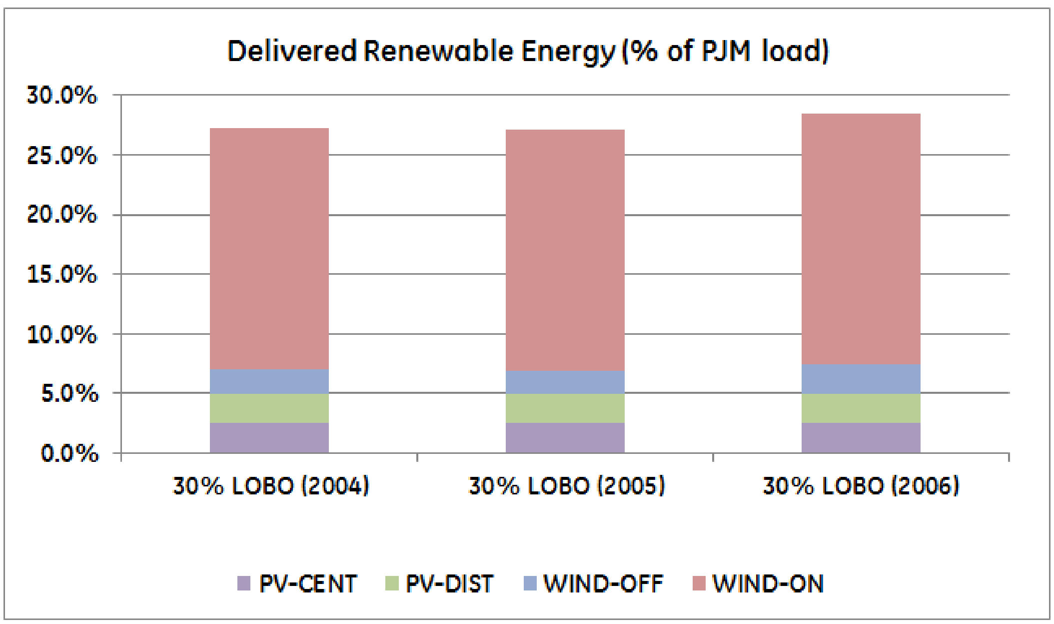

Figure 2-8: Renewable Energy as % of PJM Load under Different Profile Years (30% LOBO Scenario)

Again, these figures illustrate the fact that the 2006 profile year is a higher wind energy year compared to the 2004 and 2005 profile years, for both onshore and offshore wind.

Following figures show the capacity factor of selected unit types under different profile years.

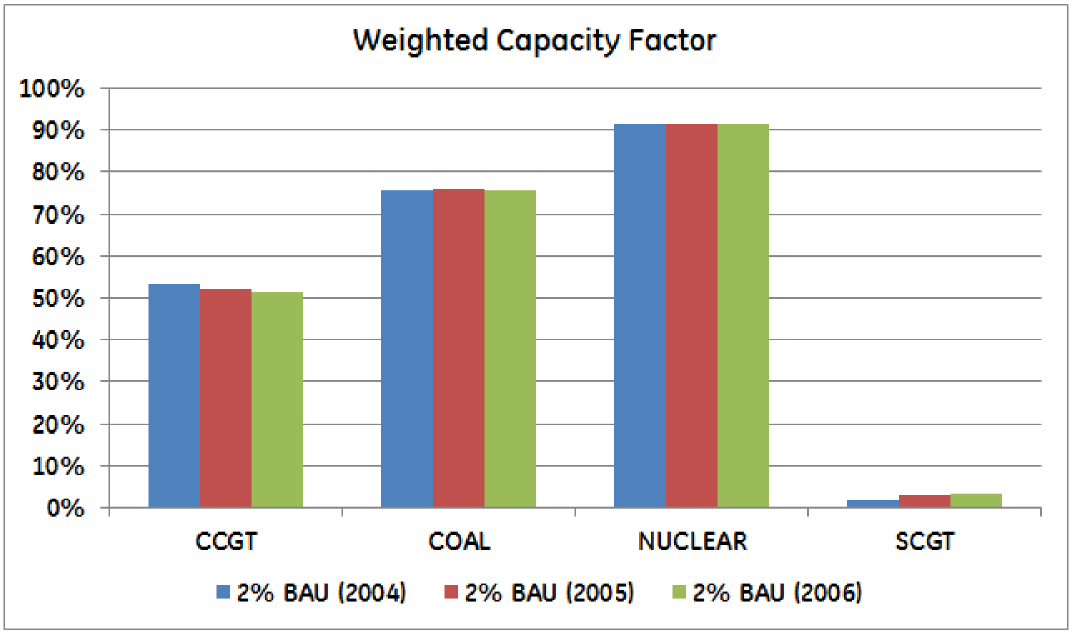

Figure 2-9: Weighted Capacity Factor by Unit Type under Different Profile Years (2% BAU Scenario)

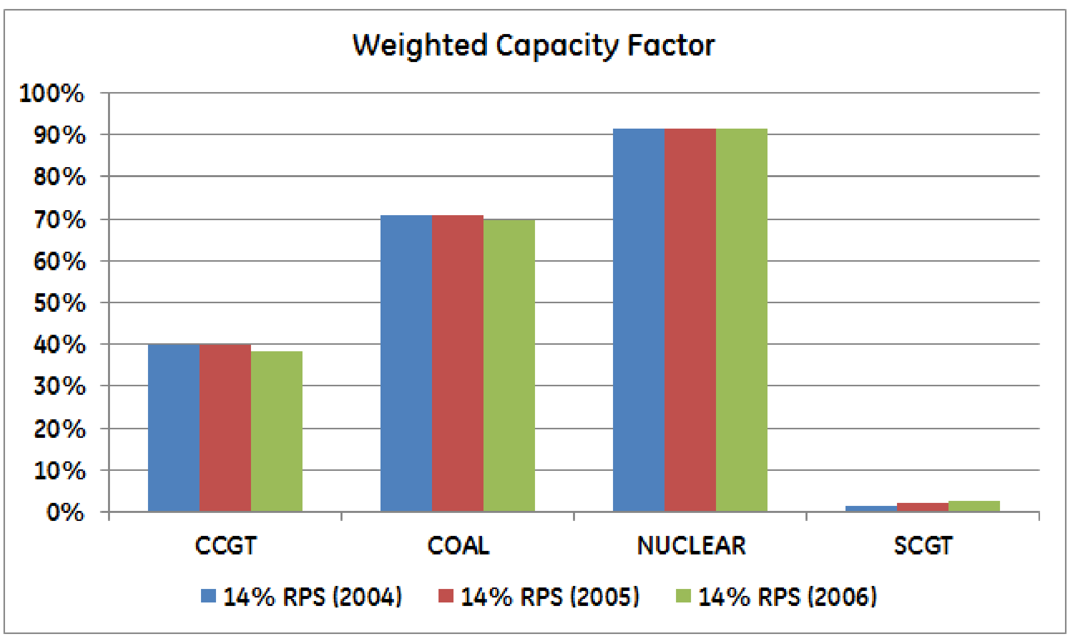

Figure 2-10: Weighted Capacity Factor by Unit Type under Different Profile Years (14% RPS Scenario)

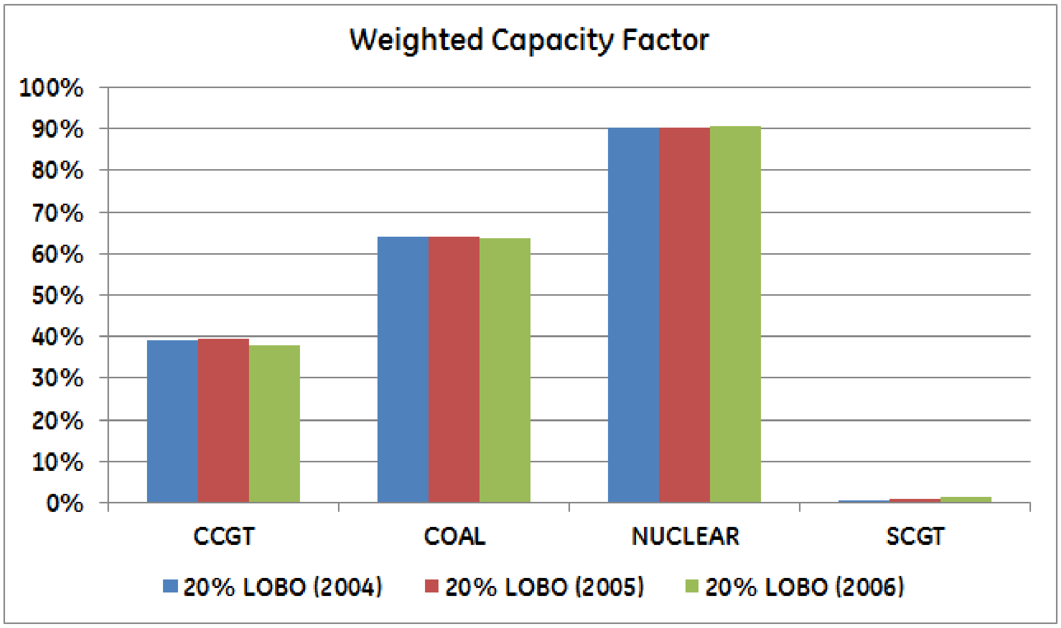

Figure 2-11: Weighted Capacity Factor by Unit Type under Different Profile Years (20% LOBO Scenario)

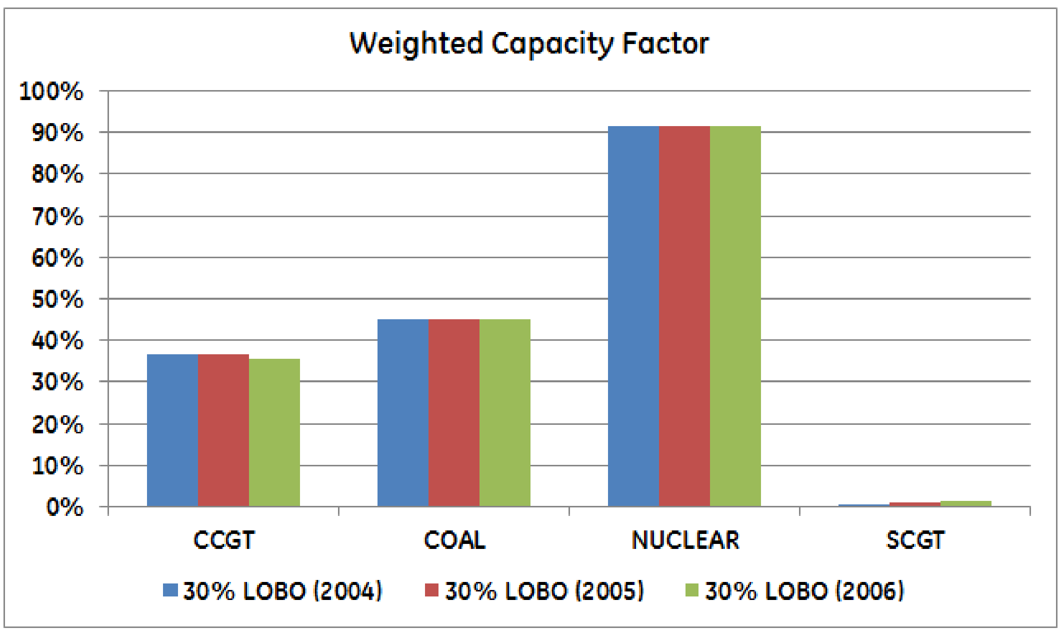

Figure 2-12: Weighted Capacity Factor by Unit Type under Different Profile Years (30% LOBO Scenario)

As expected, there is a slight decrease in the capacity factor of CCGT and coal units in the higher penetration rates, and in contrast, there is slight increase in capacity factor of SCGT units.

Following figures illustrate the relative environmental and GHG emissions under the three base profile years.

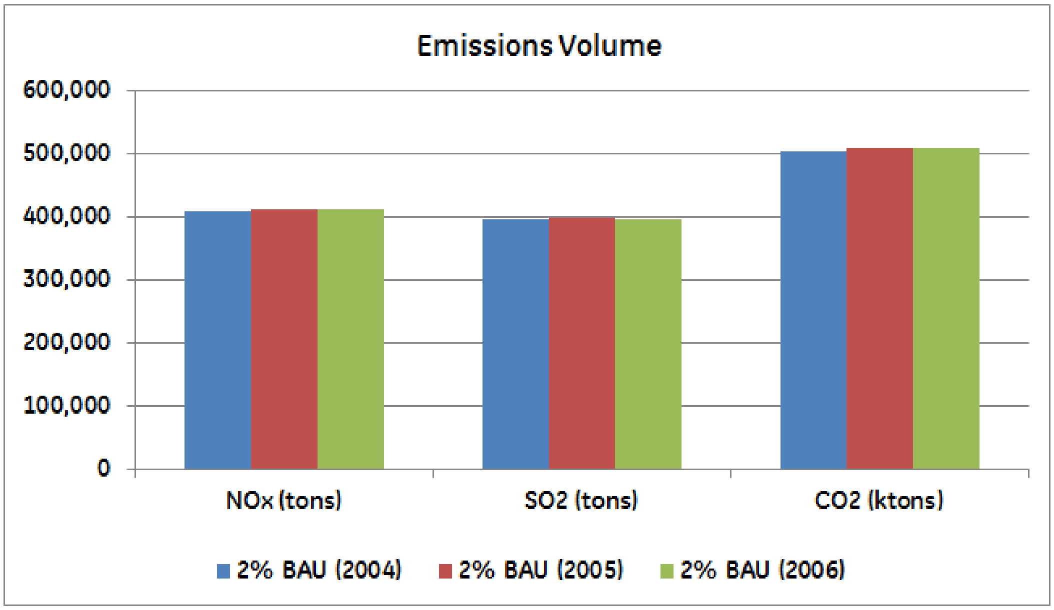

Figure 2-13: Emissions Volume under Different Profile Years (2% BAU Scenarios)

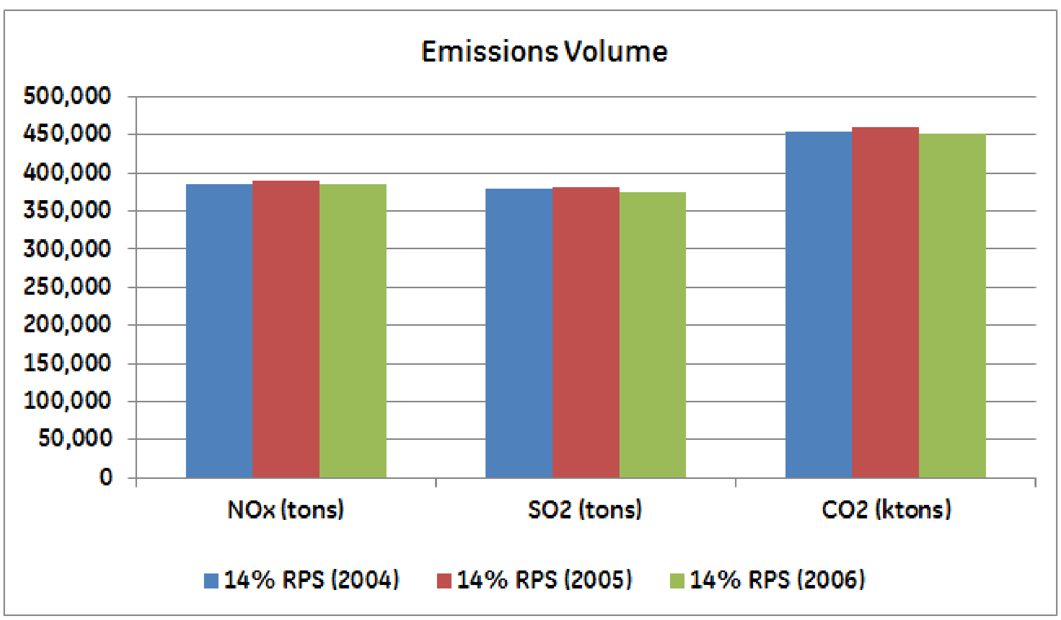

Figure 2-14: Emissions Volume under Different Profile Years (14% RPS Scenarios)

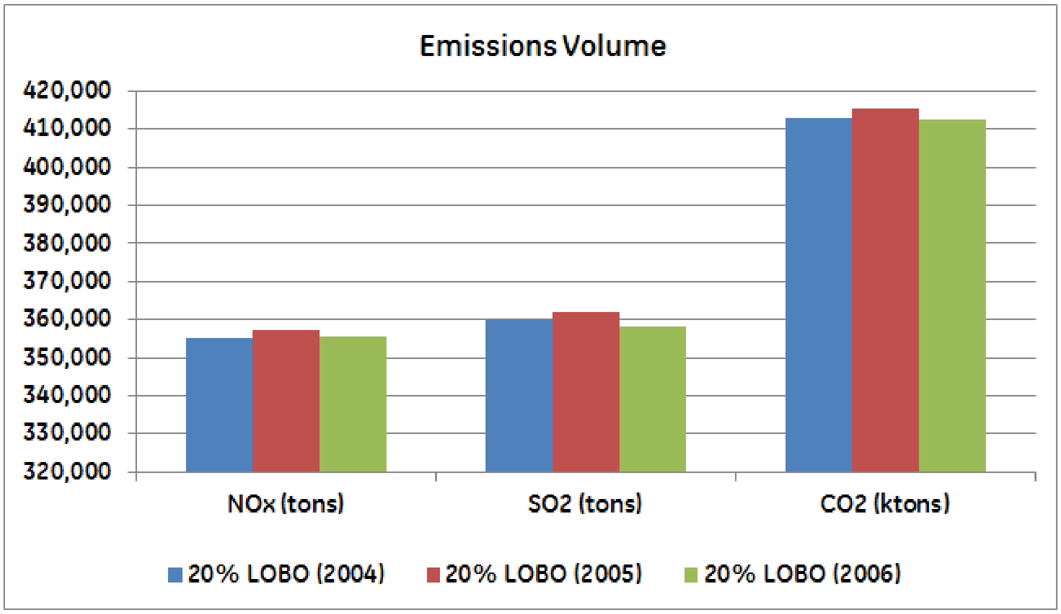

Figure 2-15: Emissions Volume under Different Profile Years (20% LOBO Scenarios)

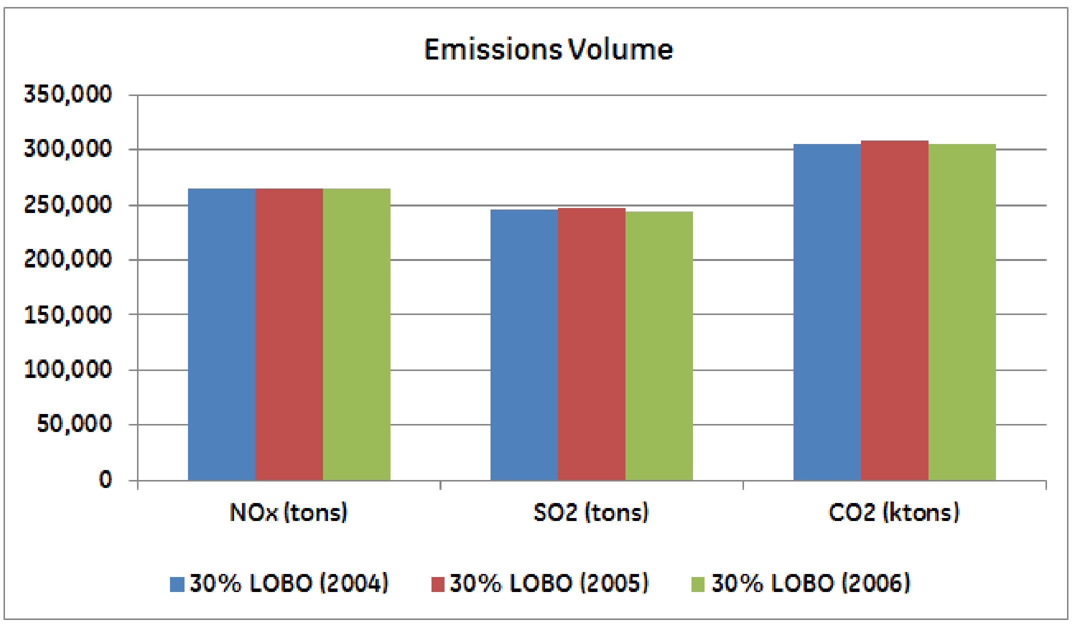

Figure 2-16: Emissions Volume under Different Profile Years (30% LOBO Scenarios)

As expected, environmental emissions drop in 2006 compared to the other profile years due to decrease in CCGT and Coal generation. Emissions are also lower in 2004 compared to 2005, again due to relatively higher generation of CCGT and Coal in 2004.

Overall, using different profile years only makes a slight difference in overall system level performance metrics such as energy generation by unit types and environmental emission levels. The differences are derived by the relative amount of renewable energy in different profile years. For the profile years considered, the differences do not appear to be huge and are not expected to impact the overall results of the study. The only major exception is the capacity value of wind (and solar?), which is discussed further in the LOLE and Wind Capacity Valuation section.

2.2 Unit Type Behavior

Following figures illustrate the variation in performance by each unit type under different profile years for selected scenarios.

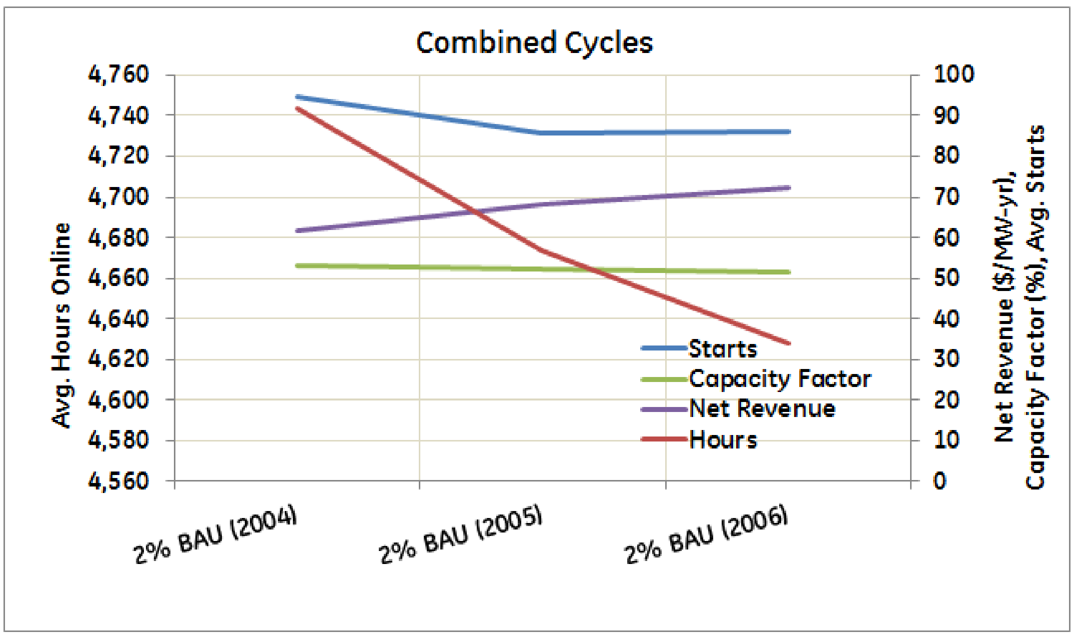

Figure 2-17: Variation in Performance of CCGT units under Different Profile Years (2% BAU Scenario)

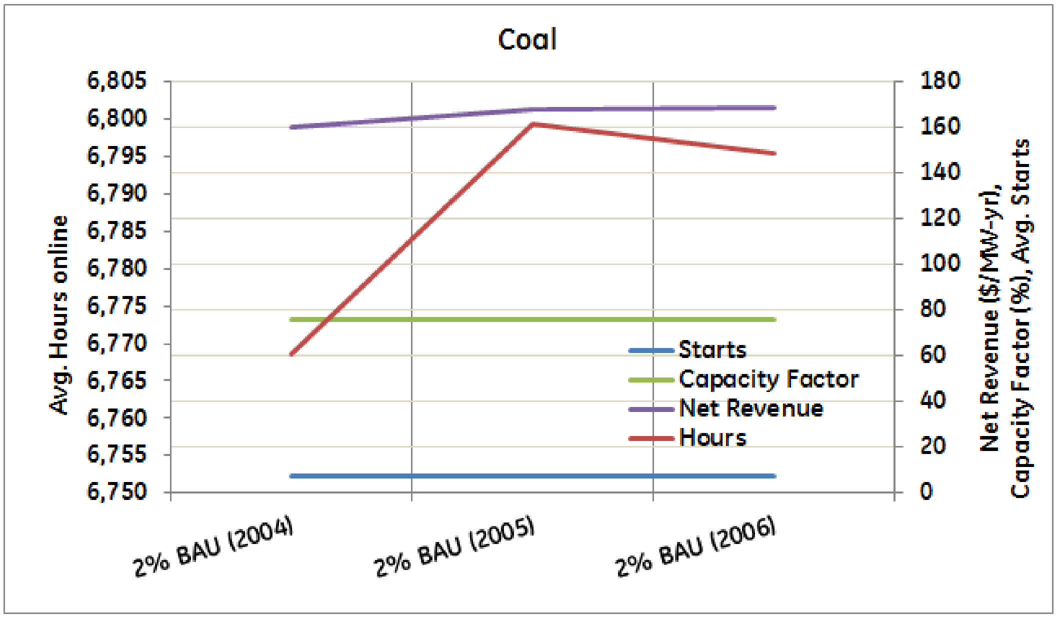

Figure 2-18: Variation in Performance of Coal units under Different Profile Years (2% BAU Scenario)

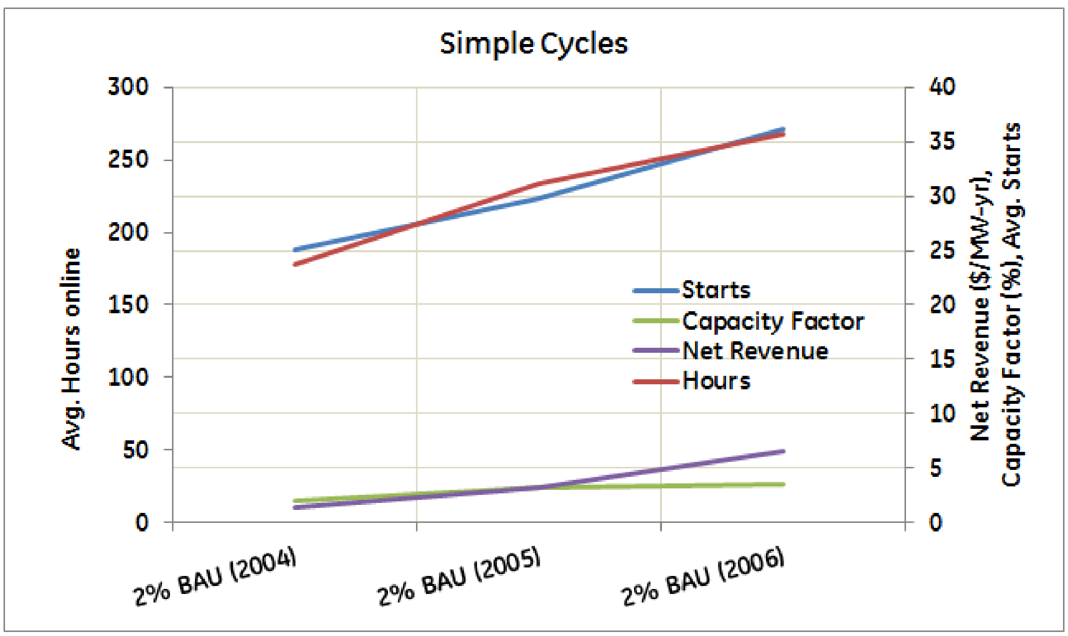

Figure 2-19: Variation in Performance of SCGT units under Different Profile Years (2% BAU Scenario)

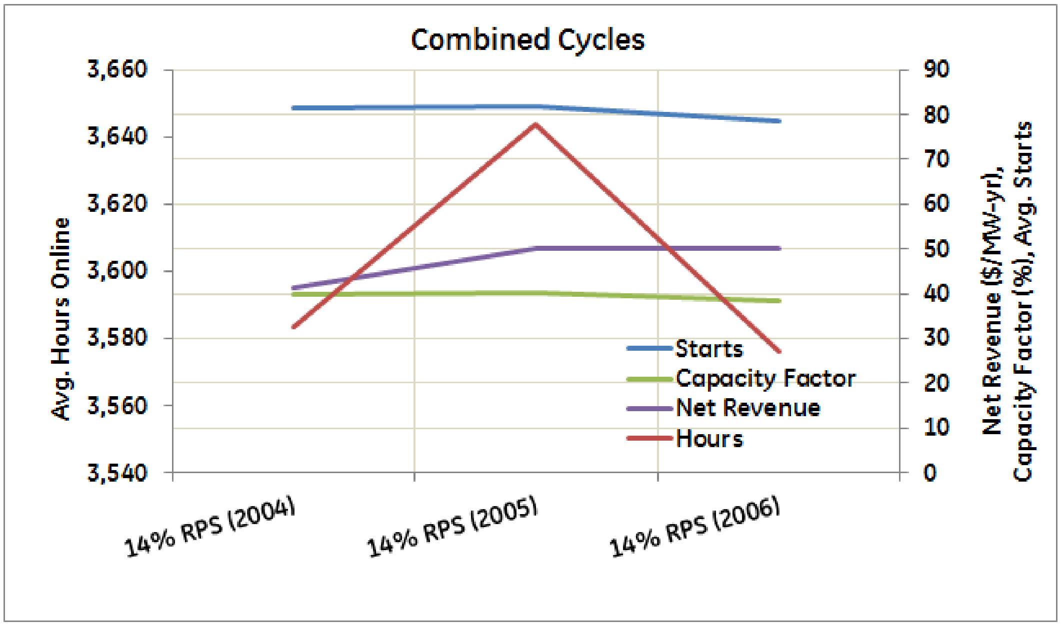

Figure 2-20: Variation in Performance of CCGT units under Different Profile Years (14% RPS Scenario)

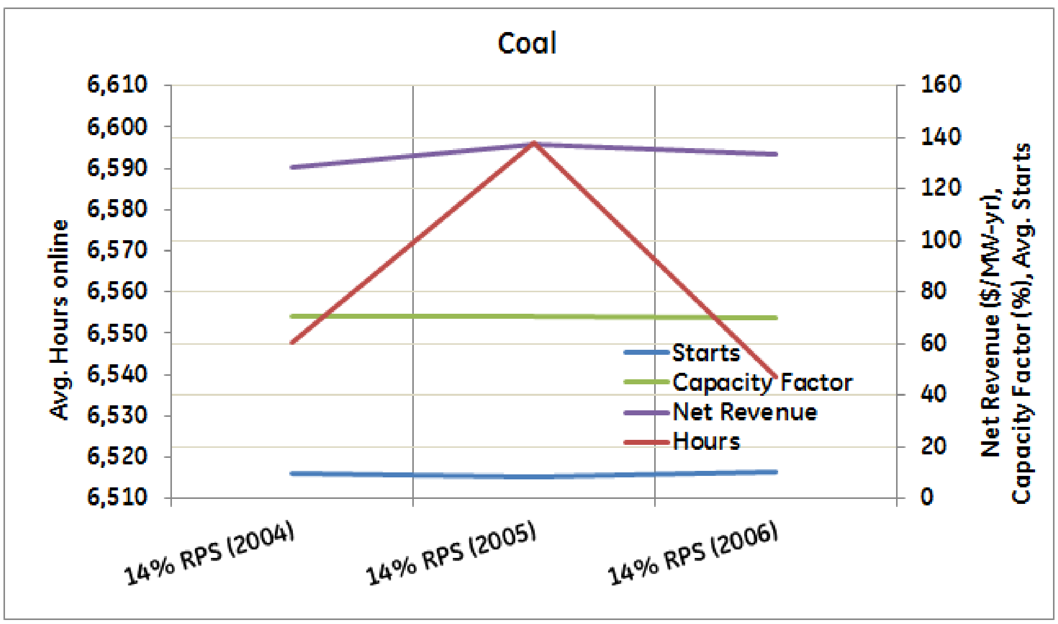

Figure 2-21: Variation in Performance of Coal units under Different Profile Years (14% RPS Scenario)

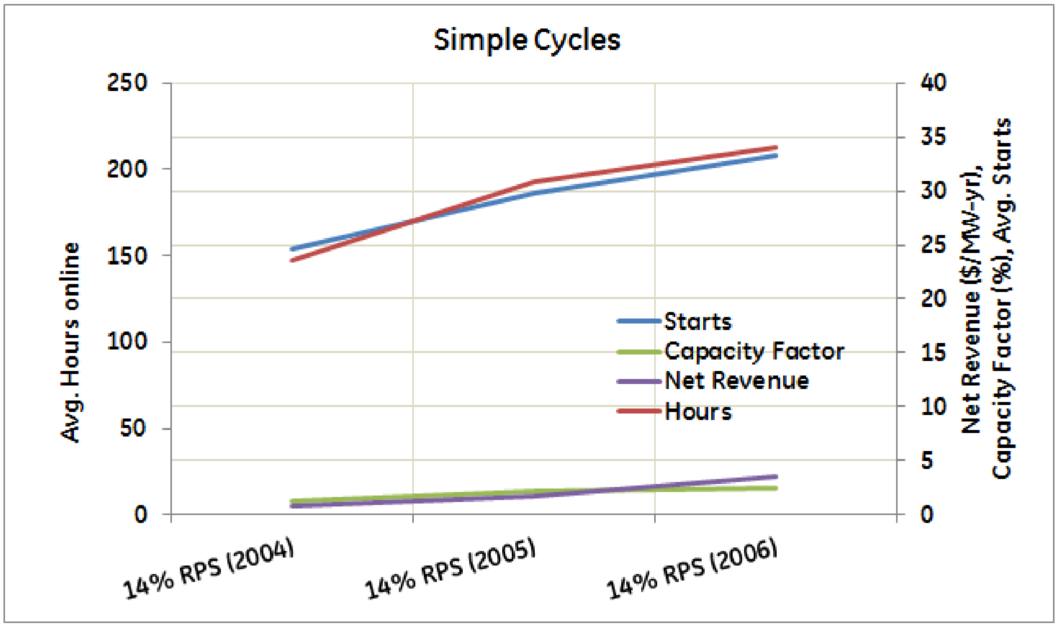

Figure 2-22: Variation in Performance of SCGT units under Different Profile Years (14% RPS Scenario)

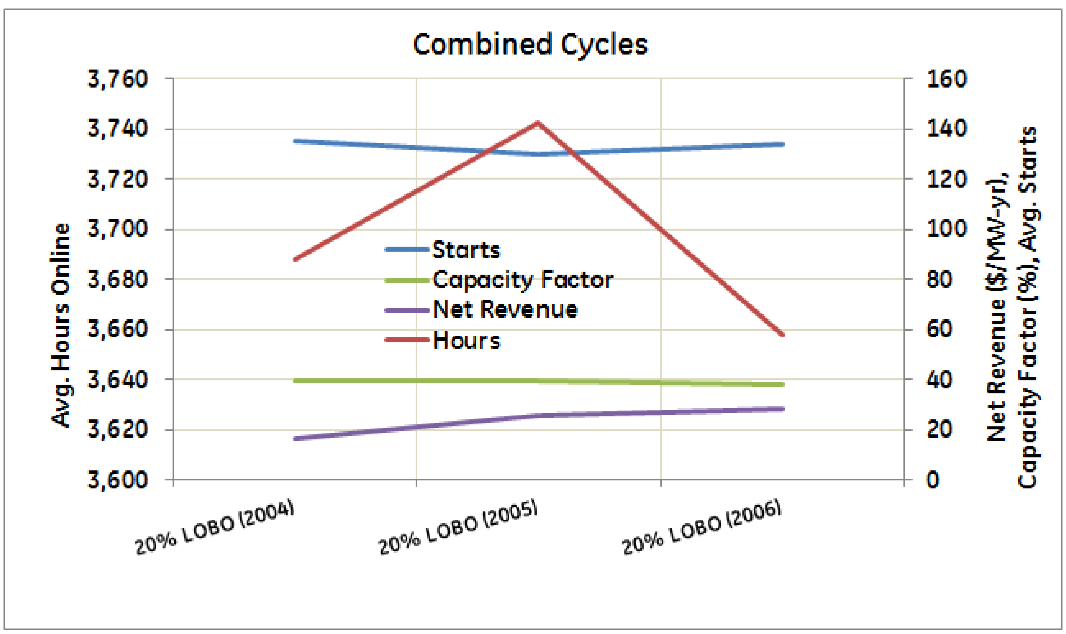

Figure 2-23: Variation in Performance of CCGT units under Different Profile Years (20% LOBO Scenario)

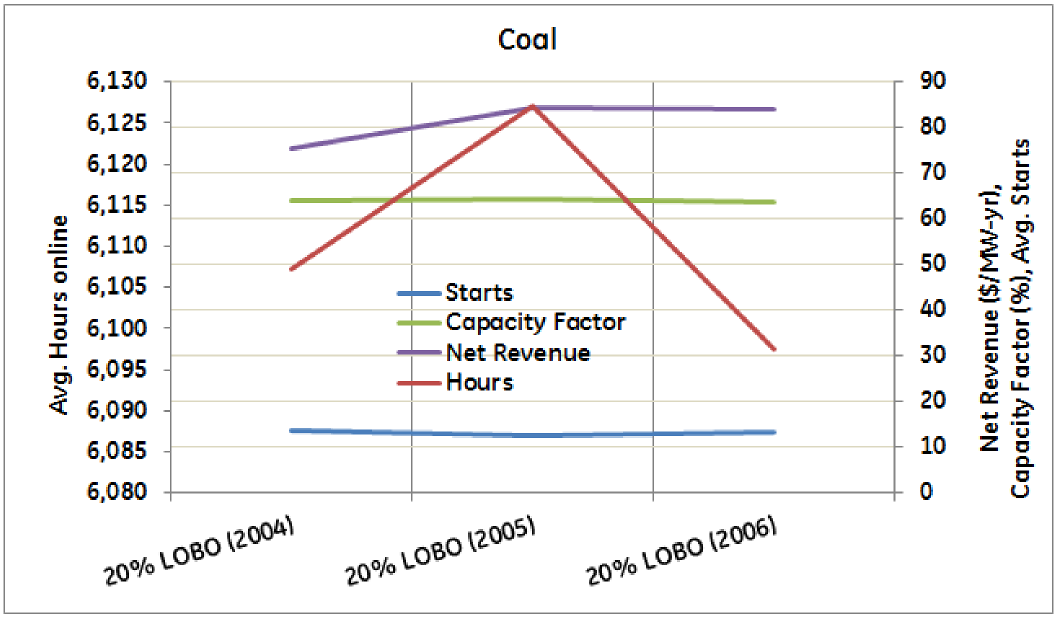

Figure 2-24: Variation in Performance of Coal units under Different Profile Years (20% LOBO Scenario)

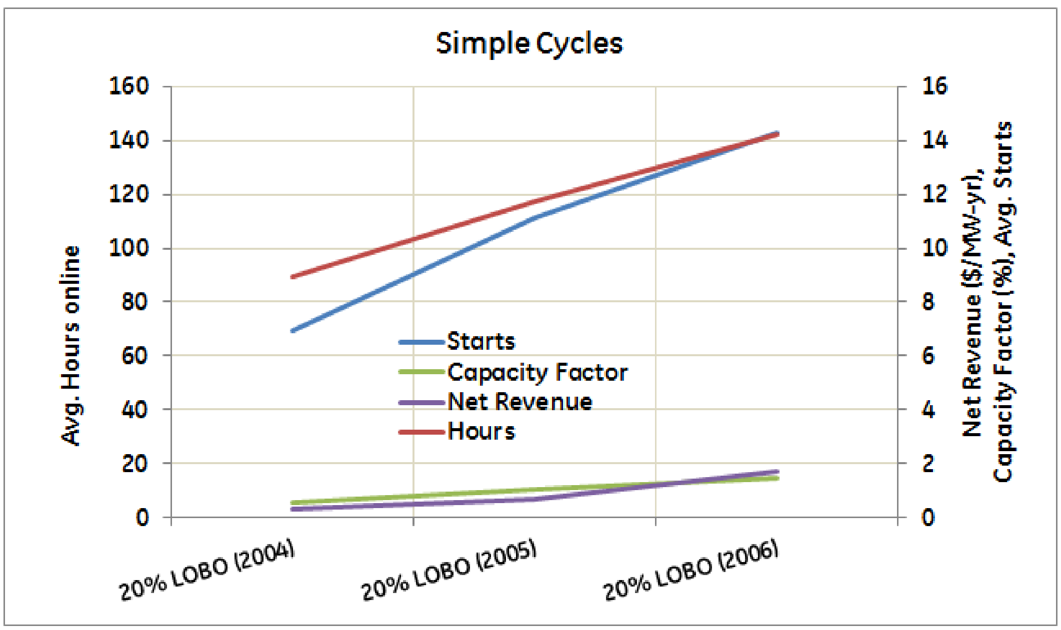

Figure 2-25: Variation in Performance of SCGT units under Different Profile Years (20% LOBO Scenario)

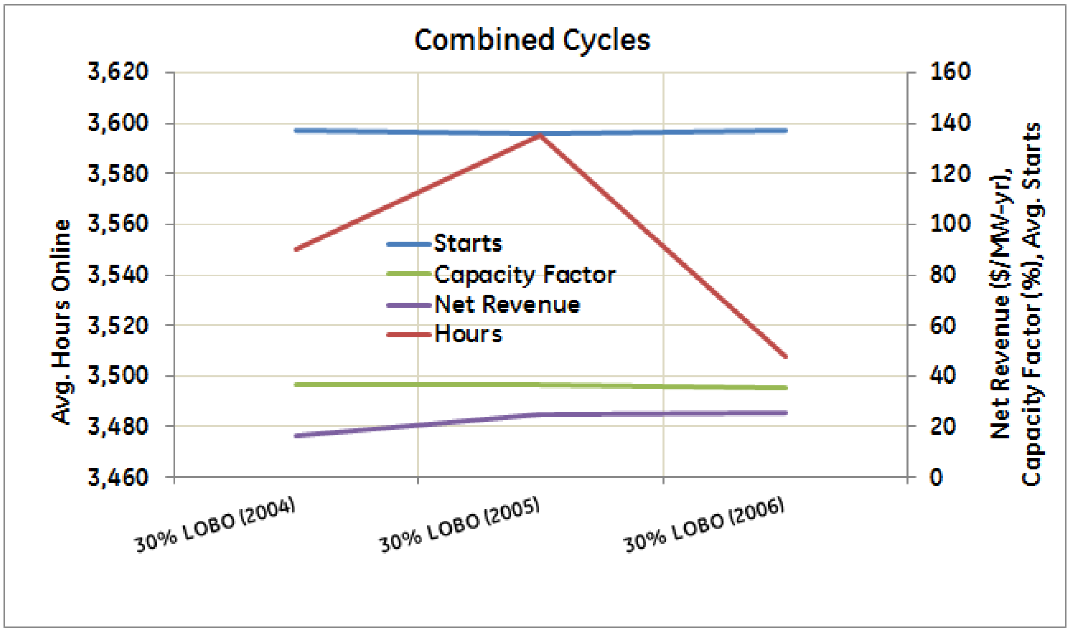

Figure 2-26: Variation in Performance of CCGT units under Different Profile Years (30% LOBO Scenario)

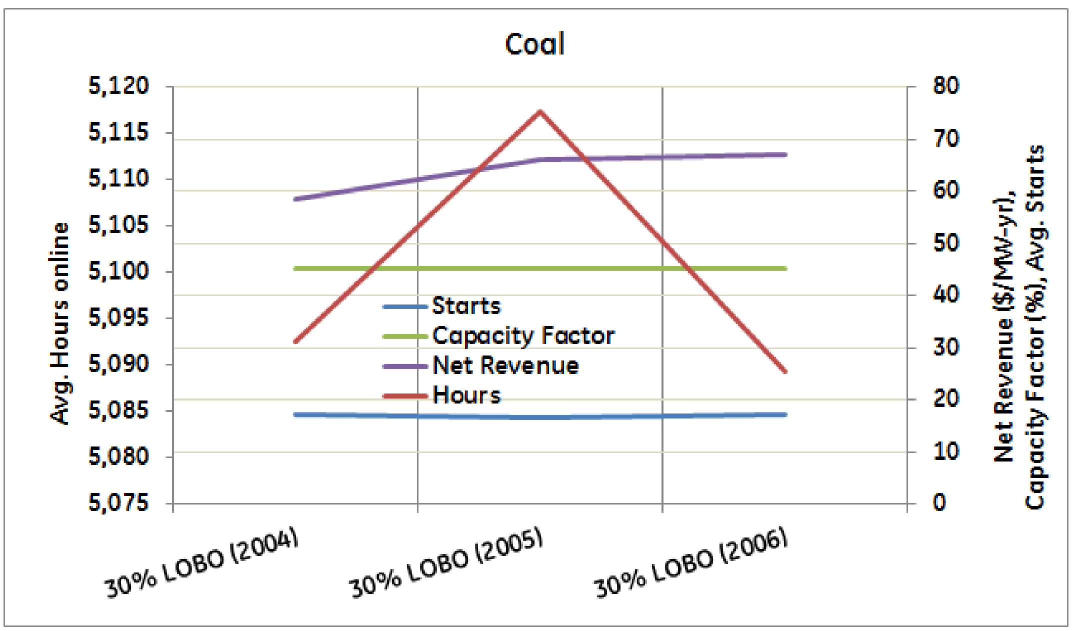

Figure 2-27: Variation in Performance of Coal units under Different Profile Years (30% LOBO Scenario)

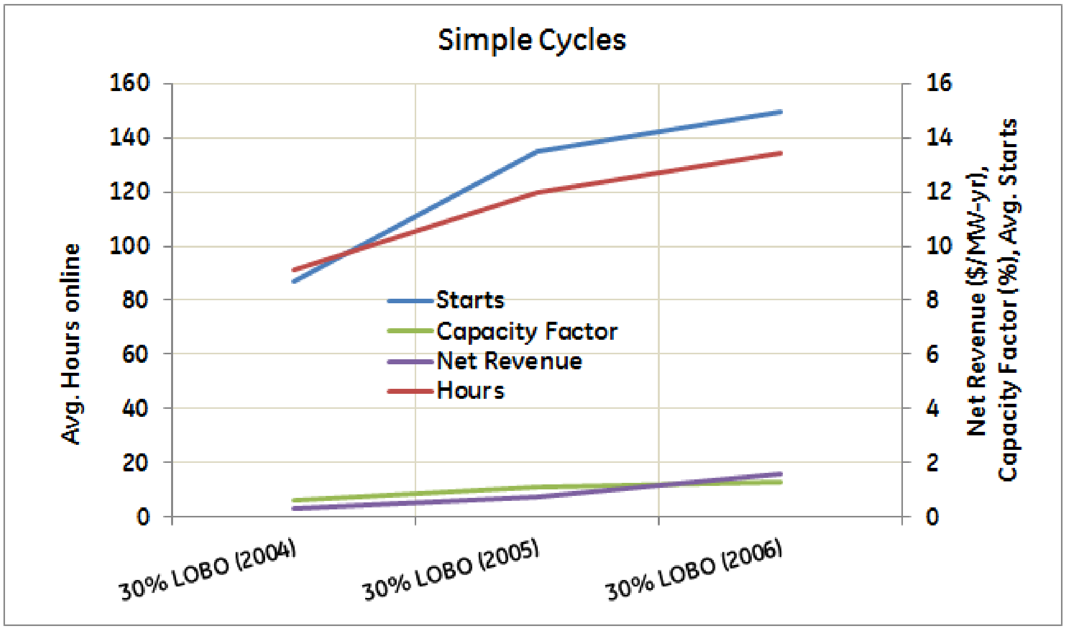

Figure 2-28: Variation in Performance of SCGT units under Different Profile Years (30% LOBO Scenario)

Except for the generally low penetration 2% BAU scenario, the main difference in unit type performances between different profile years is the change in Average Hours Online of unit types, which for CCGT and coal units is highest under 2005 profile years and lowest in 2006 profile year. This behavior is consistent with the relative level of wind generation under the examined profile years, with most wind generation under 2006 profile year and least wind generation under 2005 profile year. However, in relative terms, the CCGT and coal unit Average Hours Online variations are not significant.

2.3 Economic Performance

The following figures and tables in this section depict the variation in economic performance under different profile years.

Economic indicators examined include:

PJM Production Cost, which includes all variable costs of operations (fuel costs, VOM costs, start-up costs);

- PJM Generator Gross Revenues, which is the energy market based revenue of PJM generators (i.e., LMP times Generation), which also accounts for the exports;
- PJM Wholesale Customer Energy Cost, which is the sum of Zonal Prices times Load; and
- Load Weighted LMP, which is PJM average LMP

Graphical and tabular Results are shown for each of the selected scenarios (2% BAU, 14% RPS, 20% LOBO, and 30% LOBO).

Following charts and table summarize the results for the 2% BAU scenarios.

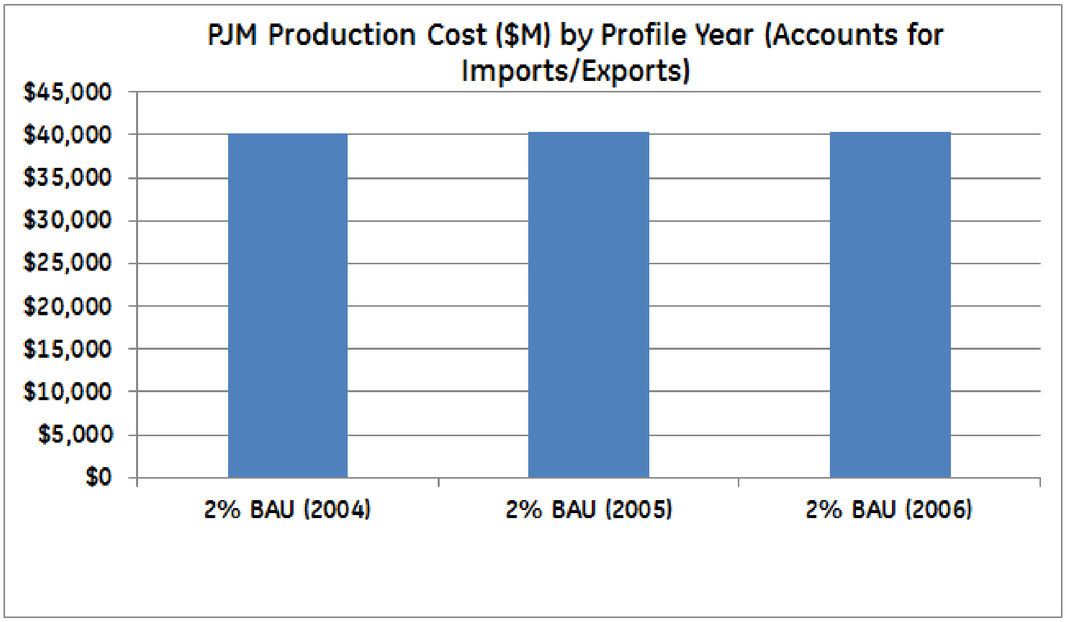

Figure 2-29: PJM Production Cost under Different Profile Years (2% BAU Scenario)

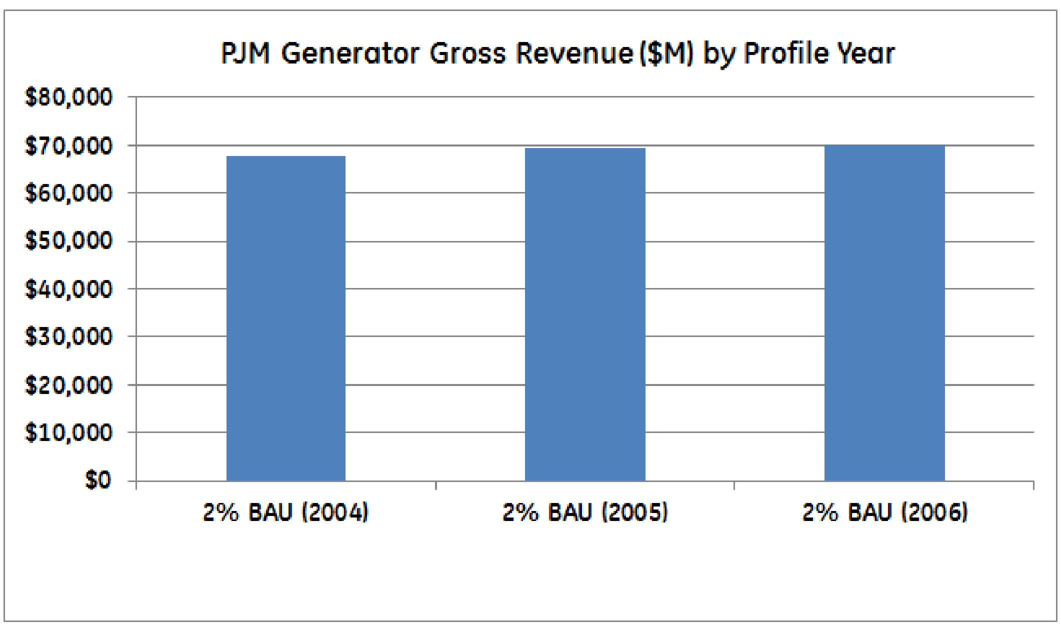

Figure 2-30: PJM Generator Gross Revenue under Different Profile Years (2% BAU Scenario)

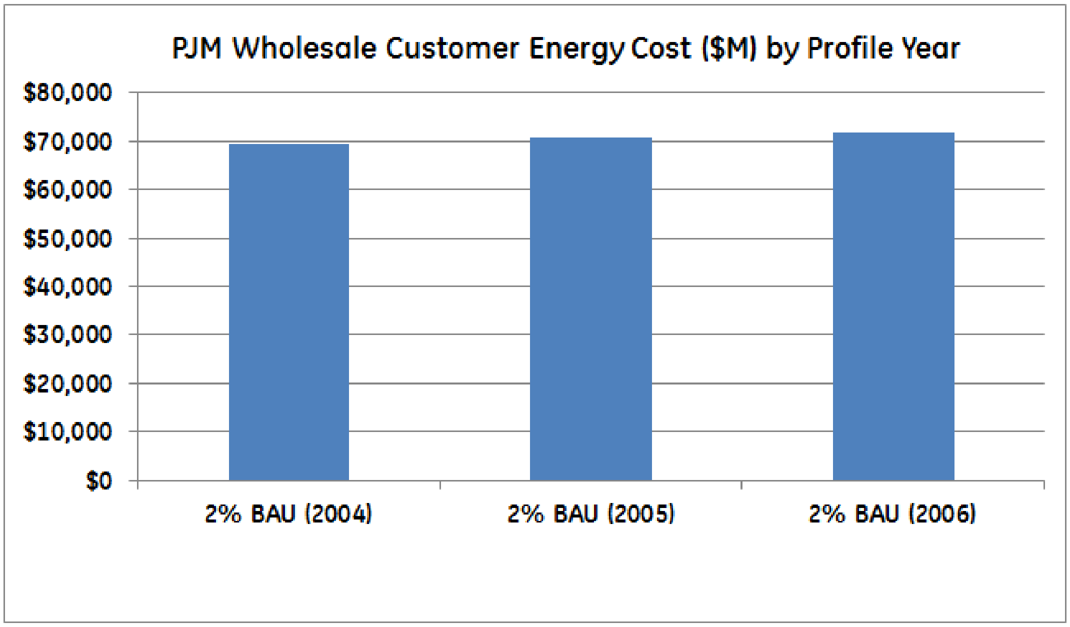

Figure 2-31: PJM Wholesale Customer Energy Cost under Different Profile Years (2% BAU Scenario)

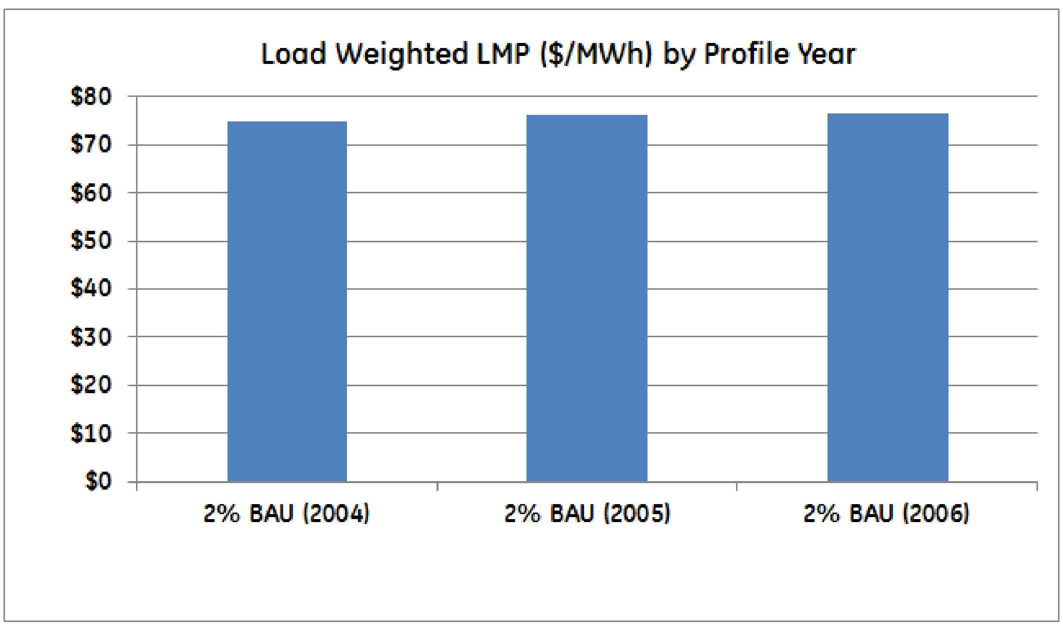

Figure 2-32: Average PJM LMP under Different Profile Years (2% BAU Scenario)

Table 2-1: Economic Performance under Different Profile Years (2% BAU Scenario)

2% BAU	2004 Shape	2005 Shape	2006 Shape
Production Costs ($M)	40,241	40,318	40,470
Absolute Change from 2006 Shape	-229	-153	0
Change Relative to 2006 Shape	-0.57%	-0.38%	0.00%
Generator Gross Revenue ($M)	67,763	69,402	70,023
Absolute Change from 2006 Shape	-2,260	-621	0
Change Relative to 2006 Shape	-3.23%	-0.89%	0.00%
Cost to Load ($M)	69,487	70,605	71,773
Absolute Change from 2006 Shape	-2,286	-1,168	0
Change Relative to 2006 Shape	-3.19%	-1.63%	0.00%
Load Weighted LMP ($/MWh)	74.9	76.2	76.5
Absolute Change from 2006 Shape	-1.6	-0.3	0.0
Change Relative to 2006 Shape	-2.05%	-0.43%	0.00%

Graphical results show noticeable variations in economic attributes in the 2% BAU scenario under different profile years. The tabulated results show a few percentage points change under 2004 and 2005 profile years compared to 2006 profile year. There is a drop in PJM Generator Gross Revenues, PJM costs to serve load, and Load Weighted LMP. The PJM Costs to Serve Load with 2004 and 2005 profile years are lower by about $2.2B and $1.2B relative to the 2006 profile year – corresponding decreases in Load Weighted LMP are $1.57/MWh and $0.33/MWh, respectively.

Following charts and table summarize the results for the 14% RPS scenarios.

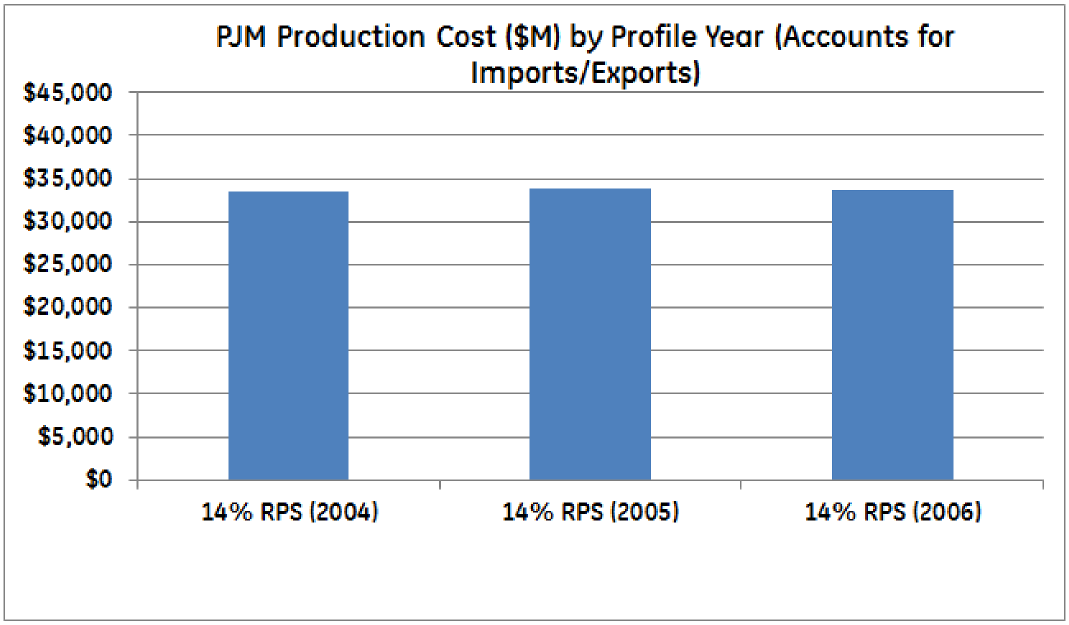

Figure 2-33: PJM Production Cost under Different Profile Years (14% RPS Scenario)

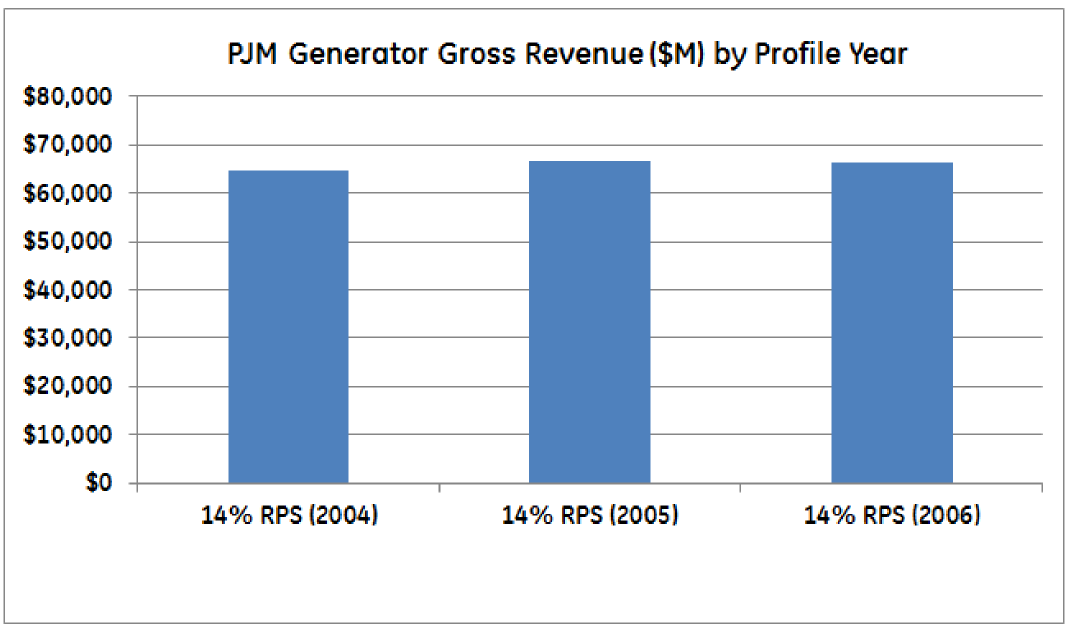

Figure 2-34: PJM Generator Gross Revenue under Different Profile Years (14% RPS Scenario)

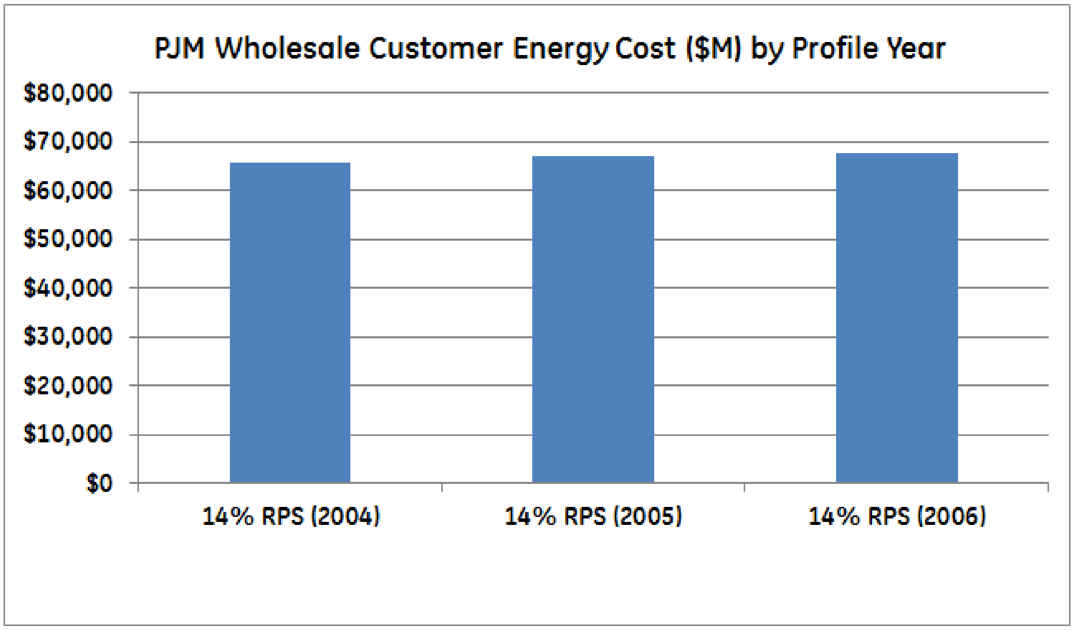

Figure 2-35: PJM Wholesale Customer Energy Cost under Different Profile Years (14% RPS Scenario)

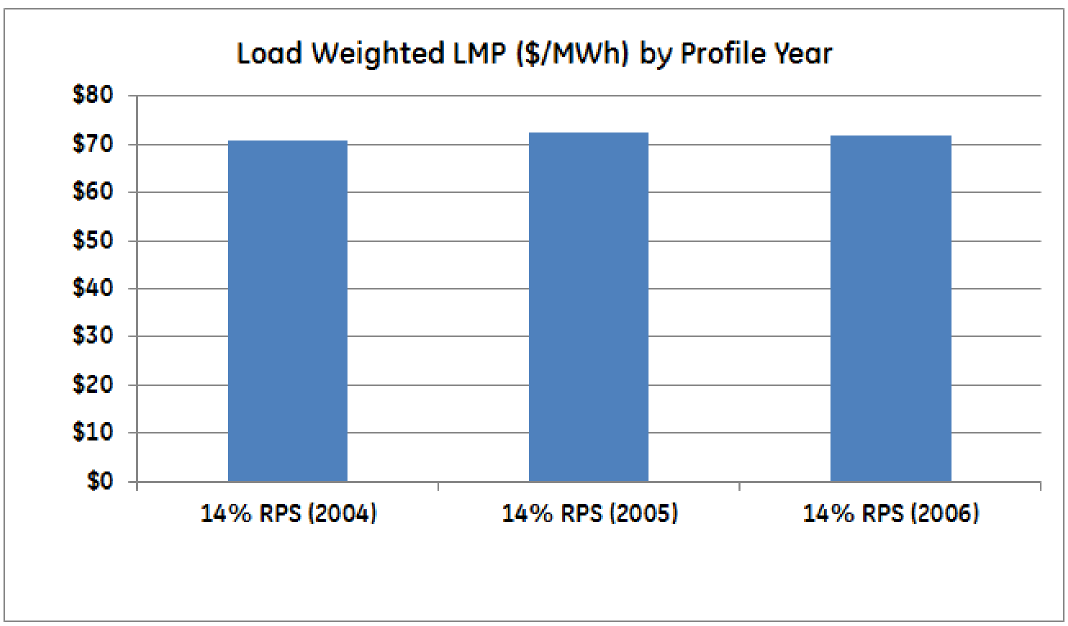

Figure 2-36: Average PJM LMP under Different Profile Years (14% RPS Scenario)

Table 2-2: Economic Performance under Different Profile Years (14% RPS Scenario)

14% RPS	2004 Shape	2005 Shape	2006 Shape
Production Costs ($M)	33,522	33,906	33,719
Absolute Change from 2006 Shape	-197	187	0
Change Relative to 2006 Shape	-0.59%	0.55%	0.00%
Generator Gross Revenue ($M)	64,794	66,620	66,390
Absolute Change from 2006 Shape	-1,596	230	0
Change Relative to 2006 Shape	-2.40%	0.35%	0.00%
Cost to Load ($M)	65,755	67,227	67,608
Absolute Change from 2006 Shape	-1,853	-381	0
Change Relative to 2006 Shape	-2.74%	-0.56%	0.00%
Load Weighted LMP ($/MWh)	70.9	72.5	71.8
Absolute Change from 2006 Shape	-0.9	0.7	0.0
Change Relative to 2006 Shape	-1.29%	0.96%	0.00%

In the preceding charts, the 14% RPS scenario exhibits noticeable but not significant variation across the different profile years. The corresponding table shows a few percentage point variation under 2004 and 2005 profile years compared to the 2006 profile year, some positive and some negative. The PJM Costs to Serve Load is with 2004 and 2005 profile years are lower by about $1.9B and $0.4B relative to the 2006 profile year – corresponding decreases in Load Weighted LMP are $1.57/MWh and $0.33/MWh, respectively.

Following charts and table summarize the results for the 20% LOBO scenario.

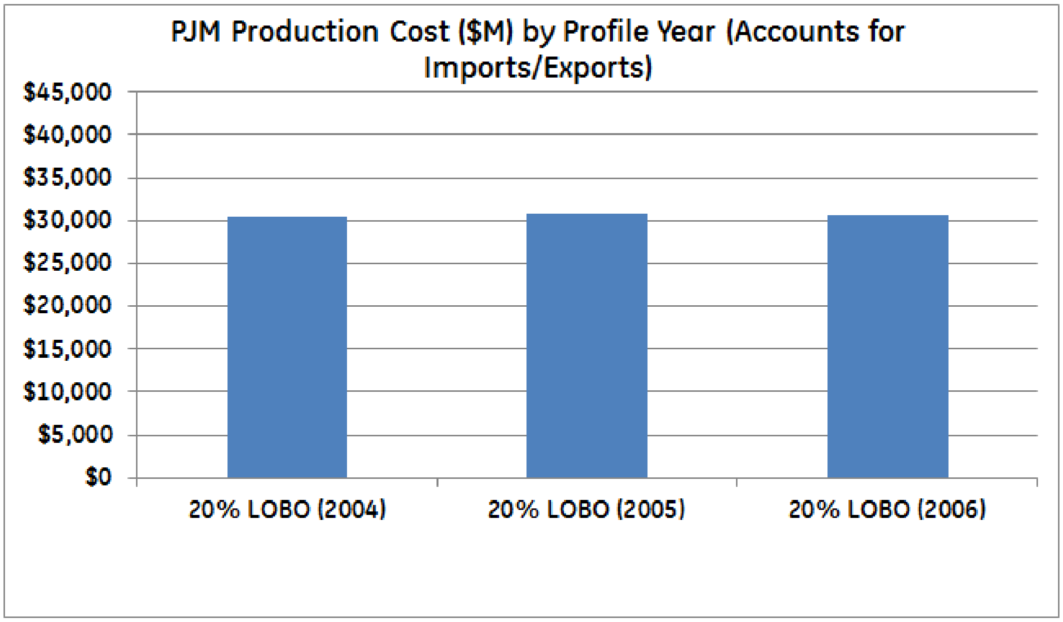

Figure 2-37: PJM Production Cost under Different Profile Years (20% LOBO Scenario)

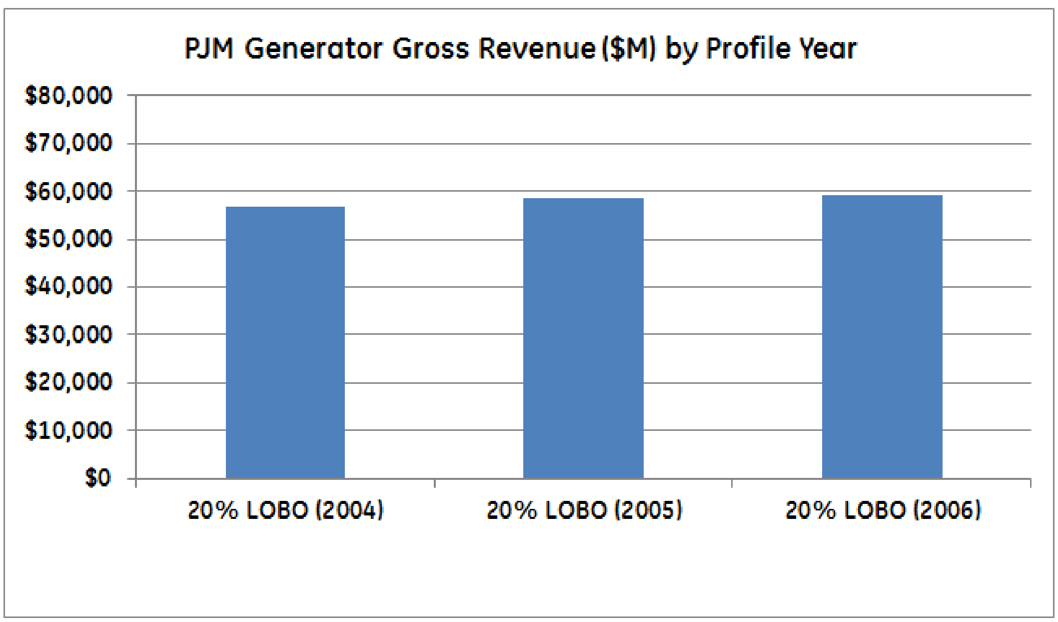

Figure 2-38: PJM Generator Gross Revenue under Different Profile Years (20% LOBO Scenario)

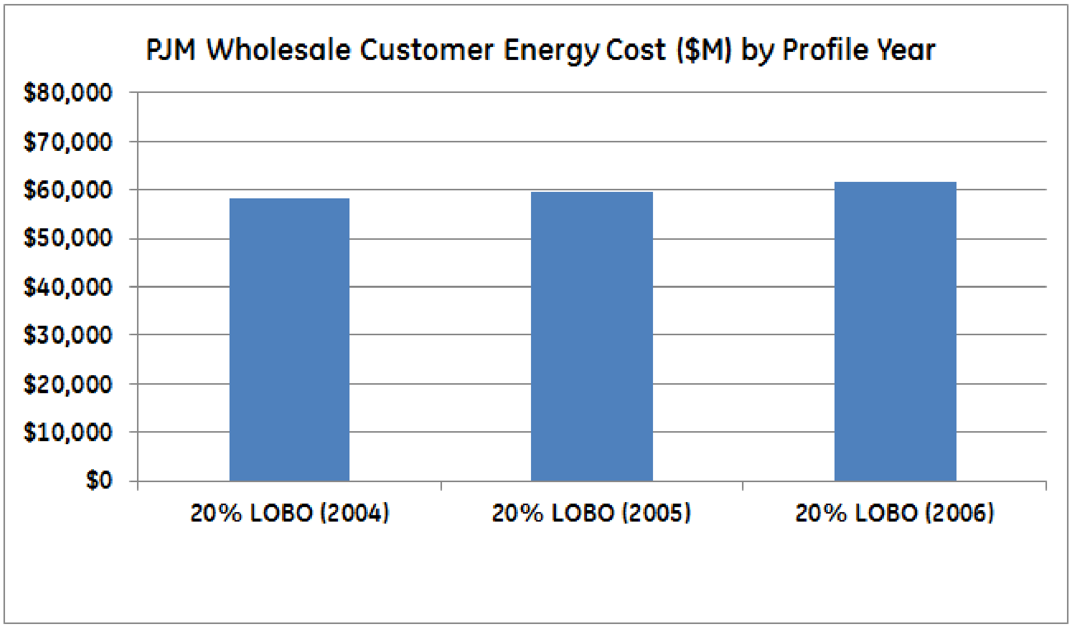

Figure 2-39: PJM Wholesale Customer Energy Cost under Different Profile Years (20% LOBO Scenario)

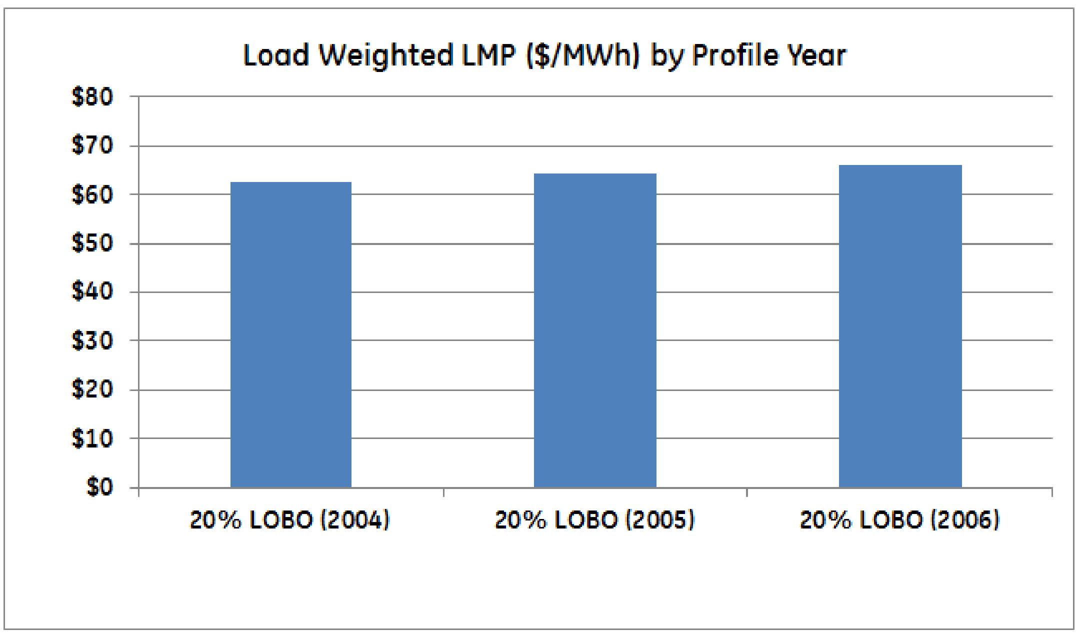

Figure 2-40: Average PJM LMP under Different Profile Years (20% Lobo Scenario)

Table 2-3: Economic Performance under Different Profile Years (20% LOBO Scenario)

20% LOBO	2004 Shape	2005 Shape	2006 Shape
Production Costs ($M)	30,496	30,731	30,610
Absolute Change from 2006 Shape	-114	121	0
Change Relative to 2006 Shape	-0.37%	0.39%	0.00%
Generator Gross Revenue ($M)	56,861	58,536	59,178
Absolute Change from 2006 Shape	-2,317	-642	0
Change Relative to 2006 Shape	-3.91%	-1.09%	0.00%
Costs to Load ($M)	58,155	59,613	61,635
Absolute Change from 2006 Shape	-3,480	-2,022	0
Change Relative to 2006 Shape	-5.65%	-3.28%	0.00%
Load Weighted LMP ($/MWh)	62.7	64.3	66.1
Absolute Change from 2006 Shape	-3.4	-1.8	0.0
Change Relative to 2006 Shape	-5.19%	-2.77%	0.00%

Again, the preceding graphical presentations show noticeable but not significant variations in the economic indicators of the 20% LOBO scenario across the different profile years. The corresponding table shows a few percentage point variation under 2004 and 2005 profile years compared to the 2006 profile year, mostly negative. The PJM Costs to Serve Load is with 2004 and 2005 profile years are lower by about $3.5B and $2.0B relative to the 2006 profile year – corresponding decreases in Load Weighted LMP are $3.44/MWh and $1.83/MWh, respectively.

Following charts and table summarize the results for the 30% LOBO scenario.

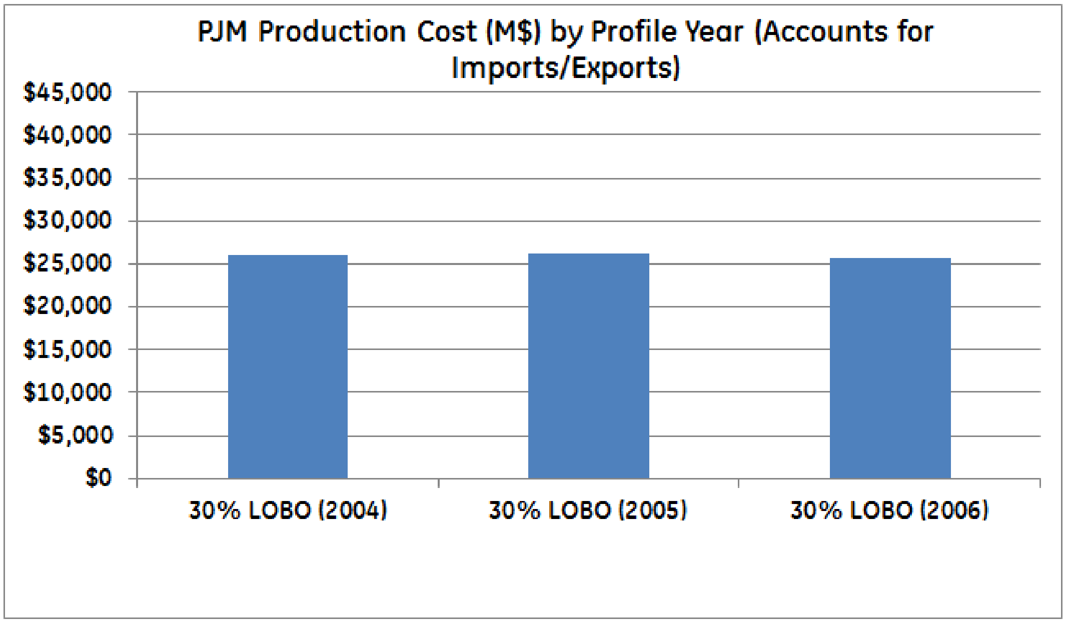

Figure 2-41: PJM Production Cost under Different Profile Years (20% LOBO Scenario)

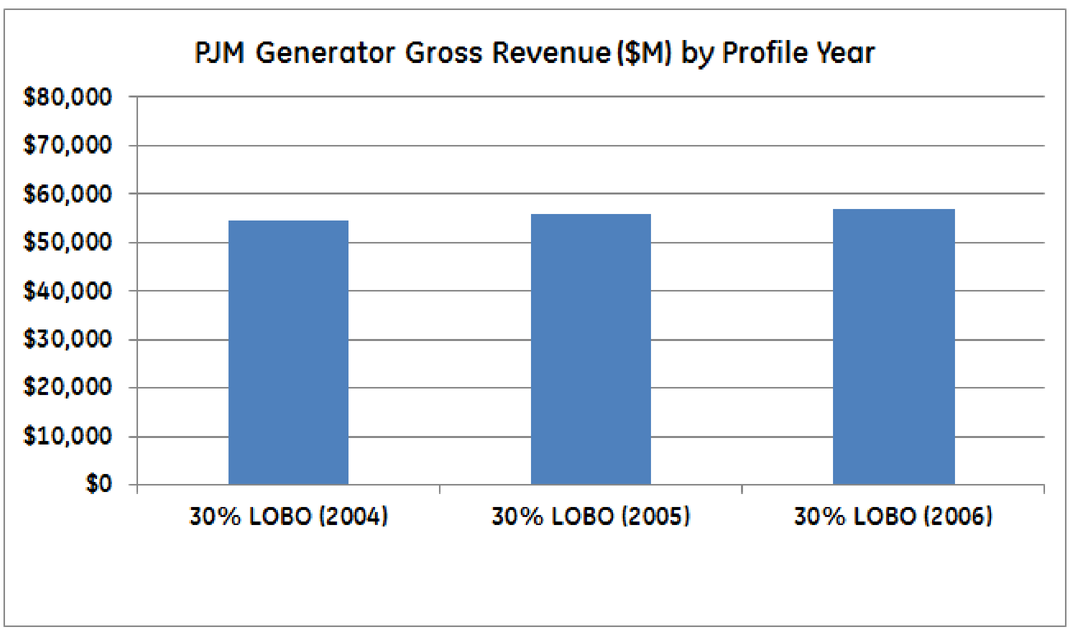

Figure 2-42: PJM Generator Gross Revenue under Different Profile Years (30% LOBO Scenario)

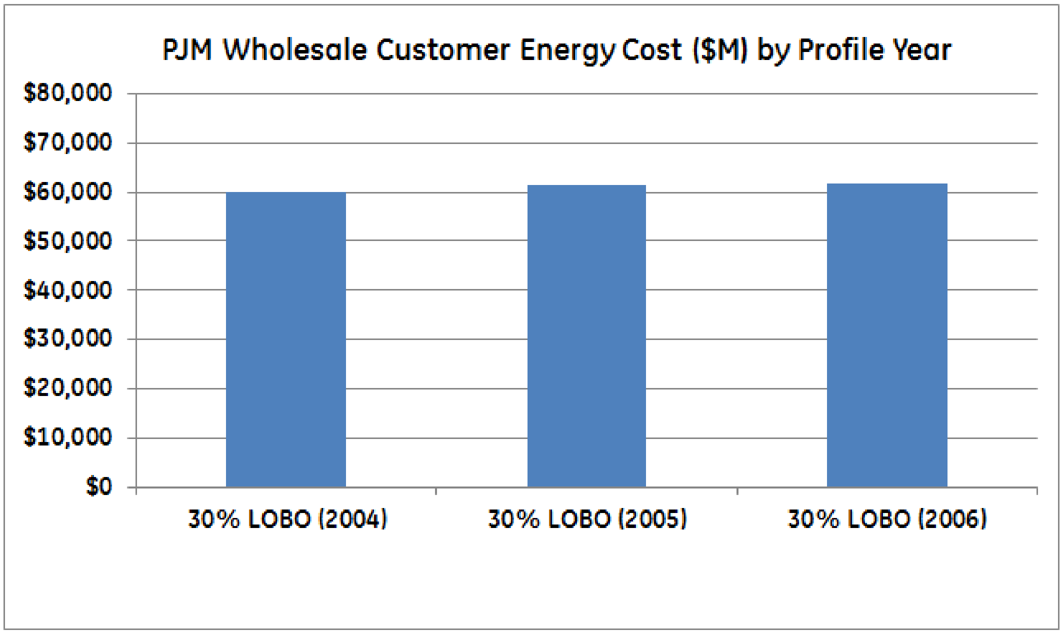

Figure 2-43: PJM Wholesale Customer Energy Cost under Different Profile Years (30% LOBO Scenario)

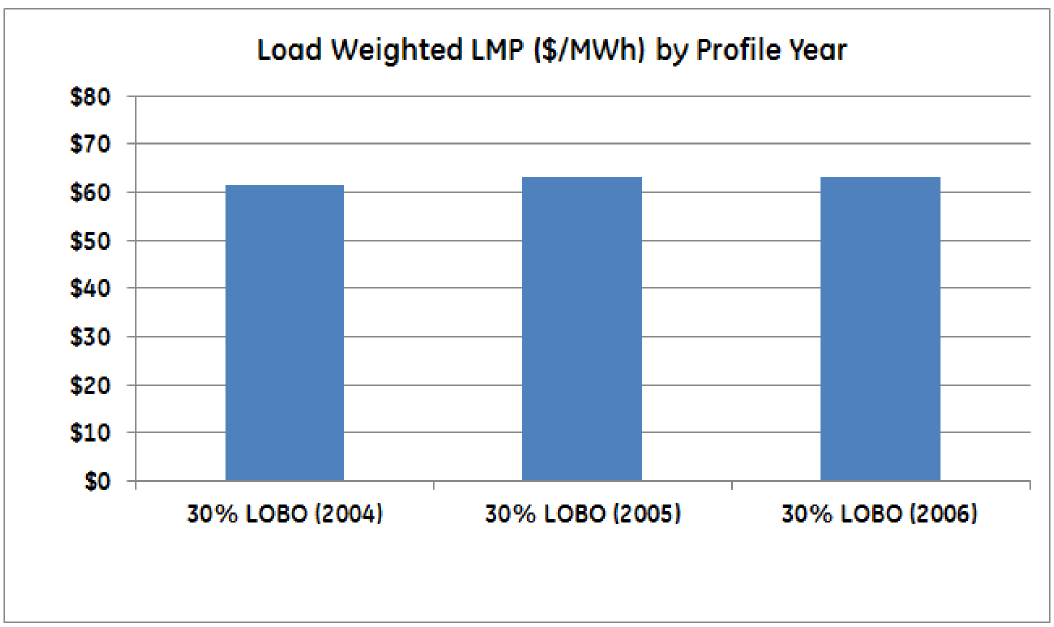

Figure 2-44: Average PJM LMP under Different Profile Years (30% Lobo Scenario)

Table 2-4: Economic Performance under Different Profile Years (30% LOBO Scenario)

30% LOBO	2004 Shape	2005 Shape	2006 Shape
Production Costs ($M)	26,003	26,248	25,707
Absolute Change from 2006 Shape	295	541	0
Change Relative to 2006 Shape	1.15%	2.10%	0.00%
Generator Gross Revenue ($M)	54,516	55,946	56,860
Absolute Change from 2006 Shape	-2,344	-914	0
Change Relative to 2006 Shape	-4.12%	-1.61%	0.00%
Costs to Load ($M)	60,048	61,470	61,635
Absolute Change from 2006 Shape	-1,587	-165	0
Change Relative to 2006 Shape	-2.58%	-0.27%	0.00%
Load Weighted LMP ($/MWh)	61.6	63.1	63.2
Absolute Change from 2006 Shape	-1.6	-0.1	0.0
Change Relative to 2006 Shape	-2.58%	-0.22%	0.00%

Similar to other scenarios, the figures above depict noticeable but not significant variations in the economic indicators of the 30% LOBO scenario across the different profile years. The corresponding table shows a few percentage point variation under 2004 and 2005 profile years compared to the 2006 profile year, all negative. The PJM Costs to Serve Load is with 2004 and 2005 profile years are lower by about $1.6B and $0.2B relative to the 2006 profile year – corresponding decreases in Load Weighted LMP are $1.63/MWh and $0.14/MWh, respectively.

2.4 Base Profile Year Analysis Observations and Conclusions

In summary, using the different profile years does not appear to have a large impact on results. Variations in economic indicators, such as PJM Wholesale Customer Energy Cost, are in low single digit billions of dollars.

Similar conclusions have been reached in other renewable integration studies.

3 Sensitivity Analysis

3.1 Sensitivity List

This section introduces the sensitivity analyses. Each sensitivity analysis starts with a Base Case which reflects the main assumptions of the study that define the PJM power system and constitute the model inputs. The sensitivity analysis is performed by changing one or two variable at a time, and comparing results to the base case scenario. The intent is to isolate, in so far as possible, specific factors that will influence operations or costs. The differential approach tends to filter out much of the impact of assumptions that are unimportant to the specific investigation, while providing insights for PJM. Many of the sensitivities presented are aimed at providing guidance on the efficacy of various strategies or options aimed at improving performance. The choices of variables cover a wide range of drivers of interest that impact the robustness of the system to respond to renewable resource volatility.

In consultation with PJM, it was decided that the sensitivity analysis should be performed on the major drivers of generation and costs in PJM, namely, load, gas prices, carbon costs, and renewable forecast. For simplicity and inclusion, the following five sensitivities were selected by PJM:

LL	Low Load Growth: 6.1% reduction in demand energy compared to the base case
LG	Low Natural Gas Price: AEO forecast of $6.50/MMBtu[1] compared to $8.02/MMBtu in the base case
LL, LG	Low Load Growth & Low Natural Gas Price
LG, C	Low Natural Gas Price & High Carbon Cost: Carbon Cost $40/Ton compared to $0/Ton in the base case
PF	Perfect Wind & Solar forecast: Perfect knowledge of the wind and solar for commitment and dispatch, which provides a benchmark of the maximum possible benefit from forecast improvements.

[1] http://www.eia.gov/forecasts/aeo/

Additional sensitivities were performed under Tasks 3b and 4.

The rational for the 6.1% reduction in demand energy for the Low Load Growth GE scenario is as follows: GE internal load forecast is very closely aligned with PJM's 2013 Load Forecast using the central estimate of the Federal Reserve's GDP growth. Given that GE load forecast (which is based on a regression of electricity intensity, GDP, and annual load) is closely aligned with PJM, it was decided that for the sensitivity analysis, the GE assumed load forecast be reduced to the Federal Reserve's lower GDP growth forecast. This decreases the assumed GDP growth from ~2.6% per year to ~2.2%. As a result, decreasing the energy growth rates from about 1% per year to ~0.6% per year, would lead to lead to a 6.1% decrease in annual energy for PJM by 2026; hence, a reasonable representation of a "low load growth" scenario.

The $40/Ton was considered to be a reasonable Carbon Cost sensitivity in discussions of GE and PJM teams.

Please note that the transmission system overlays were unchanged for any of the sensitivities.

3.2 2% BAU Sensitivities

3.2.1 2% BAU Operational Performance Sensitivities

Figure 3-1 to Figure 3-4 present the operational performance of 2% BAU scenario under different sensitivities. The delivered renewable generation remains relatively unchanged under all the sensitivity cases since renewable generation is not subject to dispatch except that it may be curtailed when necessary. As expected, under the Low Load Growth sensitivity, the thermal generation is lower than the base case. Under the Low Load Growth with Low Gas and pure Low Gas sensitivities, coal generation is displaced by CCGT generation.

The most remarkable impact is under the Low Gas with Carbon Price sensitivity. As shown in the figures, there is a significant shift from coal generation to CCGT and SCGT generation. As expected, lower coal generation also results in a significant drop in emissions volume.

The Perfect Forecast sensitivity appears to have no significant impact on 2% BAU scenario operational performance. One interpretation is that the renewable forecast used in day-ahead unit commitment is very close to the actual renewable generation used in hour by hour economic dispatch. A more likely interpretation is that at 2% penetration, forecast error does not really make much impact.

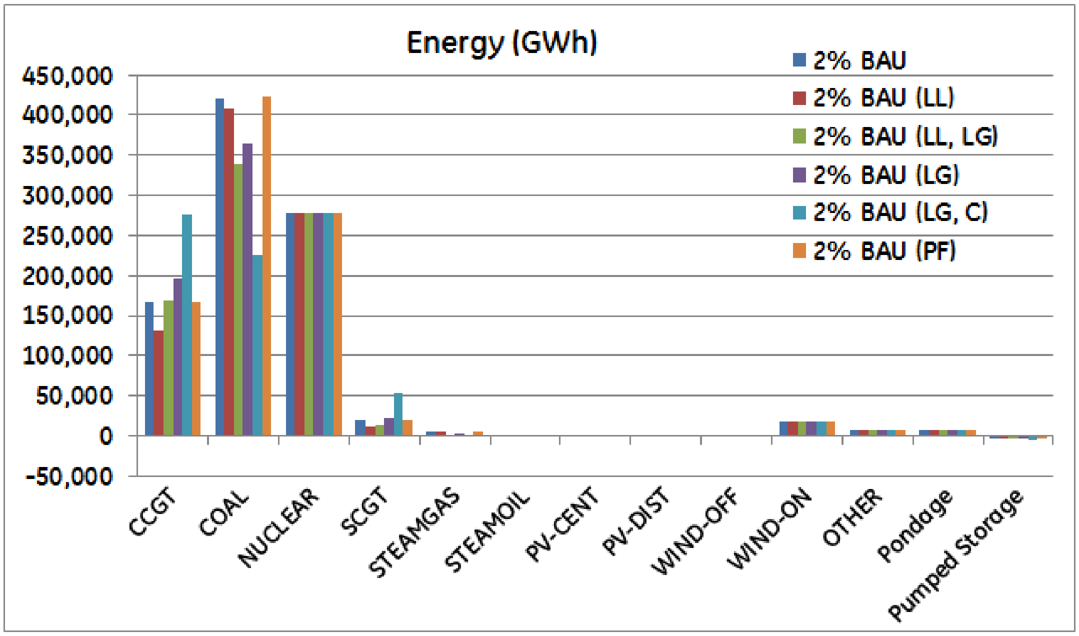

Figure 3-1: 2% BAU Sensitivities - Energy by Type

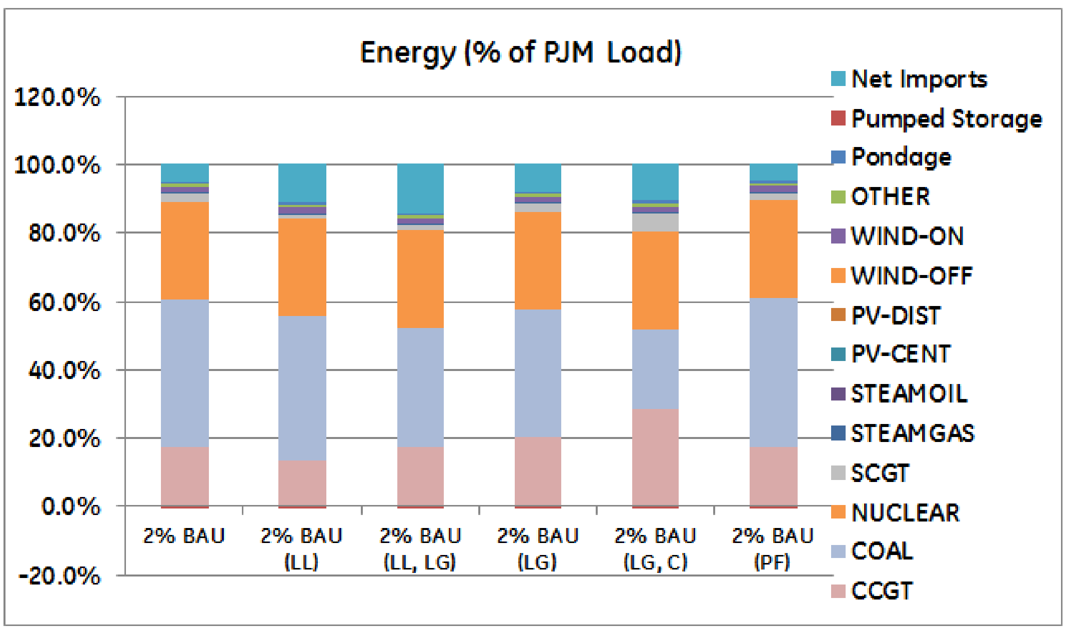

Figure 3-2: 2% BAU Sensitivities - Energy as % of Load

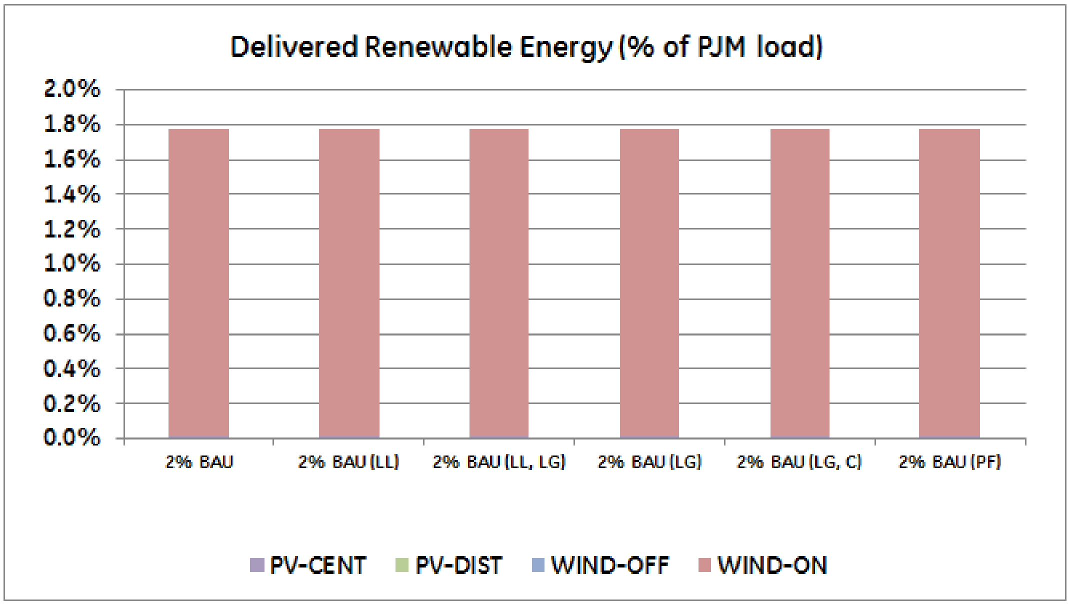

Figure 3-3: 2% BAU Sensitivities - Delivered Renewable Energy

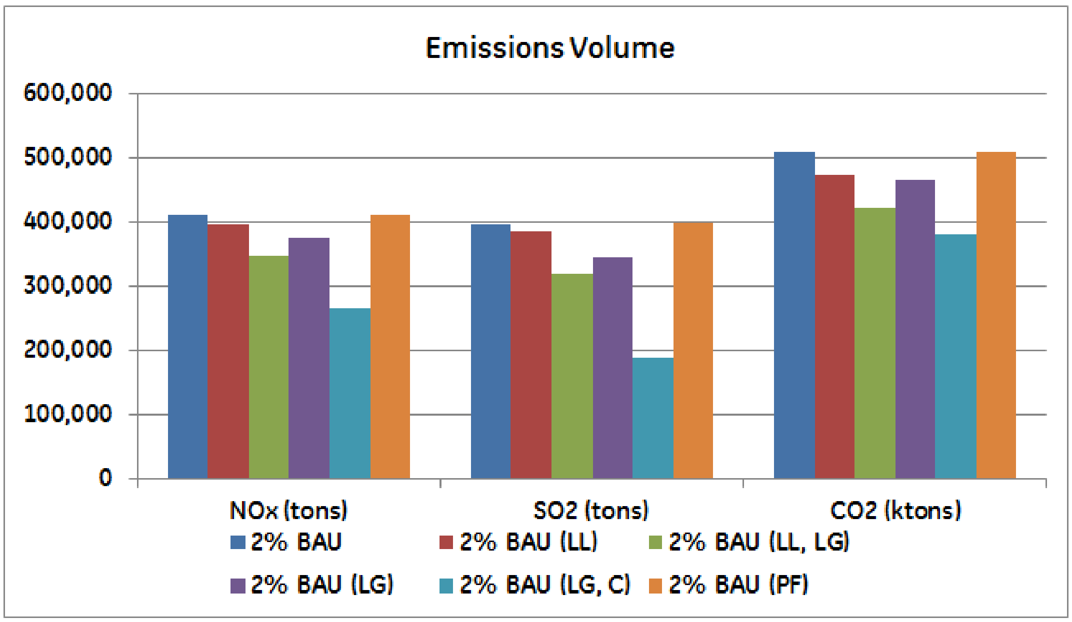

Figure 3-4: 2% BAU Sensitivities - Emissions Volume

3.2.2 2% BAU Unit Performance Sensitivities

Figure 3-5 to Figure 3-7 present the unit performance by type. Consistent with previous results, the Coal unit performance indicators exhibit a significant drop in the Low Gas with Carbon Price sensitivity, the opposite of which is true for CCGT and SCGT units. The changes are less dramatic but still significant in other sensitivities. The Perfect Forecast sensitivity does not appear to result in any significant change in performance of any of the units types considered.

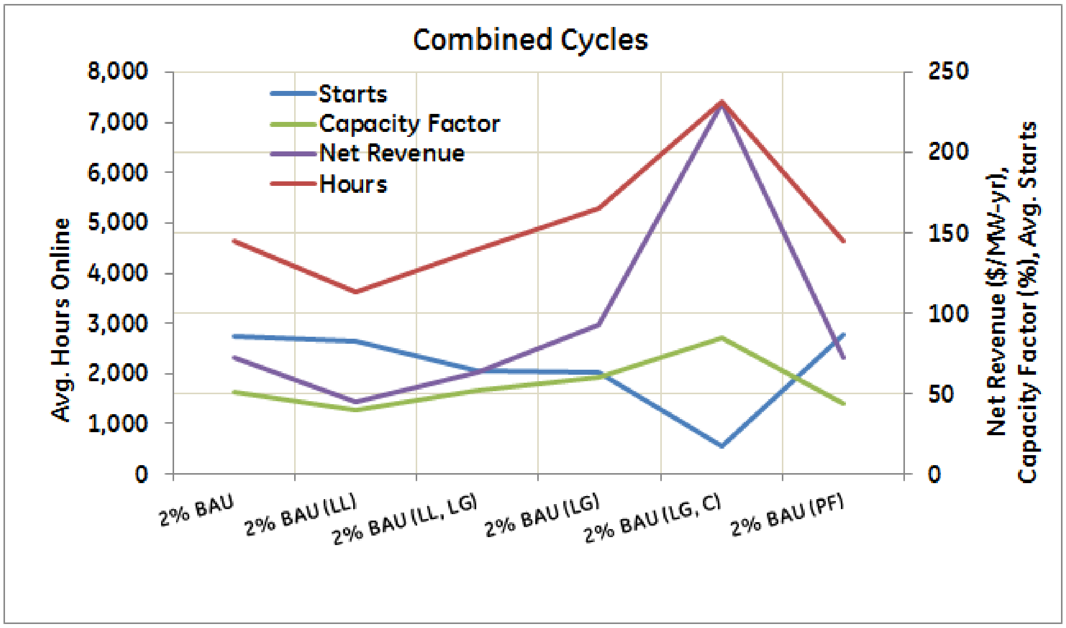

Figure 3-5: 2% BAU Sensitivities - CCGT Performance

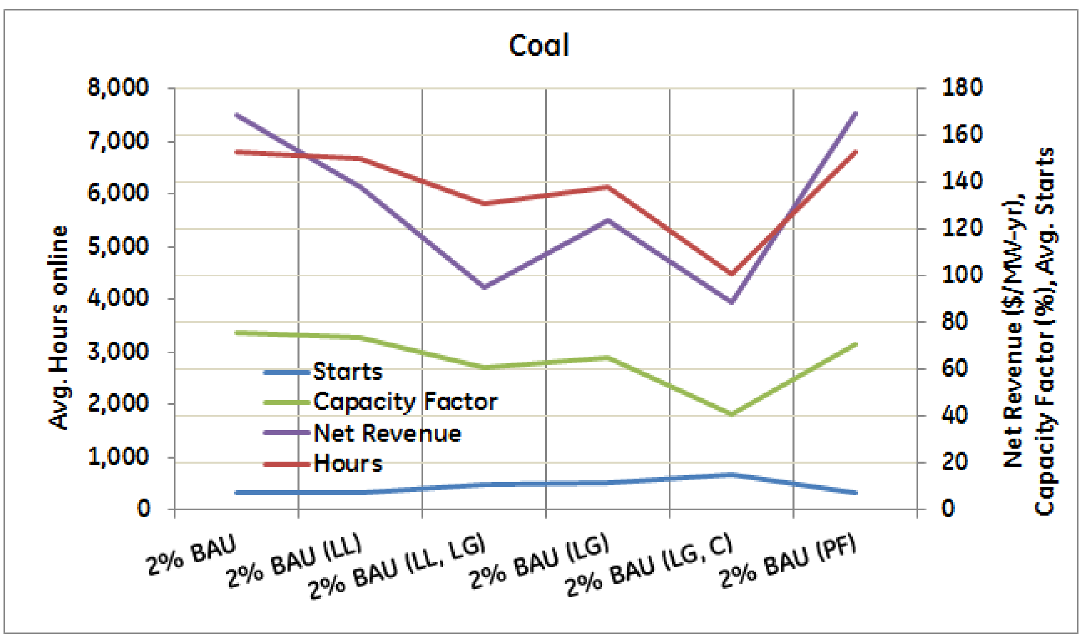

Figure 3-6: 2% BAU Sensitivities - Coal Performance

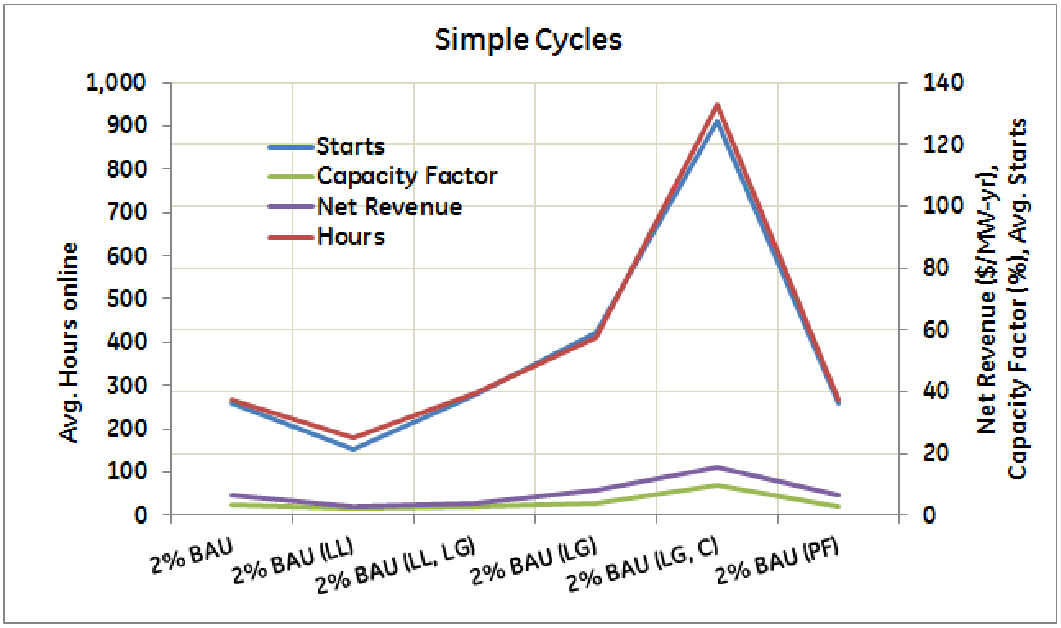

Figure 3-7: 2% BAU Sensitivities - SCGT Performance

3.2.3 2% BAU Economic Performance Sensitivities

Figure 3-8 to Figure 3-11 and Table 3-1 present the economic performance of 2% BAU scenario under different sensitivities. As could be expected, economic indicators are lowest the Low Load Growth with Low Gas sensitivity results in the lowest value of PJM wide economic indicators, and conversely, the Low Gas with Carbon Price sensitivity results in the highest values of PJ M wind economic indicators.

As shown in Table 3-1, the Perfect Forecast sensitivity results in minimal change in economic indicators compared to the base case. However, there are wide variations in same economic indicators across the other sensitivities. All the other sensitivities, except Low Gas with Carbon Price sensitivity result in lower PJM wide costs, revenues, and prices.

The widest variations in the PJM Wholesale Customer Energy Costs compared to the Base Case are under the Low Load Growth with Low Gas sensitivity (a decrease of $13.9B), and under the Low Gas with Carbon Price sensitivity (an increase of $29.6B). Relative to the Base Case, the average PJM LMP prices decrease by $10.81/MWh under the Low Load Growth with Low Gas sensitivity, and increase by $31.91/MWh under the Low Gas with High Carbon Price sensitivity.

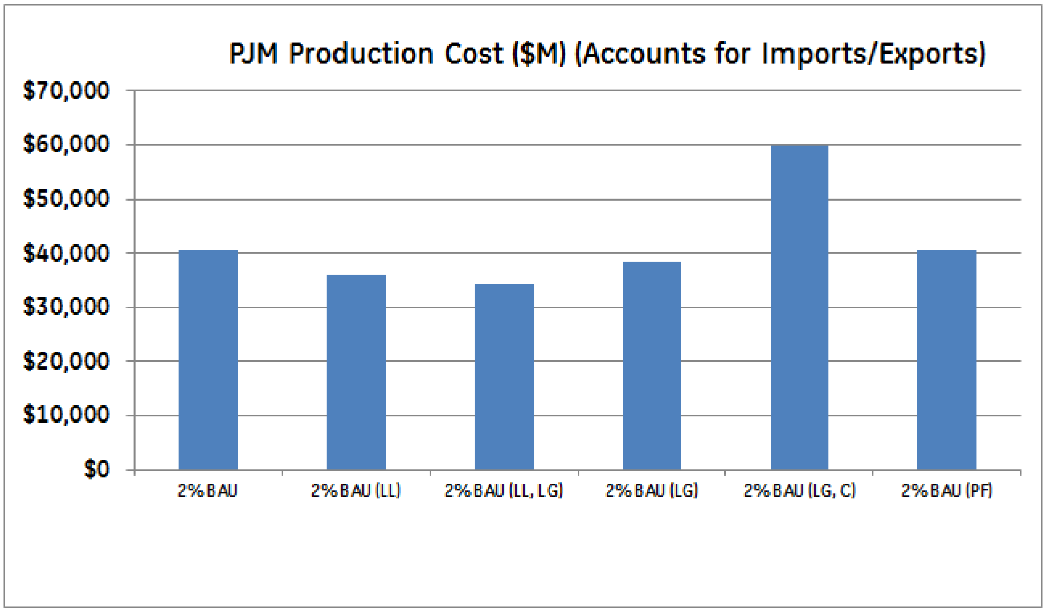

Figure 3-8: 2% BAU Sensitivities - PJM Production Cost

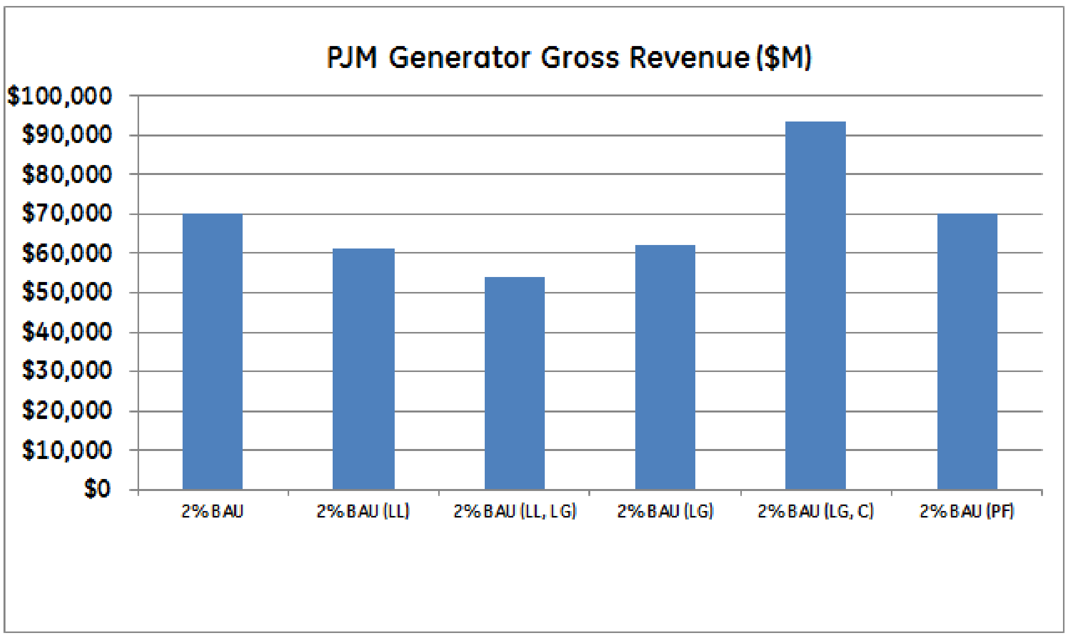

Figure 3-9: 2% BAU Sensitivities – PJM Generator Gross Revenue

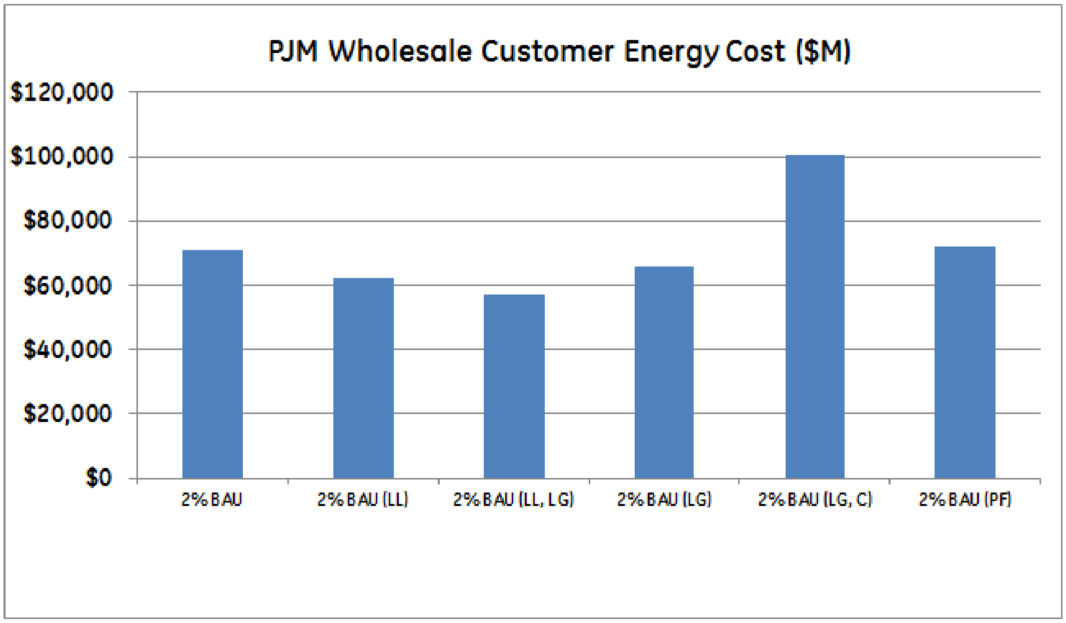

Figure 3-10: 2% BAU Sensitivities - PJM Wholesale Customer Energy Cost

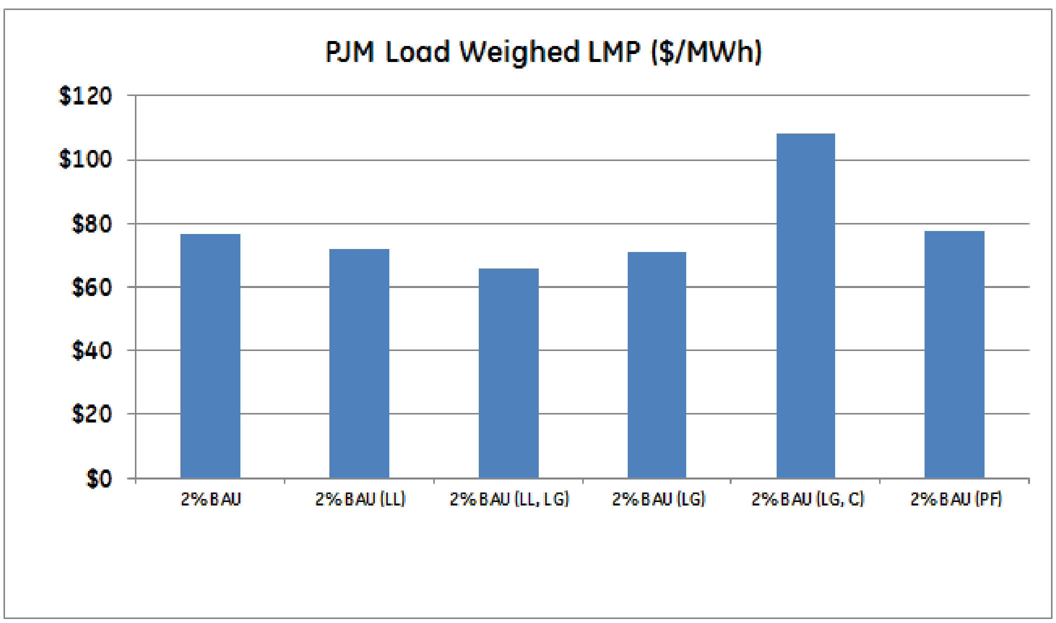

Figure 3-11: 2% BAU Sensitivities - PJM Load Weighted LMP

Table 3-1: Summary of 2% BAU Sensitivities

PJM Sensitivities	2% BAU	2% BAU (LL)	2% BAU (LL, LG)	2% BAU (LG)	2% BAU (LG, C)	2% BAU (PF)
Production Costs ($M)	40,470	36,099	34,370	38,341	59,763	40,462
Change from Base	0	-4,372	-6,100	-2,129	19,292	-8
Relative Change	0.00%	-12.11%	-17.75%	-5.55%	32.28%	-0.02%
Generator Revenue ($M)	70,023	61,057	53,826	62,263	93,352	70,182
Change from Base	0	-8,966	-16,197	-7,760	23,328	158
Relative Change	0.00%	-14.68%	-30.09%	-12.46%	24.99%	0.23%
Costs to Load ($M)	70,947	62,358	57,036	65,814	100,545	71,795
Change from Base	0	-8,589	-13,911	-5,133	29,597	848
Relative Change	0.00%	-13.77%	-24.39%	-7.80%	29.44%	1.18%
Load Wtd LMP ($/MWh)	76.5	71.8	65.7	70.9	108.4	77.4
Change from Base	0.0	-4.7	-10.8	-5.5	31.9	0.9
Relative Change	0.00%	-6.51%	-16.45%	-7.79%	29.44%	1.18%

3.3 14% RPS Sensitivities

3.3.1 14% RPS Operational Sensitivities

Figure 3-12 to Figure 3-15 present the operational performance of 14% RPS scenario under different sensitivities. The delivered renewable generation remains relatively unchanged under all the sensitivity cases since renewable generation is not subject to dispatch except that it may be curtailed when necessary. As expected, under the Low Load Growth sensitivity, the thermal generation is lower than the base case. Under the Low Load Growth with Low Gas and pure Low Gas sensitivities, coal generation is displaced by CCGT generation.

As with the 2% BAU scenario, the most remarkable impact is under the Low Gas with Carbon Price sensitivity. As shown in the figures, there is a significant shift from coal generation to CCGT and SCGT generation, which is reflected in the capacity factor values as well. As expected, lower coal generation also results in a significant drop in emissions volume.

The Perfect Forecast sensitivity appears to have no significant impact on 14% RPS scenario operational performance. One interpretation is that the renewable forecast used in day-ahead unit commitment is very close to the actual renewable generation used in hour by hour economic dispatch.

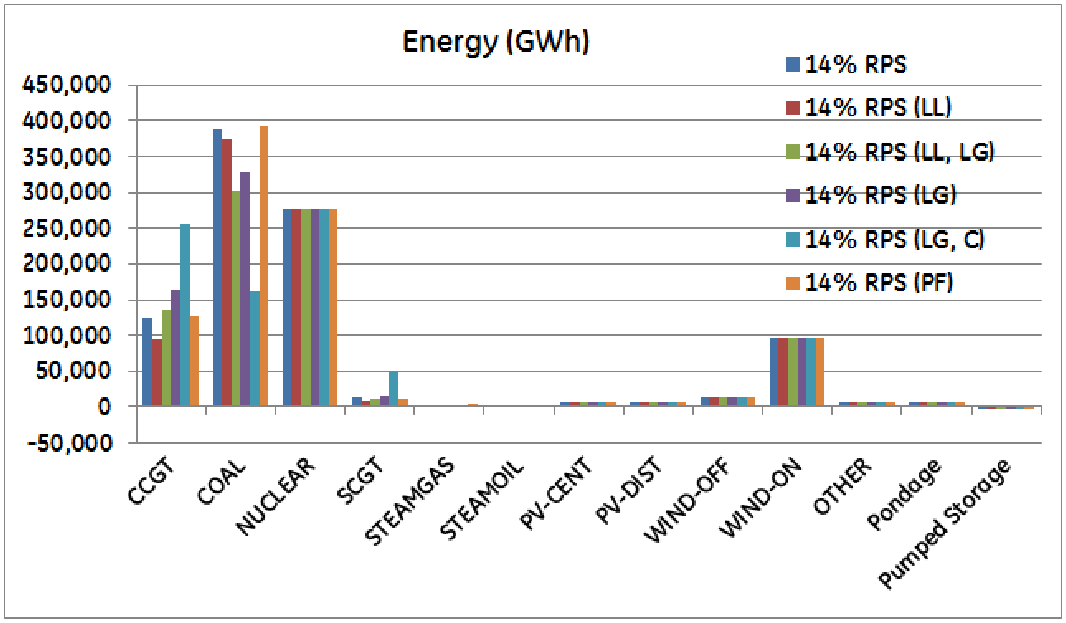

Figure 3-12: 14% RPS Sensitivities – Energy by Type

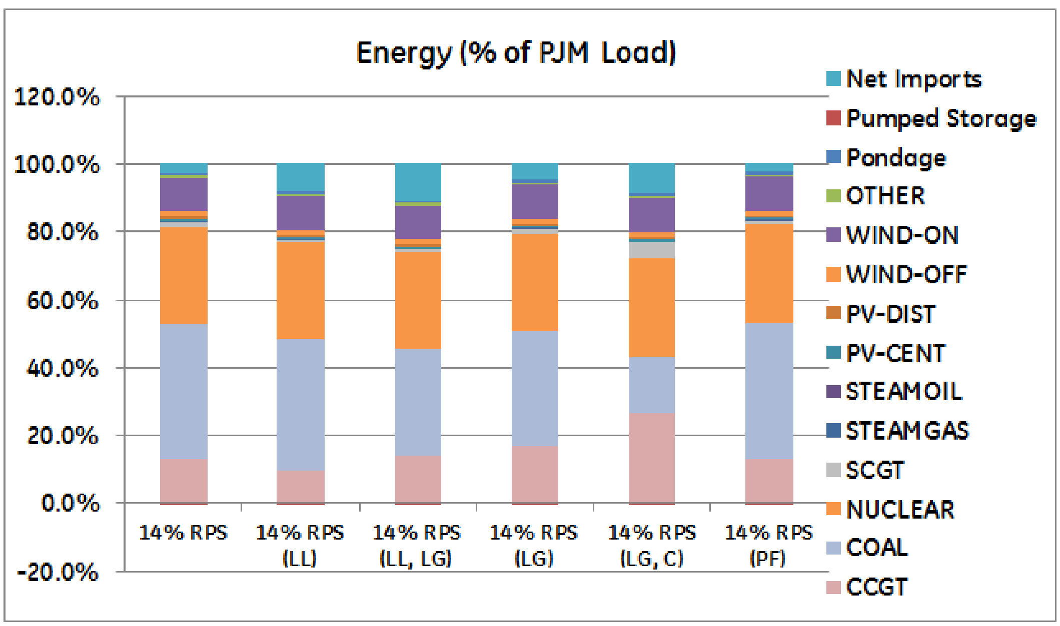

Figure 3-13: 14% RPS Sensitivities - Energy as % of Load

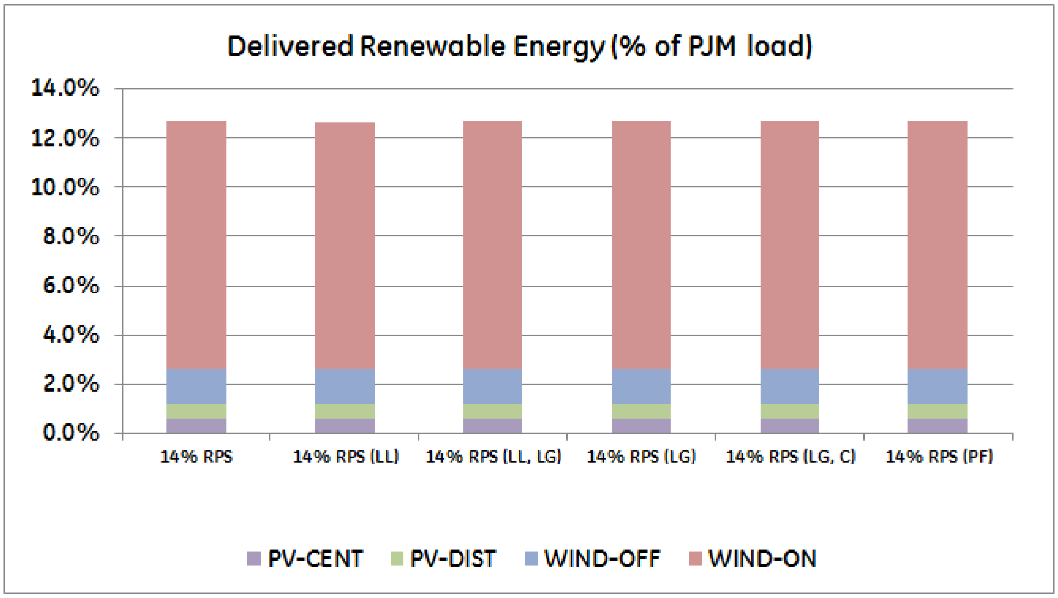

Figure 3-14: 14% RPS Sensitivities – Delivered Renewable Energy

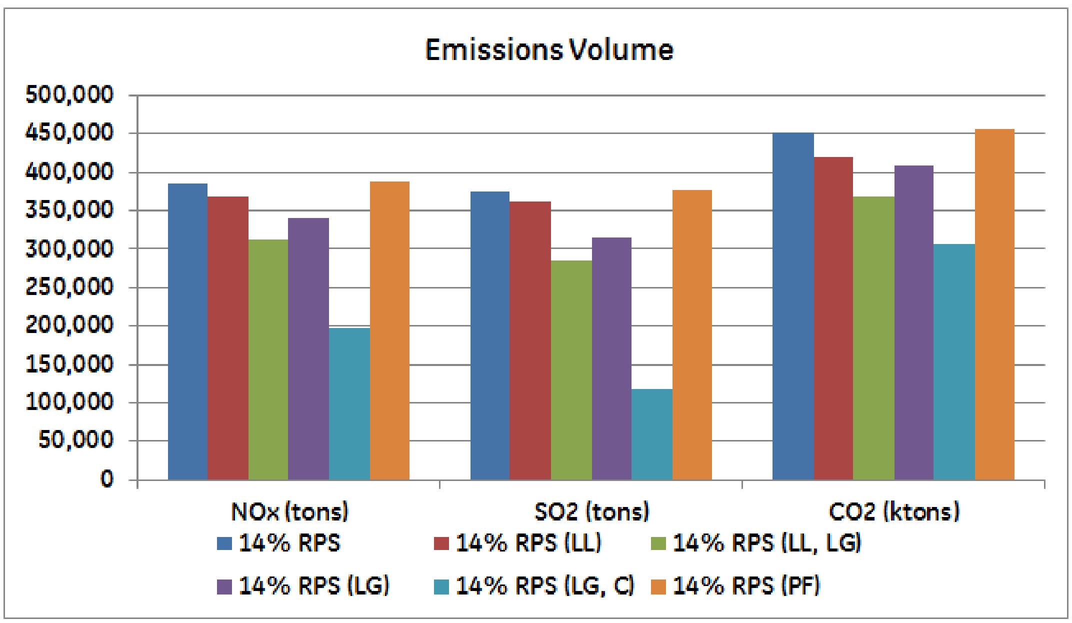

Figure 3-15: 14% RPS Sensitivities – Emissions Volume

3.3.2 14% Unit Performance Sensitivities

Figure 3-16 to Figure 3-7 present unit performances by type. Consistent with previous results, the Coal unit performance indicators exhibit a significant drop in the Low Gas with Carbon Price sensitivity (except for the Number of Starts, which shows a slight rise); the opposite of which is true for CCGT and SCGT units (with CCGT units having fewer starts but longer hours online). The changes are less dramatic but still significant in other sensitivities. The Perfect Forecast sensitivity does not appear to result in any significant change in performance of any of the units types considered.

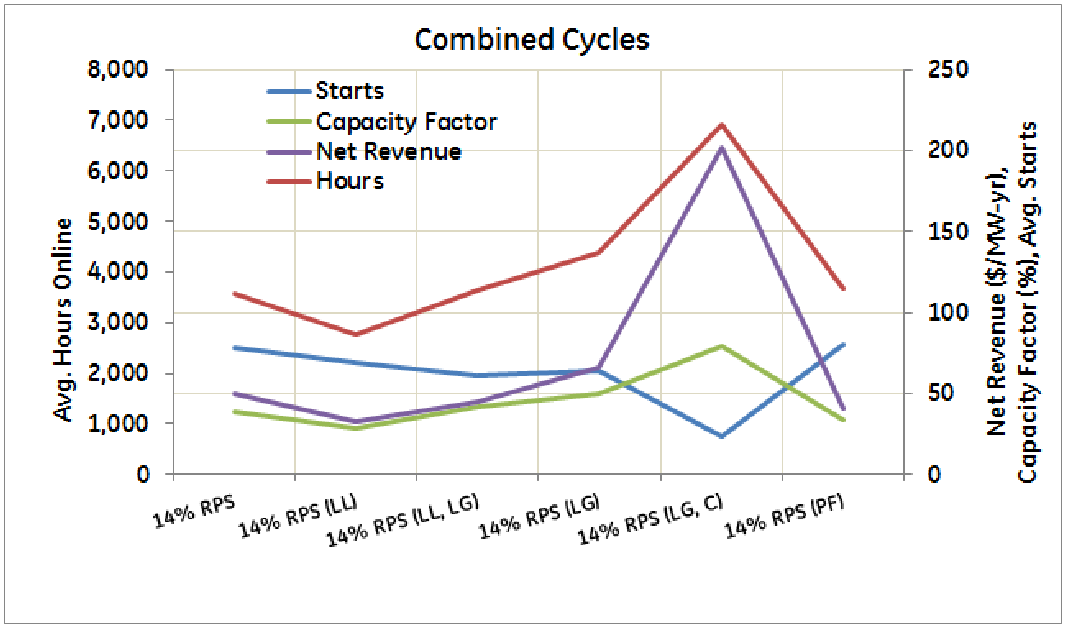

Figure 3-16: 14% RPS Sensitivities – CCGT Performance

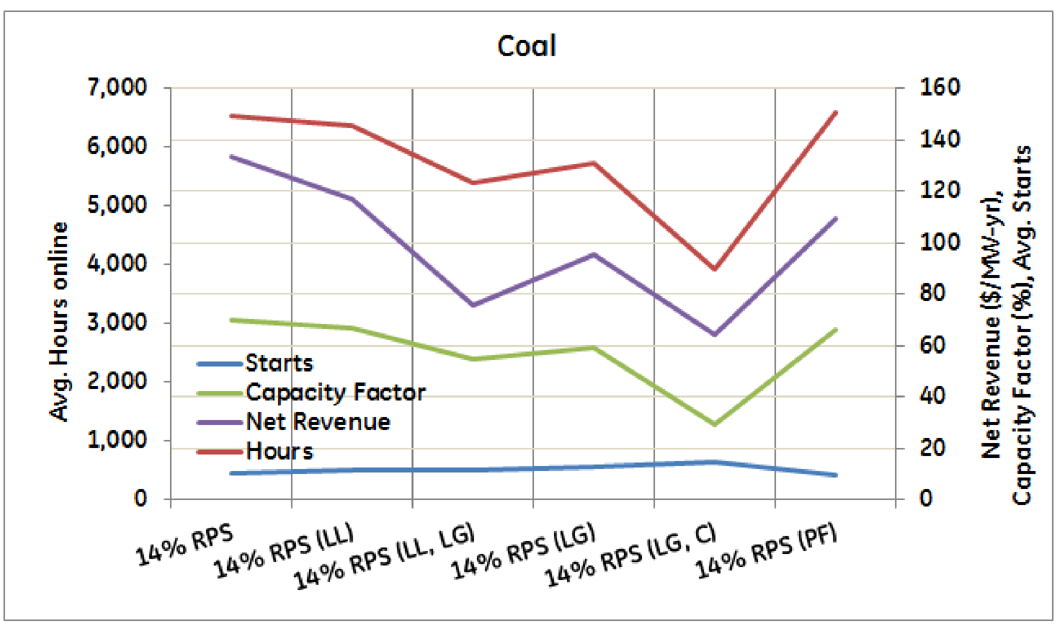

Figure 3-17: 14% RPS Sensitivities – Coal Performance

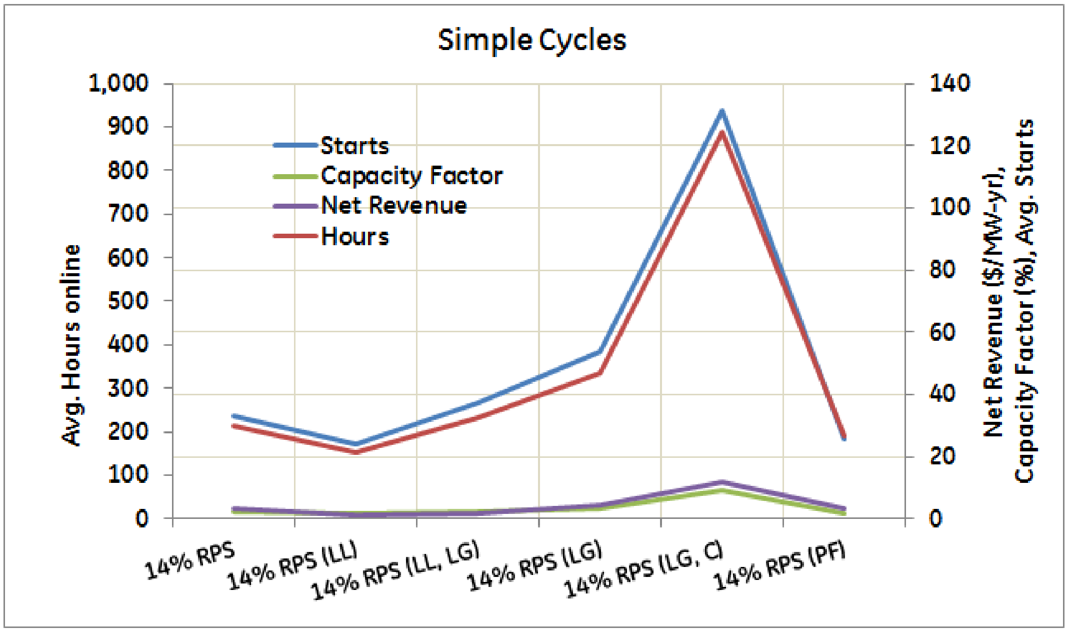

Figure 3-18: 14% RPS Sensitivities – SCGT Performance

3.3.3 14% Economic Performance Sensitivities

Figure 3-19 to Figure 3-22 and Table 3-2 present the economic performance of 14% RPS scenario under different sensitivities. As with the 2% BAU scenario, economic indicators are lowest the Low Load Growth with Low Gas sensitivity results in the lowest value of PJM wide economic indicators, and conversely, the Low Gas with Carbon Price sensitivity results in the highest values of PJ M wind economic indicators.

As shown in Table 3-2, the Perfect Forecast sensitivity results in single digit percentage change in economic indicators compared to the base case. However, there are wide variations in same economic indicators across the other sensitivities. All the other sensitivities, except Low Gas with Carbon Price sensitivity result in lower PJM wide costs, revenues, and prices.

The widest variations in the PJM Wholesale Customer Energy Costs compared to the Base Case are under the Low Load Growth with Lowe Gas sensitivity (a decrease of $12.6B), and under the Low Gas with Carbon Price sensitivity (an increase of $31.1). Relative to the Base Case, the average PJM LMP prices decrease by $9.58/MWh under the Low Load Growth with Low Gas sensitivity, and increase by $33.52/MWh under the Low Gas with High Carbon Price sensitivity.

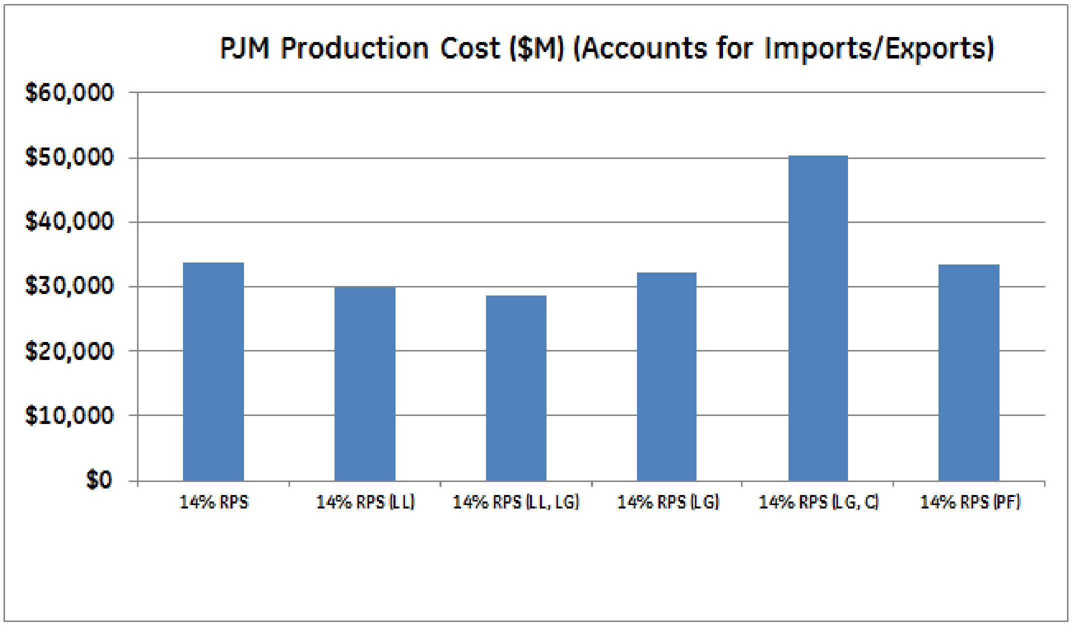

Figure 3-19: 14% RPS Sensitivities – PJM Production Cost

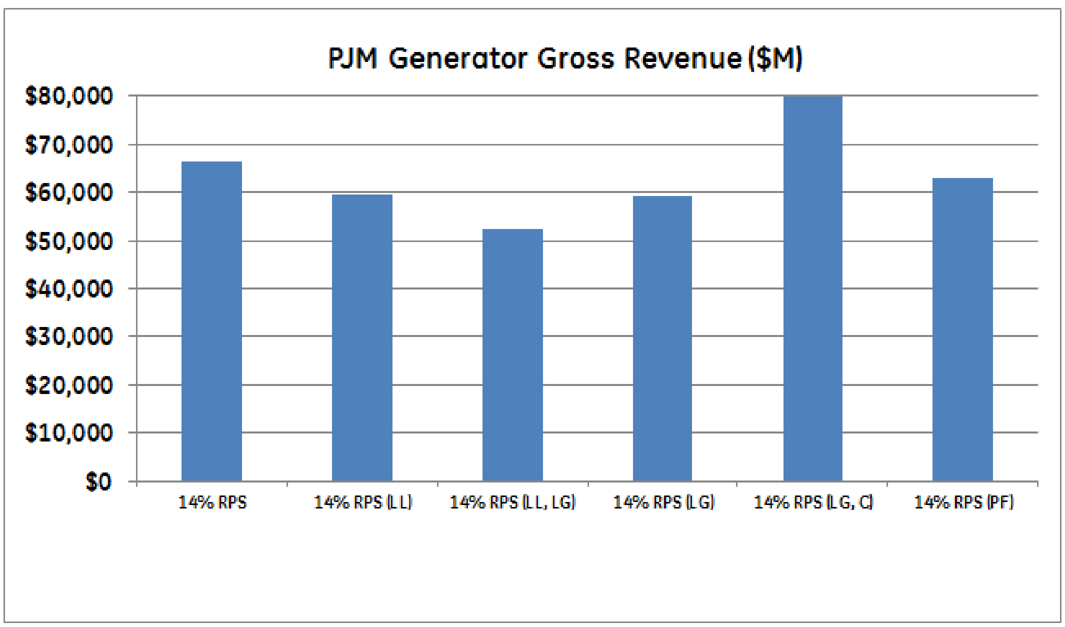

Figure 3-20: 14% RPS Sensitivities – PJM Generator Gross Revenue

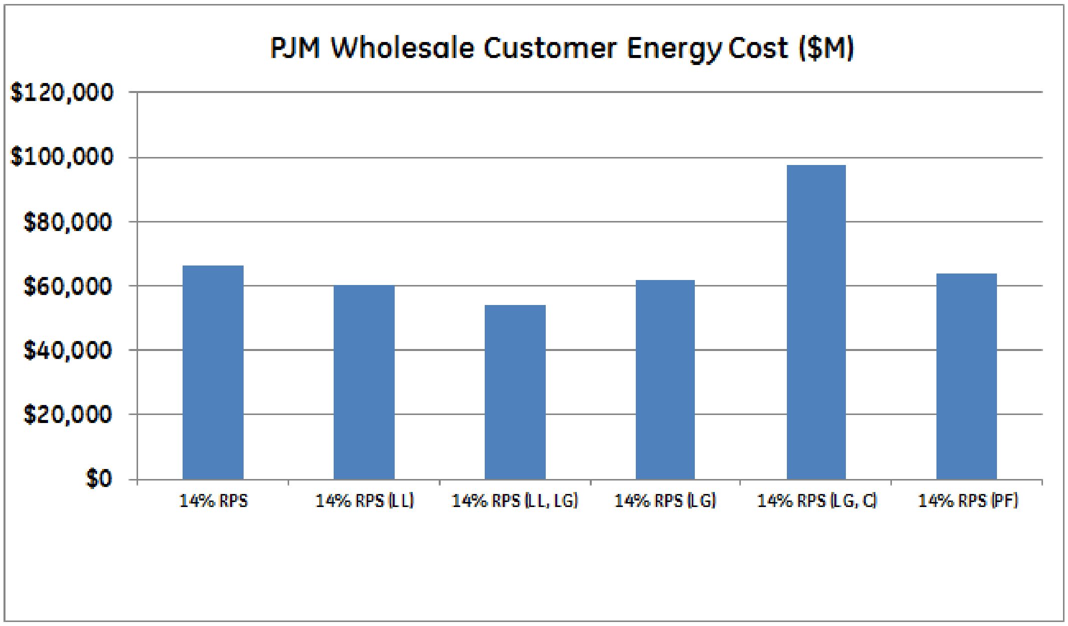

Figure 3-21: 14% RPS Sensitivities – PJM Wholesale Customer Energy Cost

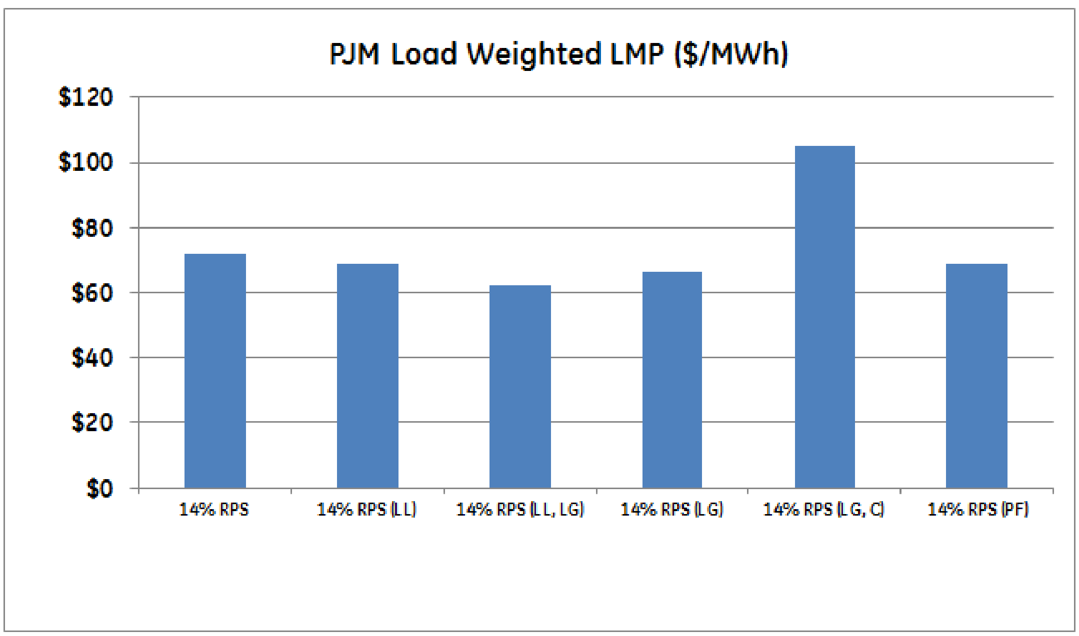

Figure 3-22: 14% RPS Sensitivities – PJM Load Weighted LMP

Table 3-2: Summary of 14% RPS Sensitivities

PJM Sensitivities	14% RPS	14% RPS (LL)	14% RPS (LL, LG)	14% RPS (LG)	14% RPS (LG, C)	14% RPS (PF)
Production Costs ($M)	33,719	29,791	28,482	32,102	50,380	33,470
Change from Base	0	-3,928	-5,237	-1,617	16,660	-250
Relative Change	0.00%	-13.19%	-18.39%	-5.04%	33.07%	-0.75%
Generator Revenue ($M)	66,390	59,628	52,242	59,283	91,473	62,829
Change from Base	0	-6,762	-14,148	-7,107	25,083	-3,561
Relative Change	0.00%	-11.34%	-27.08%	-11.99%	27.42%	-5.67%
Costs to Load ($M)	66,625	60,026	54,054	61,618	97,718	64,026
Change from Base	0	-6,599	-12,571	-5,007	31,093	-2,598
Relative Change	0.00%	-10.99%	-23.26%	-8.13%	31.82%	-4.06%
Load Wtd LMP ($/MWh)	71.8	69.1	62.2	66.4	105.3	69.0
Change from Base	0.0	-2.7	-9.6	-5.4	33.5	-2.8
Relative Change	0.00%	-3.91%	-15.39%	-8.12%	31.82%	-4.05%

3.4 20% LOBO Sensitivities

3.4.1 20% LOBO Operational Performance Sensitivities

Figure 3-23 to Figure 3-26 present the operational performance of 20% LOBO scenario under different sensitivities. The delivered renewable generation remains relatively unchanged under all the sensitivity cases since renewable generation is not subject to dispatch except that it may be curtailed when necessary. As expected, under the Low Load Growth sensitivity, the thermal generation is lower than the base case. Under the Low Load Growth with Low Gas and pure Low Gas sensitivities, coal generation is displaced by CCGT generation.

As with the 2% BAU and 14% scenarios, the most remarkable impact is under the Low Gas with Carbon Price sensitivity. As shown in the figures, there is a significant shift from coal generation to CCGT and SCGT generation, which is reflected in the capacity factor values as well. As expected, lower coal generation also results in a significant drop in emissions volume.

In contrast to the 2% BAU and 14% RPS scenarios, the Perfect Forecast sensitivity appears to have a more significant impact on Coal generation. Apparently, with higher wind penetration, Perfect Forecast results in more optimal commitment of thermal units, resulting in less utilization of Coal, lower onshore wind curtailment. A corresponding impact is a reduction in Emissions Volume.

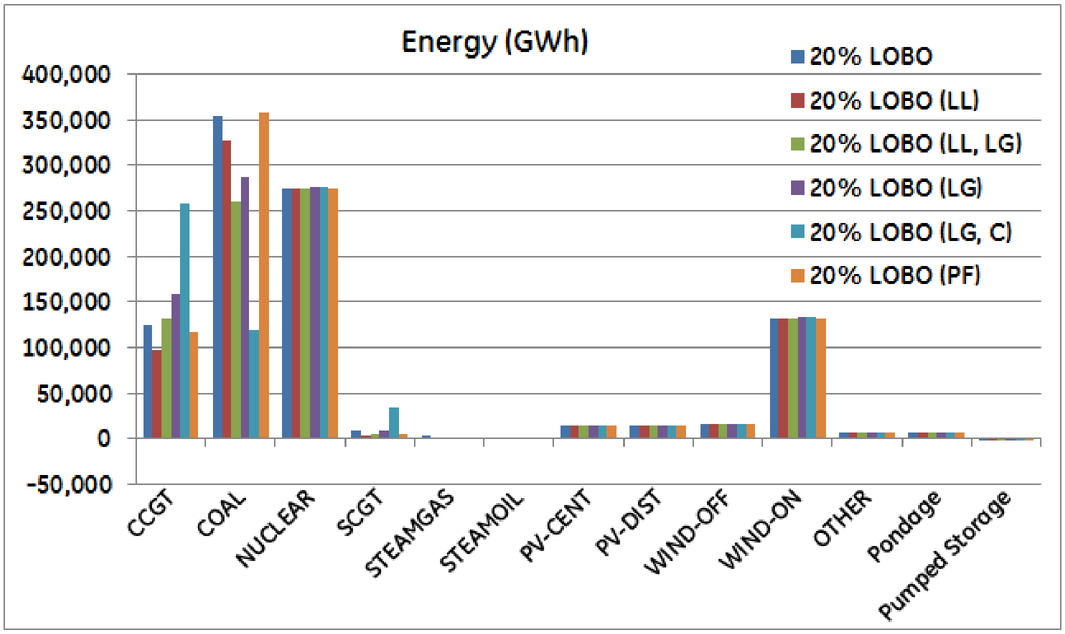

Figure 3-23: 20% LOBO Sensitivities – Energy by Type

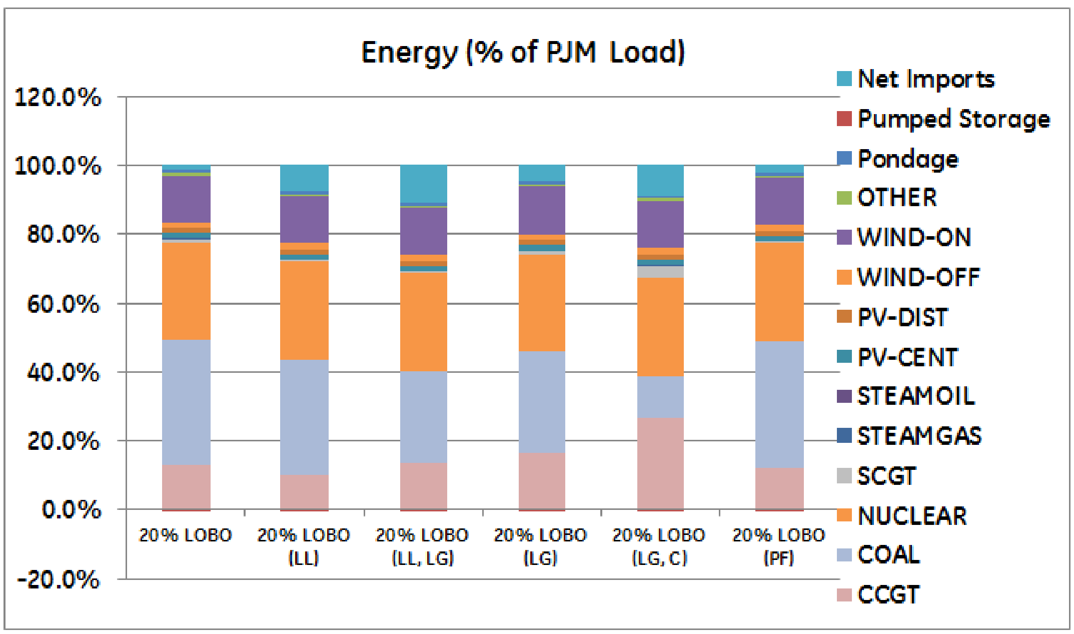

Figure 3-24: 20% LOBO Sensitivities – Energy as % Load

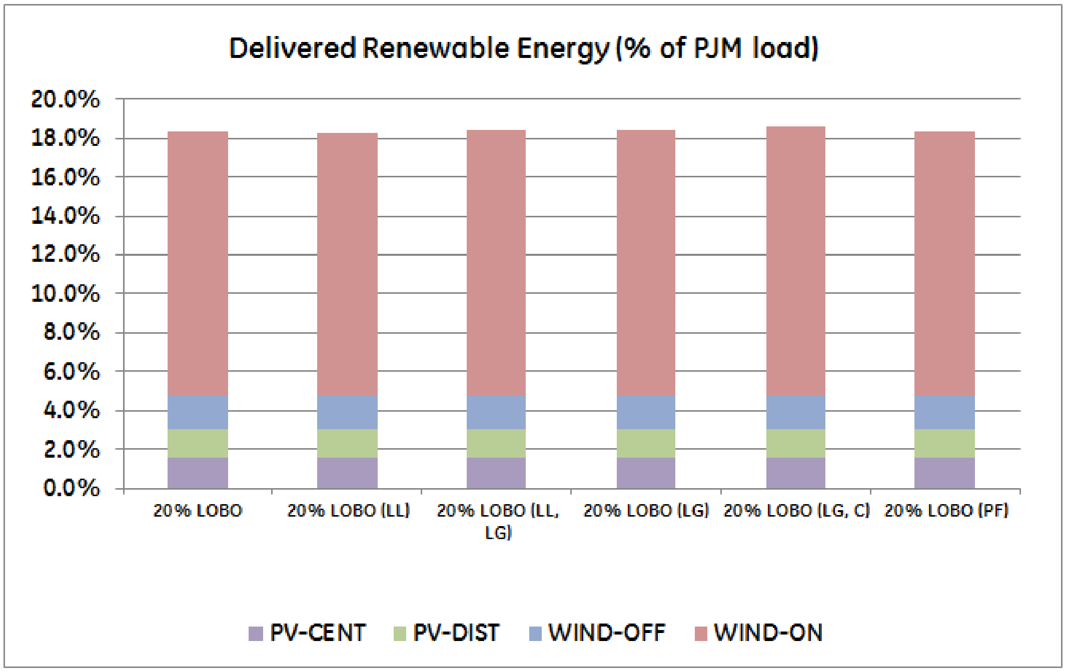

Figure 3-25: 20% LOBO Sensitivities – Delivered Renewable Energy

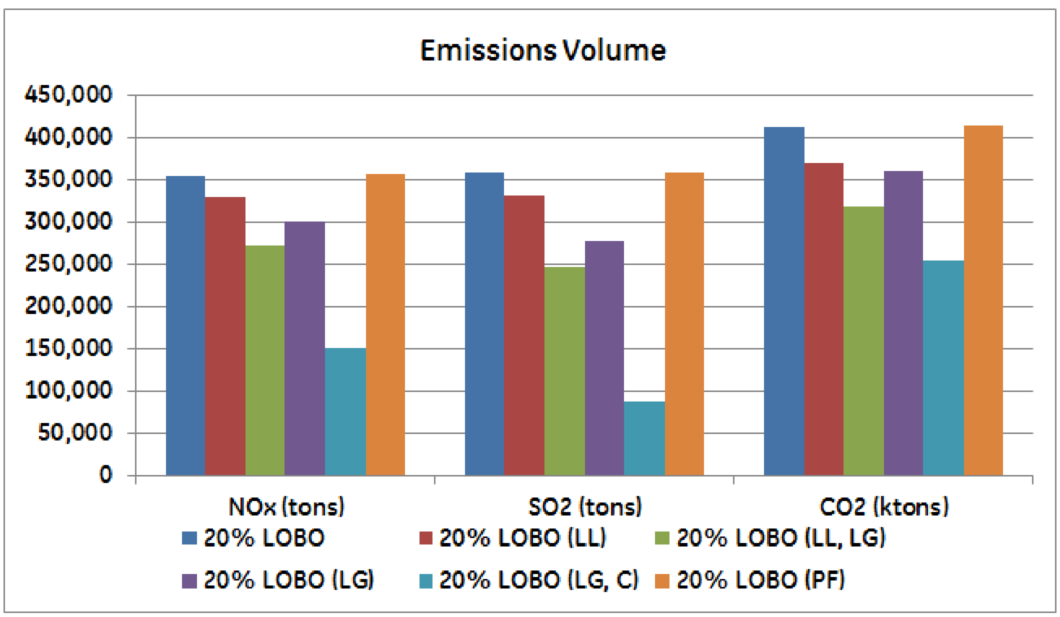

Figure 3-26: 20% LOBO Sensitivities – Emissions Volume

3.4.2 20% LOBO Unit Performance Sensitivities

Figure 3-29 to Figure 3-31 present unit performances by type. Consistent with previous results, the Coal unit performance indicators exhibit a significant drop in the Low Gas with

Carbon Price sensitivity (except for the Number of Starts, which shows a slight rise); the opposite of which is true for CCGT and SCGT units (with CCGT units having fewer starts but longer hours online). The changes are less dramatic but still significant in other sensitivities. The Perfect Forecast sensitivity does not appear to result in any significant change in performance of any of the units types considered.

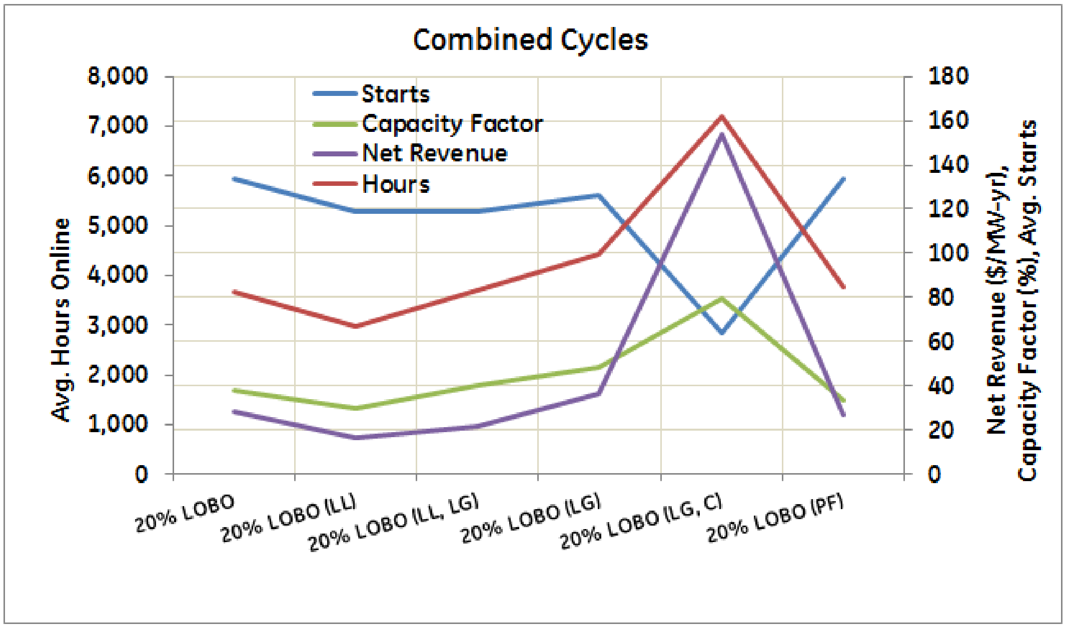

Figure 3-27: 20% LOBO Sensitivities – CCGT Performance

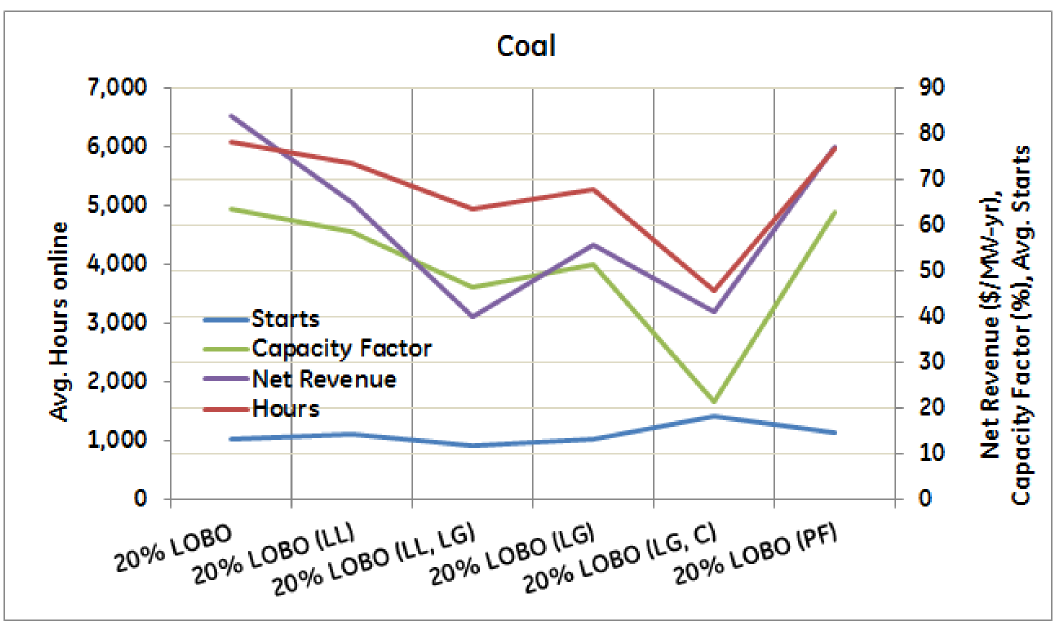

Figure 3-28: 20% LOBO Sensitivities – Coal Performance

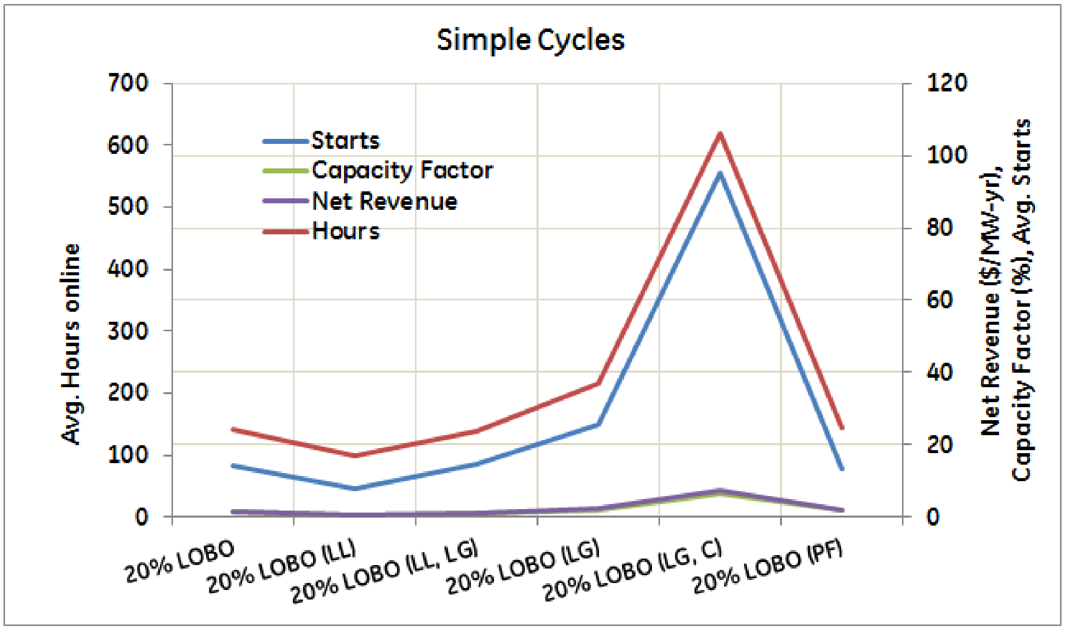

Figure 3-29: 20% LOBO Sensitivities – SCGT Performance

3.4.3 20% LOBO Economic Performance Sensitivities

Figure 3-30 to Figure 3-33 and Table 3-3 present the economic performance of 20% LOBO scenario under different sensitivities. As with the 2% BAU and 14% RPS scenarios, economic indicators are lowest the Low Load Growth with Low Gas sensitivity results in the lowest value of PJM wide economic indicators, and conversely, the Low Gas with Carbon Price sensitivity results in the highest values of PJ M wind economic indicators.

As shown in Table 3-3, the Perfect Forecast sensitivity results in single digit percentage change in economic indicators compared to the base case, except for PJM Production Cost where the drop is about 22.1%. There are wider variations in economic indicators across the other sensitivities. All the other sensitivities, except Low Gas with Carbon Price sensitivity result in lower PJM wide costs, revenues, and prices.

The widest variations in the PJM Wholesale Customer Energy Costs compared to the Base Case are under the Low Load Growth with Lowe Gas sensitivity (a decrease of $13.8B), and under the Low Gas with Carbon Price sensitivity (an increase of $28.9). Relative to the Base Case, the average PJM LMP prices decrease by $11.39/MWh under the Low Load Growth with Low Gas sensitivity, and increase by $31.21/MWh under the Low Gas with High Carbon Price sensitivity.

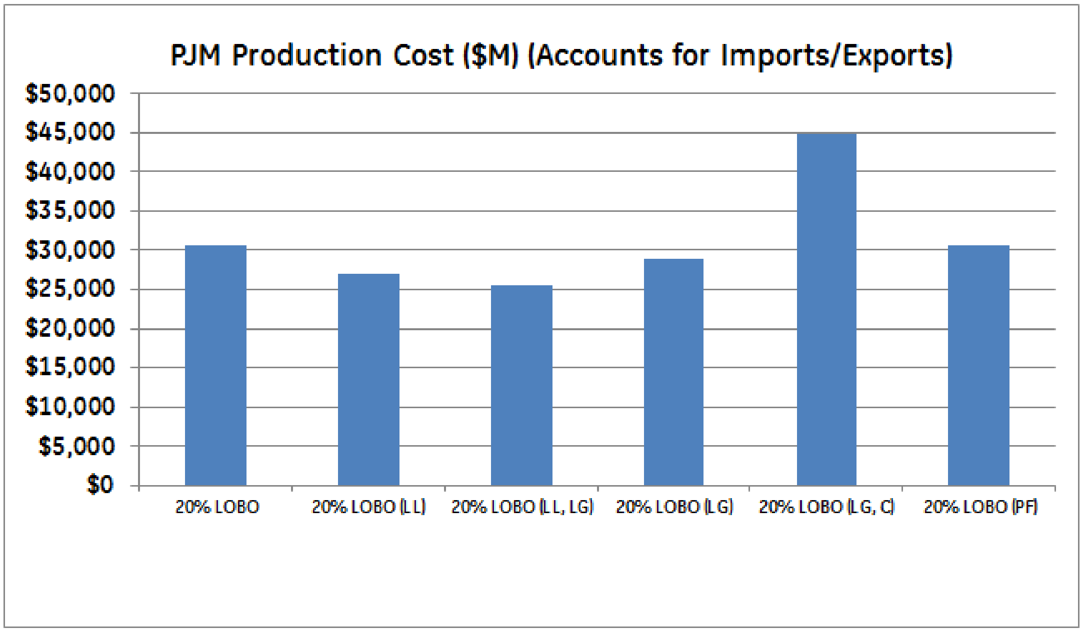

Figure 3-30: 20% LOBO Sensitivities – PJM Production Cost

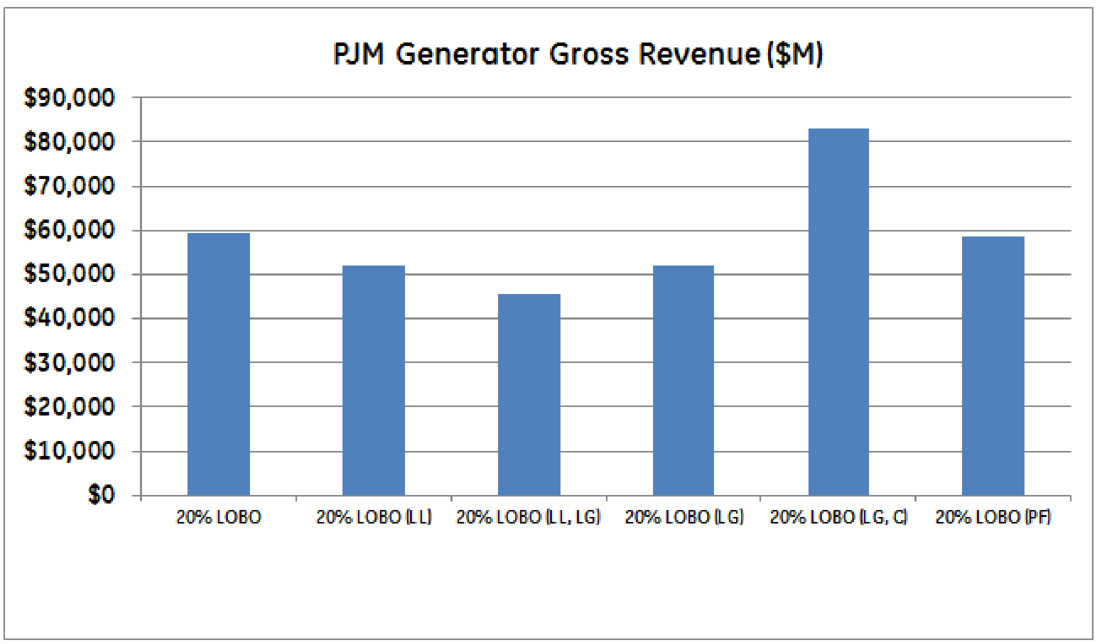

Figure 3-31: 20% LOBO Sensitivities – PJM Generator Gross Revenue

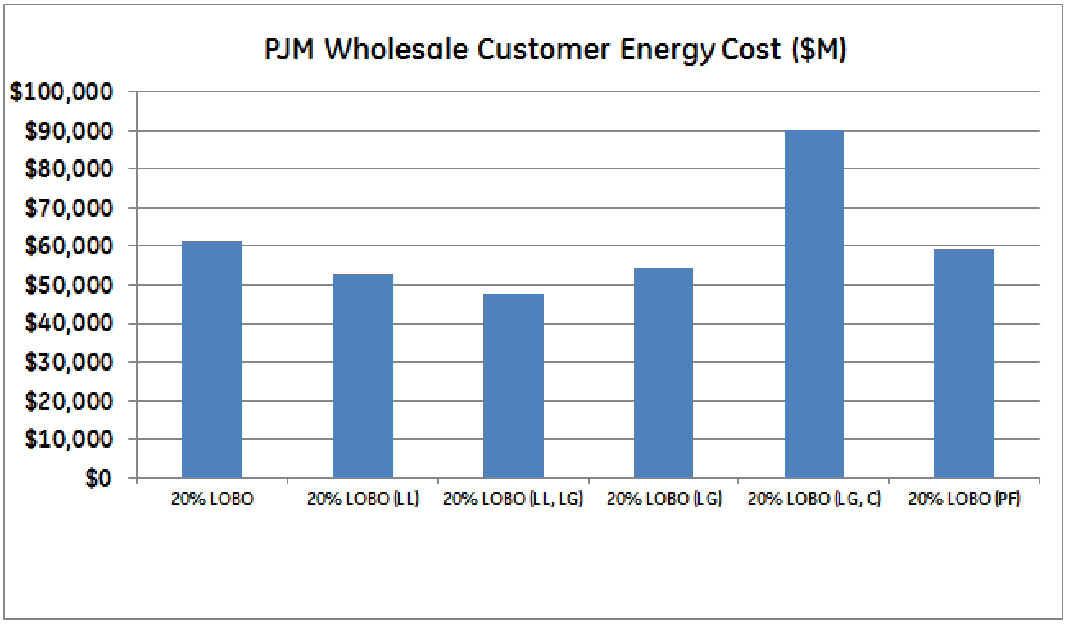

Figure 3-32: 20% LOBO Sensitivities – PJM Wholesale Customer Energy Cost

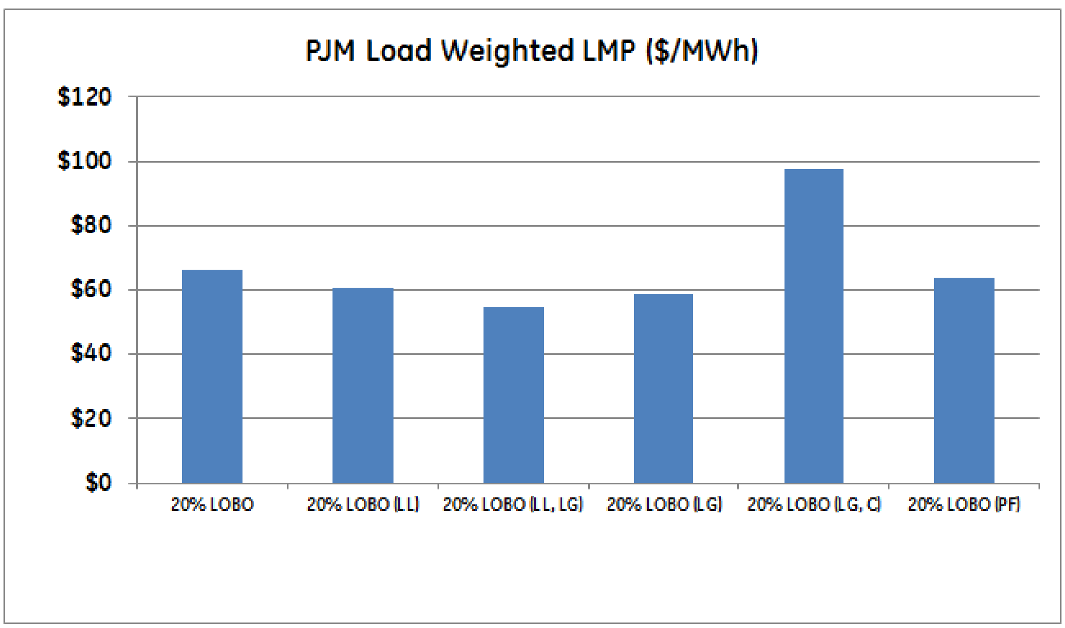

Figure 3-33: 20% LOBO Sensitivities – PJM Load Weighted LMP

Table 3-3: Summary of 20% LOBO Sensitivities

PJM Sensitivities	20% LOBO	20% LOBO (LL)	20% LOBO (LL, LG)	20% LOBO (LG)	20% LOBO (LG, C)	20% LOBO (PF)
Production Costs ($M)	30,610	26,947	25,454	28,879	44,919	30,537
Change from Base	0	-3,663	-5,156	-1,731	14,309	-73
Relative Change	0.00%	-13.59%	-20.26%	-5.99%	31.86%	-0.24%
Generator Revenue ($M)	59,178	52,141	45,549	51,916	82,857	58,725
Change from Base	0	-7,037	-13,629	-7,262	23,679	-453
Relative Change	0.00%	-13.50%	-29.92%	-13.99%	28.58%	-0.77%
Costs to Load ($M)	61,341	52,551	47,541	54,528	90,294	59,197
Change from Base	0	-8,790	-13,800	-6,814	28,952	-2,144
Relative Change	0.00%	-16.73%	-29.03%	-12.50%	32.06%	-3.62%
Load Wtd LMP ($/MWh)	66.1	60.5	54.7	58.8	97.3	63.8
Change from Base	0.0	-5.6	-11.4	-7.3	31.2	-2.3
Relative Change	0.00%	-9.29%	-20.81%	-12.50%	32.06%	-3.63%

3.5 30% LOBO Sensitivities

3.5.1 30% LOBO Operational Performance Sensitivities

Figure 3-34 to Figure 3-37 present the operational performance of 20% LOBO scenario under different sensitivities. The delivered renewable generation remains relatively unchanged under all the sensitivity cases since renewable generation is not subject to dispatch except that it may be curtailed when necessary. As expected, under the Low Load Growth sensitivity, the thermal generation is lower than the base case. Under the Low Load Growth with Low Gas and pure Low Gas sensitivities, coal generation is displaced by CCGT generation.

As with the 2% BAU and 14% scenarios, the most remarkable impact is under the Low Gas with Carbon Price sensitivity. As shown in the figures, there is a significant shift from coal generation to CCGT and SCGT generation, which is reflected in the capacity factor values as well. As expected, lower coal generation also results in a significant drop in emissions volume.

As with the 2% BAU and 14% RPS scenarios, the Perfect Forecast sensitivity does not appear to have a significant impact.

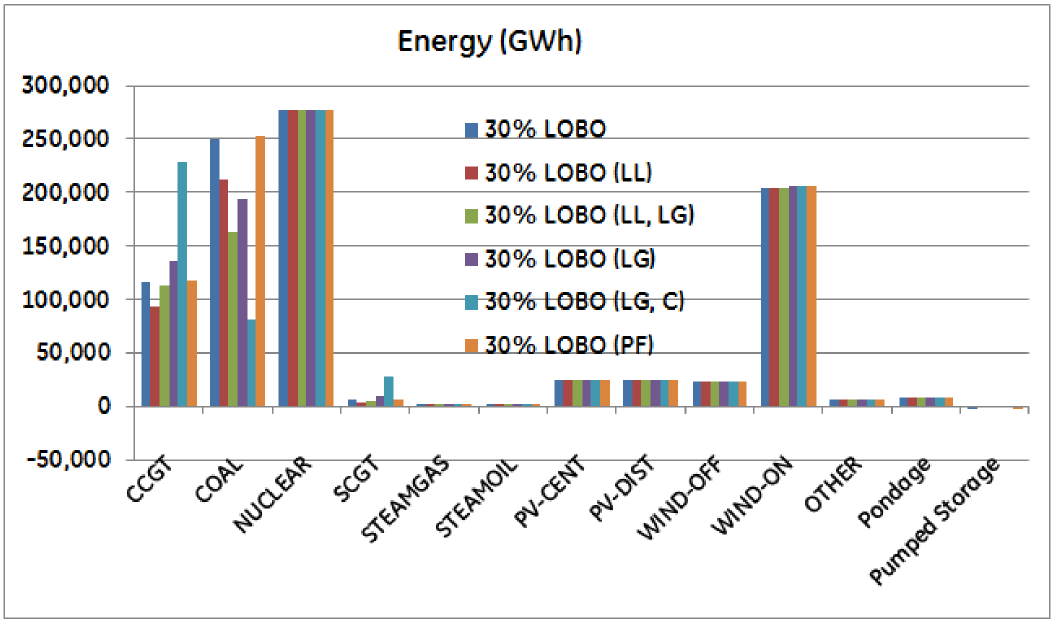

Figure 3-34: 30% LOBO Sensitivities – Energy By Type

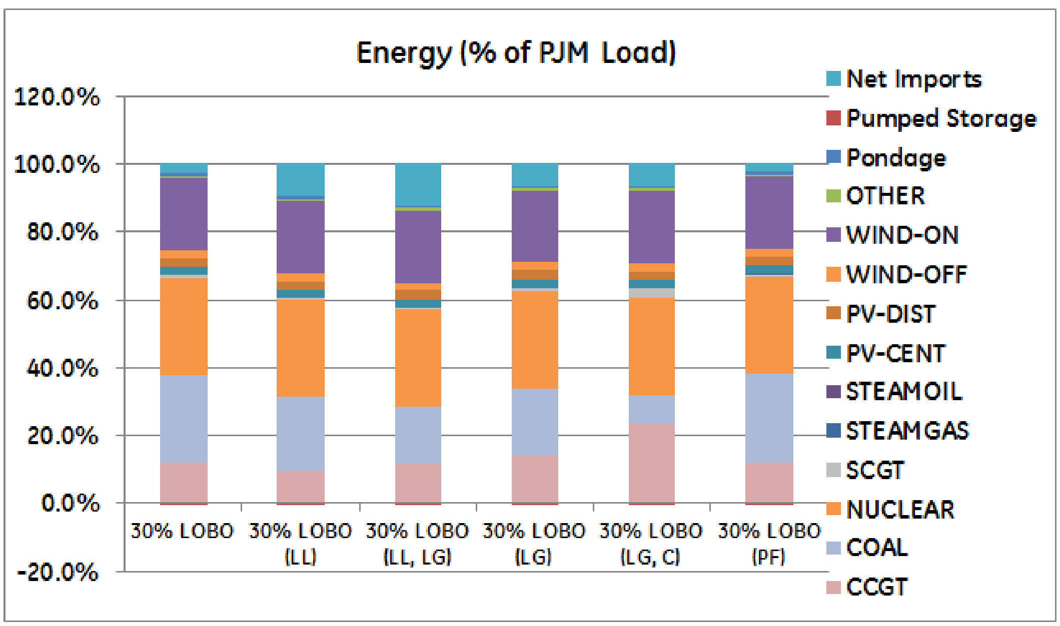

Figure 3-35: 30% LOBO Sensitivities – Energy as % of Load

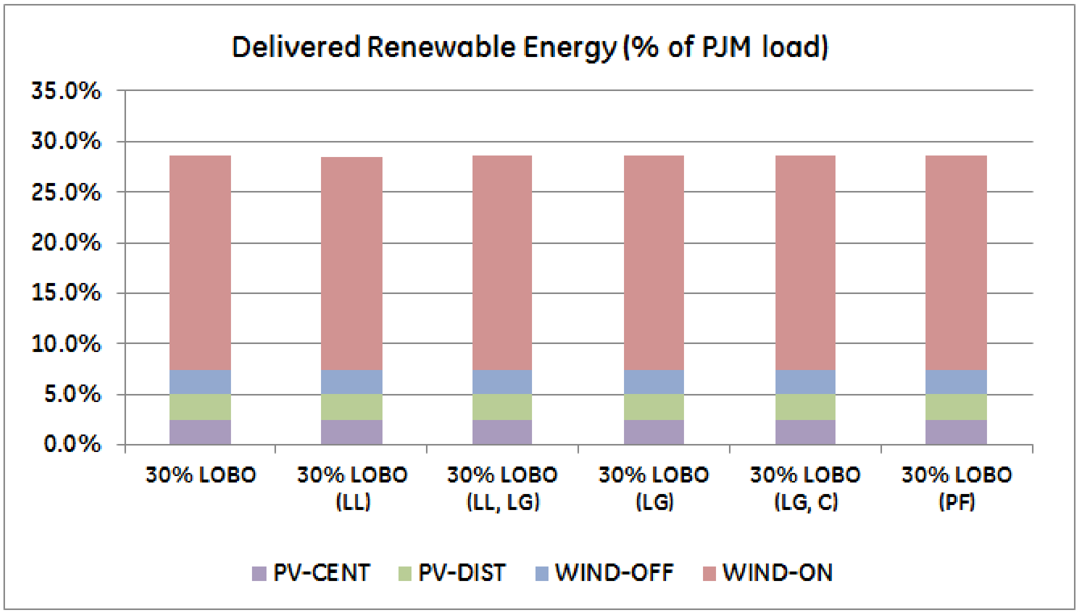

Figure 3-36: 30% LOBO Sensitivities – Delivered Renewable Energy

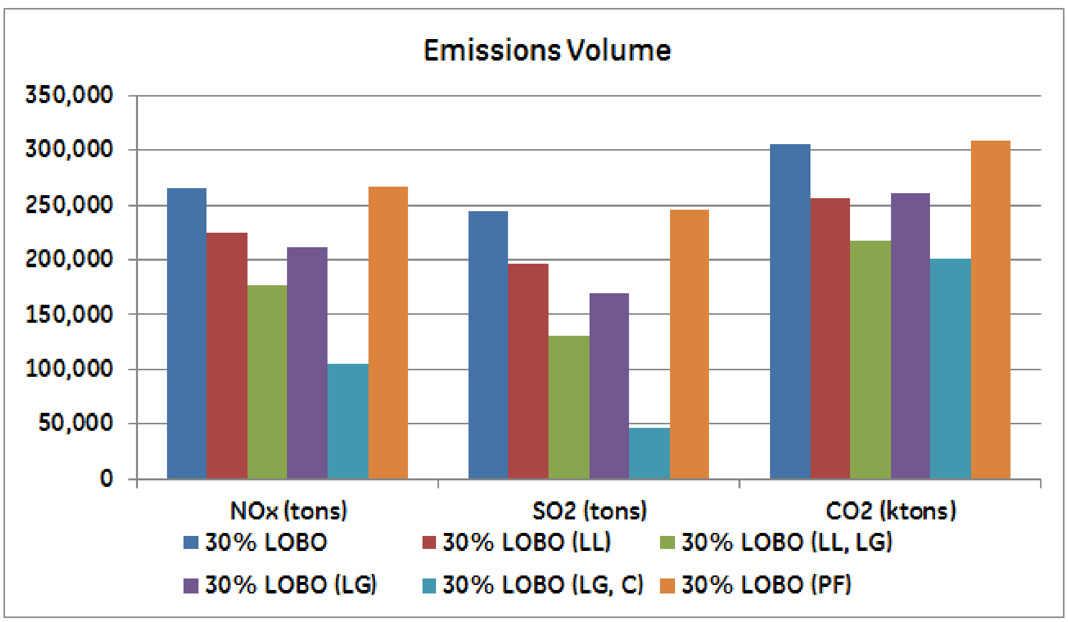

Figure 3-37: 30% LOBO Sensitivities – Emissions Volume

3.5.2 30% LOBO Unit Performance Sensitivities

Figure 3-38 to Figure 3-40 present unit performances by type. Consistent with previous results, the Coal unit performance indicators exhibit a significant drop in the Low Gas with Carbon Price sensitivity (except for the Number of Starts, which shows a slight rise); the opposite of which is true for CCGT and SCGT units (with CCGT units having fewer starts but longer hours online). The changes are less dramatic but still significant in other sensitivities. The Perfect Forecast sensitivity does not appear to result in any significant change in performance of any of the units types considered.

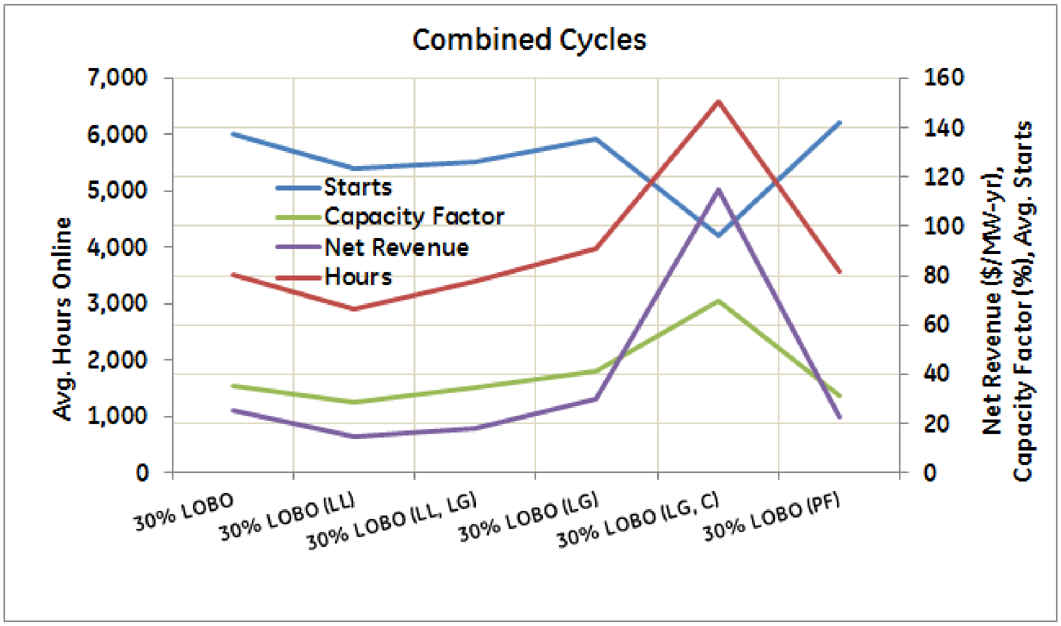

Figure 3-38: 30% LOBO Sensitivities – CCGT Performance

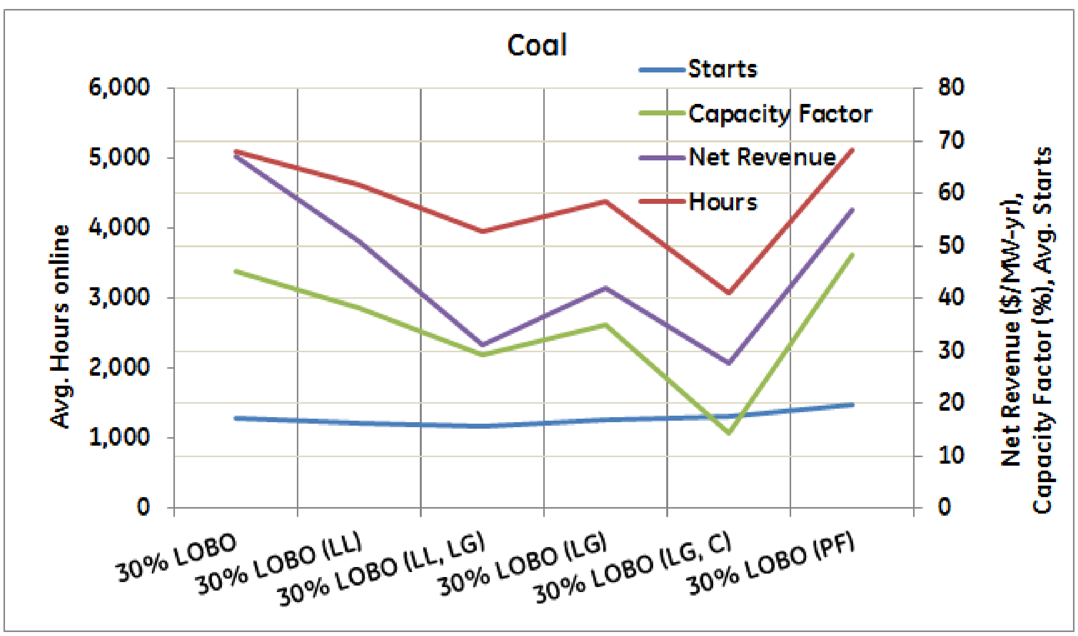

Figure 3-39: 30% LOBO Sensitivities – Coal Performance

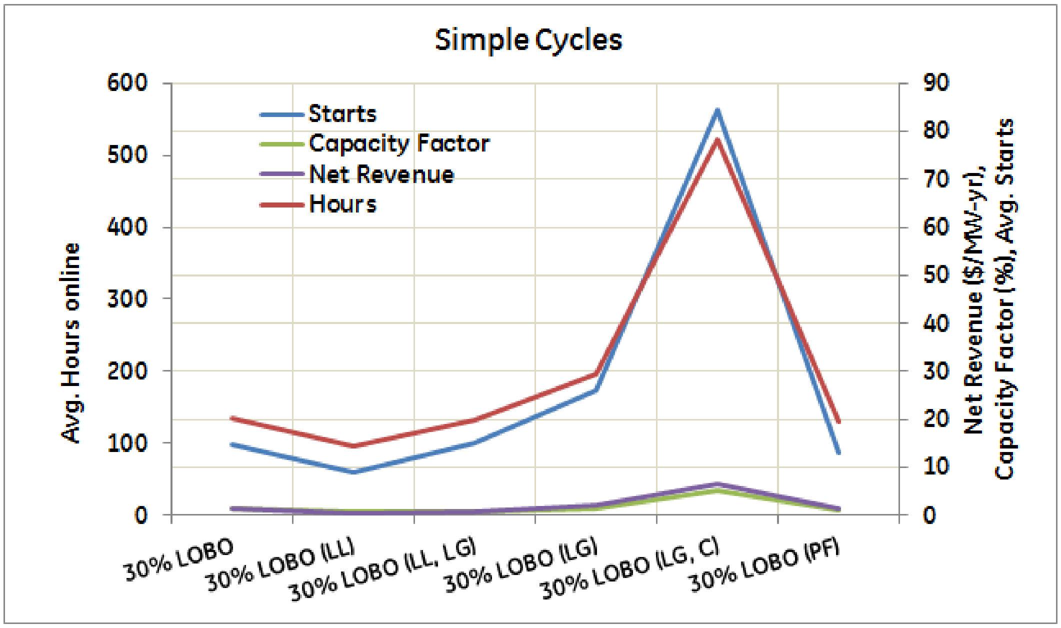

Figure 3-40: 30% LOBO Sensitivities – SCGT Performance

3.5.3 30% LOBO Economic Performance

Figure 3-41 to Figure 3-44Figure 3-33 and Table 3-4 present the economic performance of 30% LOBO scenario under different sensitivities. As with the other scenarios, economic indicators are lowest the Low Load Growth with Low Gas sensitivity results in the lowest value of PJM wide economic indicators, and conversely, the Low Gas with Carbon Price sensitivity results in the highest values of PJ M wind economic indicators.

As shown in Table 3-4, the Perfect Forecast sensitivity results in single digit percentage change in economic indicators compared to the base case. There are wider variations in economic indicators across the other sensitivities. All the other sensitivities, except Low Gas with Carbon Price sensitivity result in lower PJM wide costs, revenues, and prices.

The widest variations in the PJM Wholesale Customer Energy Costs compared to the Base Case are under the Low Load Growth with Lowe Gas sensitivity (a decrease of $13.3B), and under the Low Gas with Carbon Price sensitivity (an increase of $27.4). Relative to the Base Case, the average PJM LMP prices decrease by $10.43/MWh under the Low Load Growth with Low Gas sensitivity, and increase by $28.07/MWh under the Low Gas with High Carbon Price sensitivity.

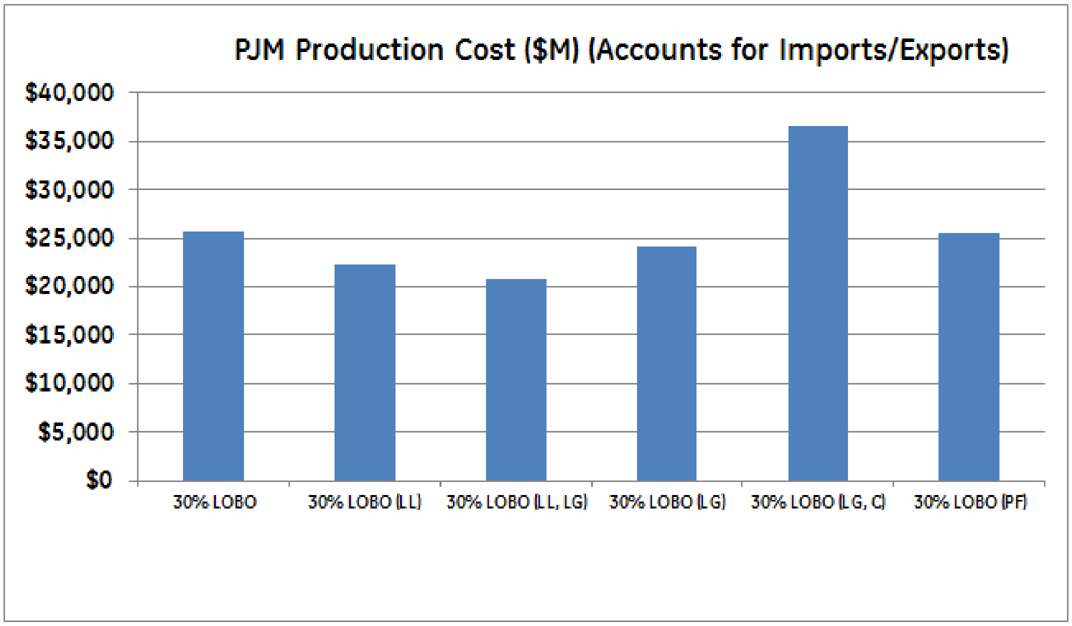

Figure 3-41: 30% LOBO Sensitivities – PJM Production Cost

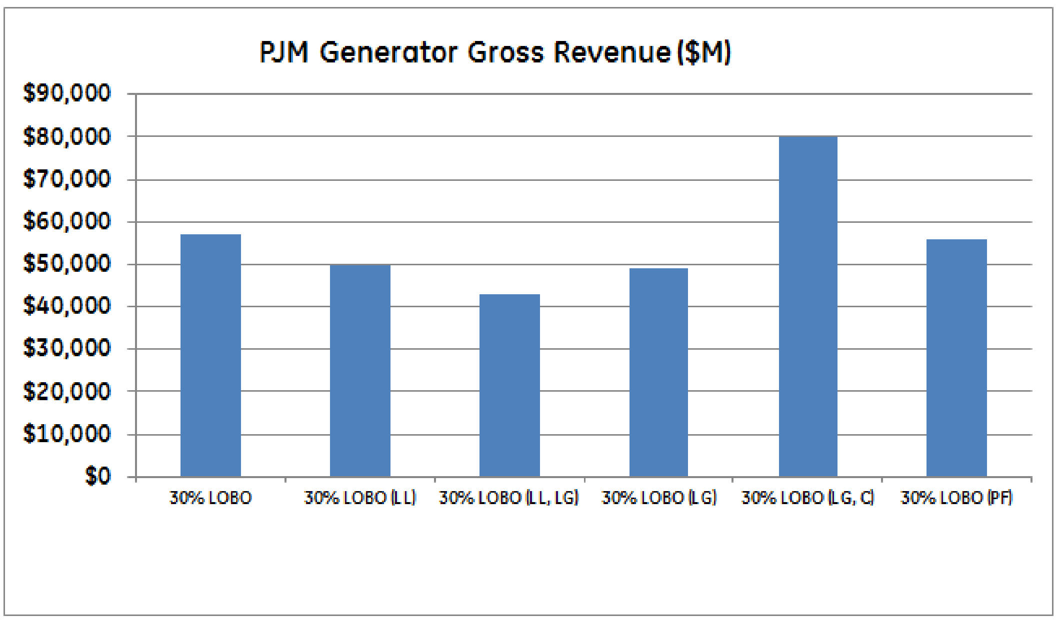

Figure 3-42: 30% LOBO Sensitivities – PJM Generator Gross Revenue

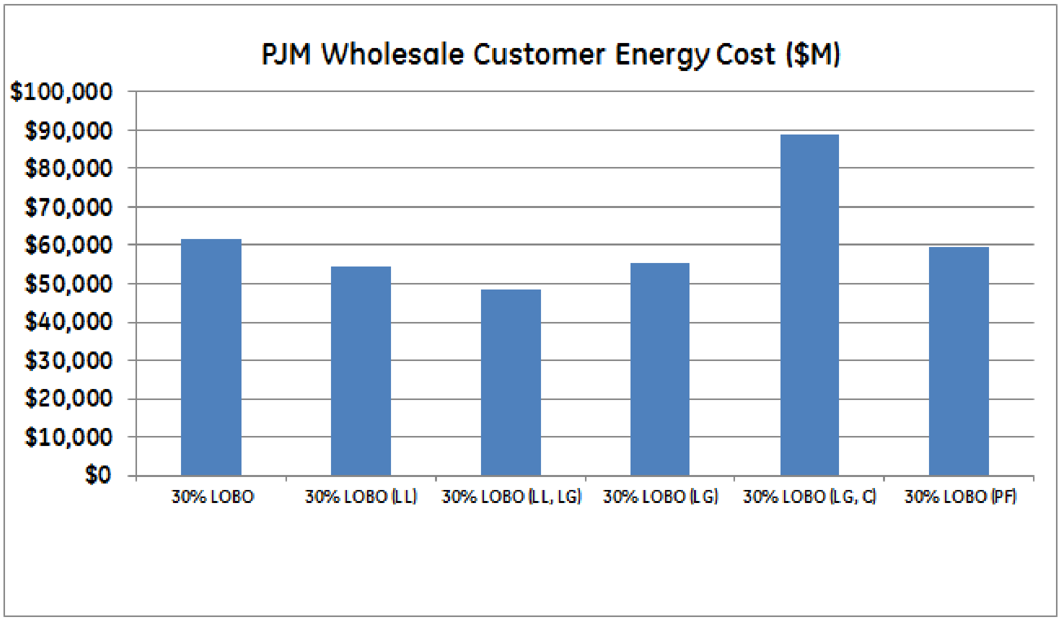

Figure 3-43: 30% LOBO Sensitivities – PJM Wholesale Customer Energy Cost

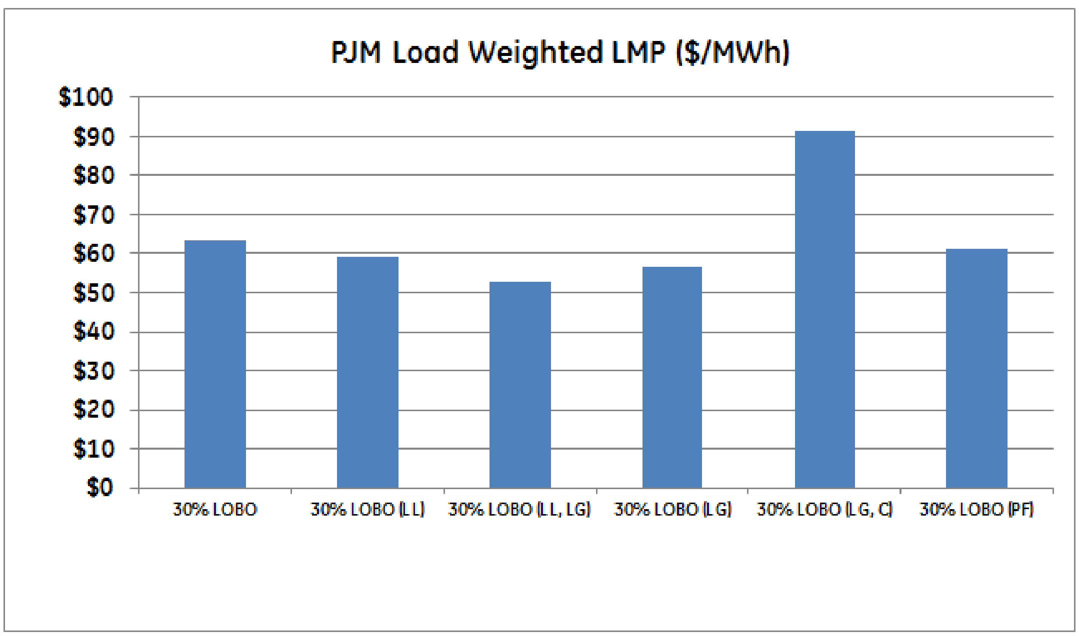

Figure 3-44: 30% LOBO Sensitivities – PJM Load Weighted LMP

Table 3-4: Summary of 30% LOBO Sensitivities

PJM Sensitivities	30% LOBO	30% LOBO (LL)	30% LOBO (LL, LG)	30% LOBO (LG)	30% LOBO (LG, C)	30% LOBO (PF)
Production Costs ($M)	25,708	22,255	20,778	24,092	36,517	25,506
Change from Base	0	-3,452	-4,930	-1,615	10,809	-201
Relative Change	0.00%	-15.51%	-23.72%	-6.71%	29.60%	-0.79%
Generator Revenue ($M)	56,860	49,648	43,001	48,969	79,940	55,769
Change from Base	0	-7,212	-13,859	-7,891	23,079	-1,091
Relative Change	0.00%	-14.53%	-32.23%	-16.11%	28.87%	-1.96%
Costs to Load ($M)	61,635	54,289	48,345	55,156	89,008	59,735
Change from Base	0	-7,346	-13,291	-6,479	27,372	-1,900
Relative Change	0.00%	-13.53%	-27.49%	-11.75%	30.75%	-3.18%
Load Wtd LMP ($/MWh)	63.2	59.3	52.8	56.6	91.3	61.3
Change from Base	0.0	-3.9	-10.4	-6.6	28.1	-2.0
Relative Change	0.00%	-6.65%	-19.76%	-11.75%	30.75%	-3.19%

3.6 Summary of Sensitivity Analysis Results

Table 3-5 to Table 3-10 present the key findings of the sensitivity analysis.

As can be observed from these tables, the economic impacts vary widely depending on the type of the sensitivity and the underlying scenario.

In Table 3-5, compared to the original 2% BAU scenario, production costs are lower in all of the sensitivities except the LG, C sensitivity, with the higher production costs caused by the high carbon price.

Comparing the tables, it can be observed that the range of drops in production costs of 14% RPS scenarios compared to the 2% BAU scenarios is $5.9 B to $9.4 B, within the same sensitivities - i.e., 14% RPS (LL, LG) sensitivity was compared to 2% BAU (LL, LG) sensitivity. These are on top of production cost changes of 2% BAU sensitivities over the original 2% BAU scenario, as shown in Table 3-5.

For instance,), as shown in Table 3-5, the 2% BAU (LL, LG) sensitivity (with lower loads and a natural gas price of $6.50/MMBtu) had a $6.1 B lower production cost compared to the original 2% BAU scenario (with a natural gas price of $8.02/MMBtu. Compared to the 2% BAU (LL, LG) sensitivity, the 14% RPS (LL, LG) sensitivity experienced a production cost drop of $1.6 B, as shown in Table 3-7. In comparison, the production cost in the original 14% RPS scenario was $6.6 B lower than the production cost in the original 2% BAU scenario, as shown in Table 1-2.

Similarly, Table 3-7 shows that going from 2% BAU (LL, LG) sensitivity to 20% LOBO (LL, LG) sensitivity, production cost drops by $8.9 B. This reduction is on top of a production cost drop of $6.1 B, going from the original 2% BAU to 2% BAU (LL, LG) sensitivity, as shown in Table 3-5. In comparison, the production cost in the original 20% LOBO scenario was $9.9 B lower than the production cost in the original 2% BAU scenario, as shown in Table 1-2.

It should be note that although in all sensitivities, the (LG, C) sensitivity (i.e., Low Gas with High Carbon Price sensitivity) results in production cost drop compared to the corresponding 2% BAU (LG, C) sensitivity, there is also a high production cost increase going from the original 2% BAU scenario to 2% BAU (LG, C) sensitivity as shown in Table 3-5.

Table 3-5: Comparison of All BAU Sensitivities

Scenario	Total Non RE Energy (GWh)	Total RE Delivered (GWh)	Total Net Imports (GWh)	Gas Delta (GWh)	Coal Delta (GWh)	Imports Delta (GWh)	Production Cost ($M)	Generator Gross Revenue ($M)	Wholesale Customer Energy Cost ($M)	Load Weighted LMP ($/MWh)
2% BAU	904,998	17,217	47,390	192,025	421,618	47,390	40,470	70,023	70,947	76.5
	Delta with Respect to the 2% BAU Scenario									
2% BAU (LL)	(59,698)	(0)	59,699	(45,723)	(12,919)	59,699	(4,372)	(8,966)	(8,589)	(4.7)
2% BAU (LL, LG)	(90,412)	(0)	90,412	(7,073)	(82,364)	90,412	(6,100)	(16,197)	(13,911)	(10.8)
2% BAU (LG)	(29,852)	(0)	29,852	29,071	(57,433)	29,852	(2,129)	(7,760)	(5,133)	(5.5)
2% BAU (LG, C)	(59,449)	0	59,449	140,102	(195,845)	59,449	19,292	23,328	29,597	31.9
2% BAU (PF)	(213)	(0)	213	199	956	213	(8)	158	848	0.9

Table 3-6: Comparison of Low Load Sensitivities

Scenario	Total Non RE Energy (GWh)	Total RE Delivered (GWh)	Total Net Imports (GWh)	Gas Delta (GWh)	Coal Delta (GWh)	Imports Delta (GWh)	Production Cost ($M)	Generator Gross Revenue ($M)	Wholesale Customer Energy Cost ($M)	Load Weighted LMP ($/MWh)	Production Cost Savings ($/MWh RE)
2% BAU (LL)	845,300	17,217	107,089	146,302	408,699	107,089	36,099	61,057	62,358	71.8	
	Delta with Respect to 2% BAU (LL) Scenario										Relative to the 2% BAU (LL) Scenario
14% RPS (LL)	(76,524)	105,328	(28,804)	(40,971)	(35,247)	(28,804)	(6,307)	(1,430)	(2,333)	(2.7)	59.9
20% LOBO (LL)	(127,972)	159,638	(31,665)	(43,109)	(81,441)	(31,665)	(9,151)	(8,916)	(9,807)	(11.3)	57.3
30% LOBO (LL)	(245,358)	258,611	(13,252)	(49,052)	(196,297)	(13,252)	(13,843)	(11,409)	(8,069)	(12.5)	53.5

Table 3-7: Comparison of Low Load + Low Natural Gas Prices Sensitivities

Scenario	Total Non RE Energy (GWh)	Total RE Delivered (GWh)	Total Net Imports (GWh)	Gas Delta (GWh)	Coal Delta (GWh)	Imports Delta (GWh)	Production Cost ($M)	Generator Gross Revenue ($M)	Wholesale Customer Energy Cost ($M)	Load Weighted LMP ($/MWh)	Production Cost Savings ($/MWh RE)
2% BAU (LL, LG)	814,586	17,216	137,802	184,952	339,254	137,802	34,370	53,826	57,036	65.7	
	Delta with Respect to the 2% BAU (LL, LG) Scenario										Relative to the 2% BAU (LL, LG) Scenario
14% RPS (LL, LG)	(73,278)	105,717	(32,439)	(37,527)	(35,426)	(32,439)	(5,888)	(1,585)	(2,982)	(3.4)	55.7
20% LOBO (LL, LG)	(129,955)	161,216	(31,262)	(47,615)	(79,887)	(31,262)	(8,916)	(8,277)	(9,495)	(10.9)	55.3
30% LOBO (LL, LG)	(241,424)	259,642	(18,218)	(65,977)	(175,857)	(18,218)	(13,592)	(10,826)	(8,691)	(12.9)	52.4

Table 3-8: Comparison of Low Natural Gas Sensitivities

Scenario	Total Non RE Energy (GWh)	Total RE Delivered (GWh)	Total Net Imports (GWh)	Gas Delta (GWh)	Coal Delta (GWh)	Imports Delta (GWh)	Production Cost ($M)	Generator Gross Revenue ($M)	Wholesale Customer Energy Cost ($M)	Load Weighted LMP ($/MWh)	Production Cost Savings ($/MWh RE)
2% BAU (LG)	875,145	17,217	77,243	221,096	364,185	77,243	38,341	62,263	65,814	70.9	
	Delta with Respect to the 2% BAU (LG) Scenario										Relative to the 2% BAU (LG) Scenario
14% RPS (LG)	(75,727)	105,806	(30,080)	(39,785)	(35,847)	(30,080)	(6,239)	(2,981)	(4,197)	(4.5)	59.0
20% LOBO (LG)	(132,052)	161,906	(29,855)	(52,492)	(77,874)	(29,855)	(9,462)	(10,347)	(11,287)	(12.2)	58.4
30% LOBO (LG)	(245,446)	260,271	(14,825)	(76,131)	(170,133)	(14,825)	(14,249)	(13,294)	(10,658)	(14.4)	54.7

Table 3-9: Comparison of Low Natural Gas Prices + High Carbon Price Sensitivities

Scenario	Total Non RE Energy (GWh)	Total RE Delivered (GWh)	Total Net Imports (GWh)	Gas Delta (GWh)	Coal Delta (GWh)	Imports Delta (GWh)	Production Cost ($M)	Generator Gross Revenue ($M)	Wholesale Customer Energy Cost ($M)	Load Weighted LMP ($/MWh)	Production Cost Savings ($/MWh RE)
2% BAU (LG, C)	845,548	17,217	106,839	332,128	225,773	106,839	59,763	93,352	100,545	108.4	
	Delta with Respect to the 2% BAU (LG, C) Scenario										Relative to the 2% BAU (LG, C) Scenario
14% RPS (LG, C)	(84,213)	105,928	(21,715)	(23,519)	(63,182)	(21,715)	(9,383)	(1,878)	(2,827)	(3.0)	88.6
20% LOBO (LG, C)	(142,725)	163,088	(20,363)	(37,703)	(106,978)	(20,363)	(14,844)	(10,495)	(10,251)	(11.1)	91.0
30% LOBO (LG, C)	(215,763)	260,898	(45,135)	(74,370)	(145,102)	(45,135)	(23,246)	(13,412)	(11,537)	(17.1)	89.1

Table 3-10: Comparison of Perfect Forecast Sensitivities

Scenario	Total Non RE Energy (GWh)	Total RE Delivered (GWh)	Total Net Imports (GWh)	Gas Delta (GWh)	Coal Delta (GWh)	Imports Delta (GWh)	Production Cost ($M)	Generator Gross Revenue ($M)	Wholesale Customer Energy Cost ($M)	Load Weighted LMP ($/MWh)	Production Cost Savings ($/MWh RE)
2% BAU (PF)	904,785	17,217	47,603	192,225	422,573	47,603	40,462	70,182	71,795	77.4	
	Delta with Respect to the 2% BAU (PF) Scenario										Relative to the 2% BAU (PF) Scenario
14% RPS (PF)	(80,147)	105,465	(25,318)	(49,251)	(30,518)	(25,318)	(6,993)	(7,353)	(7,768)	(8.4)	66.3
20% LOBO (PF)	(123,699)	160,875	(37,176)	(53,318)	(67,577)	(37,176)	(9,925)	(11,456)	(12,598)	(13.6)	61.7
30% LOBO (PF)	(236,280)	260,139	(23,859)	(66,287)	(170,096)	(23,859)	(14,956)	(14,413)	(12,060)	(16.1)	57.5

Overall, the sensitivity analysis revealed the following trends:

- Lower load growth caused a reduction of both coal and gas generation, resulting in lower production costs and average LMPs.
- Lower natural gas price caused an increase in gas-fired generation and a decrease in coal generation, also resulting in lower production costs and average LMPs.
- Lower natural gas price with increased carbon cost caused a dramatic decrease in coal generation and a significant increase in CCGT and SCGT operation. With the carbon price included in the variable operating costs, total production costs and LMPs and load costs all increased by about 30% relative to the baseline assumptions.
- Lower load growth with lower natural gas price resulted in a reduction in coal generation, with minimal impact on the energy production of other generation resources.
- Perfect renewable forecast appeared to result in relatively small decrease in economic variables compared to the other sensitivities.
- Production cost savings from renewable energy can vary significantly depending on assumptions about fuel prices, load growth, and emission costs. For example, as shown in Table 3-11, compared to the base scenario, production cost savings in the 14% RPS scenario were 12.8% lower for the Low Load / Low Gas sensitivity and 39% higher for the Low Gas / High Carbon sensitivity.

Table 3-11: Impact of Sensitivities on Production Costs

	Base	(LL)	(LL, LG)	(LG)	(LG, C)	(PF)
Production Costs($M)						
2% BAU	40,470	36,099	34,370	38,341	59,763	40,462
14% RPS	33,719	29,791	28,482	32,102	50,380	33,470
20% LOBO	30,610	26,947	25,454	28,879	44,919	30,537
30% LOBO	25,708	22,255	20,778	24,092	36,517	25,506
Delta Relative to 2% BAU						
2% BAU	0	0	0	0	0	0
14% RPS	-6,751	-6,307	-5,888	-6,239	-9,383	-6,993
20% LOBO	-9,860	-9,151	-8,916	-9,462	-14,844	-9,925
30% LOBO	-14,763	-13,843	-13,592	-14,249	-23,246	-14,956
Compared to the Base Case						
2% BAU	-	-	-	-	-	-
14% RPS	-	-6.6%	-12.8%	-7.6%	39.0%	3.6%
20% LOBO	-	-7.2%	-9.6%	-4.0%	50.5%	0.7%
30% LOBO	-	-6.2%	-7.9%	-3.5%	57.5%	1.3%

3.7 Production Cost Savings Due to Renewables under Sensitivity Assumptions

Figure 3-45 to Figure 3-49 depict the contribution of renewables in terms of production cost savings per MWh of additional renewables relative to the corresponding 2% BAU scenario sensitivity. The values correspond to the last columns of Table 3-6 to Table 3-10.

As can be expected, the (LL, LG) sensitivity results in the lowest set of production cost savings - from \$52.4/MWh RE to \$55.7/MWh RE. This is because in the (LL, LG) sensitivity, the less costly thermal energy is replaced by renewable energy. In contrast, the highest set of production cost savings - from \$88.6/MWh RE to \$91.0/MWh RE - is in the (LG, C) sensitivity. This is because in the (LG, C) sensitivity, more costly thermal energy is replaced by renewable energy.

Again, it should be noted that these are "average" production cost savings associated with the impact of total amount of renewable energy, and not the "marginal" value associated with the last MWh of renewable energy.

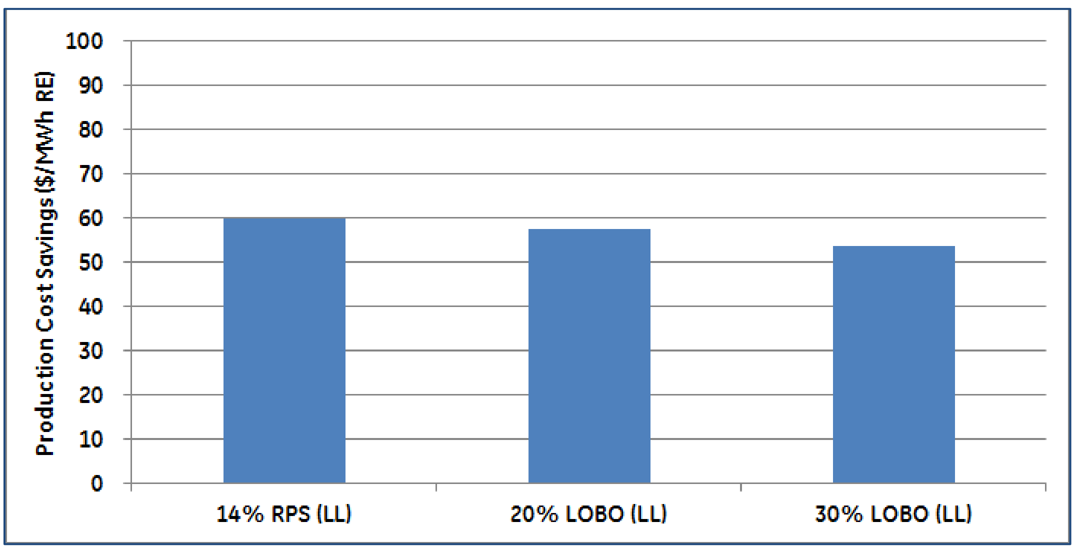

Figure 3-45: Production Cost Savings of (LL) Sensitivities over 2% BAU per MWh Renewable Additions

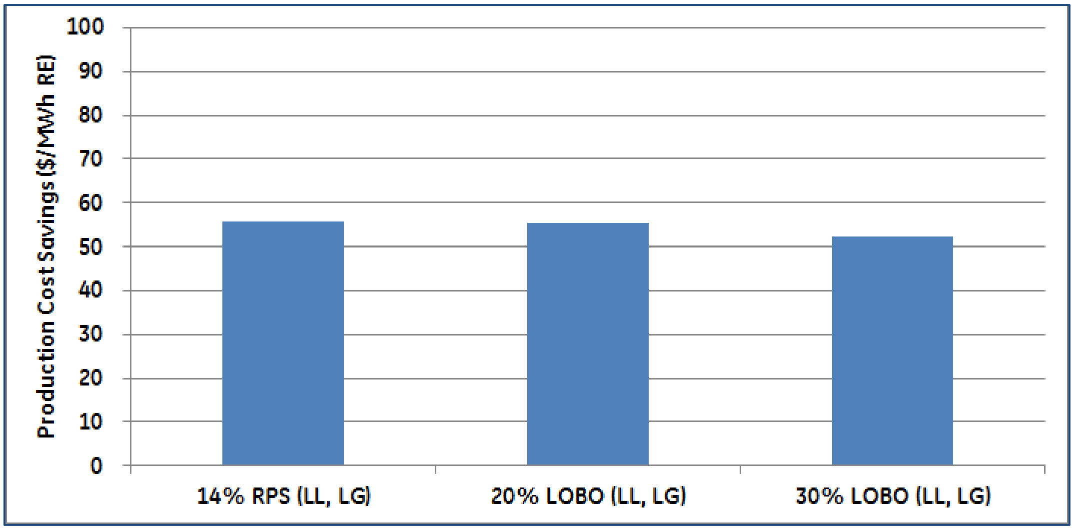

Figure 3-46: Production Cost Savings of (LL, LG) Sensitivities over 2% BAU per MWh Renewable Additions

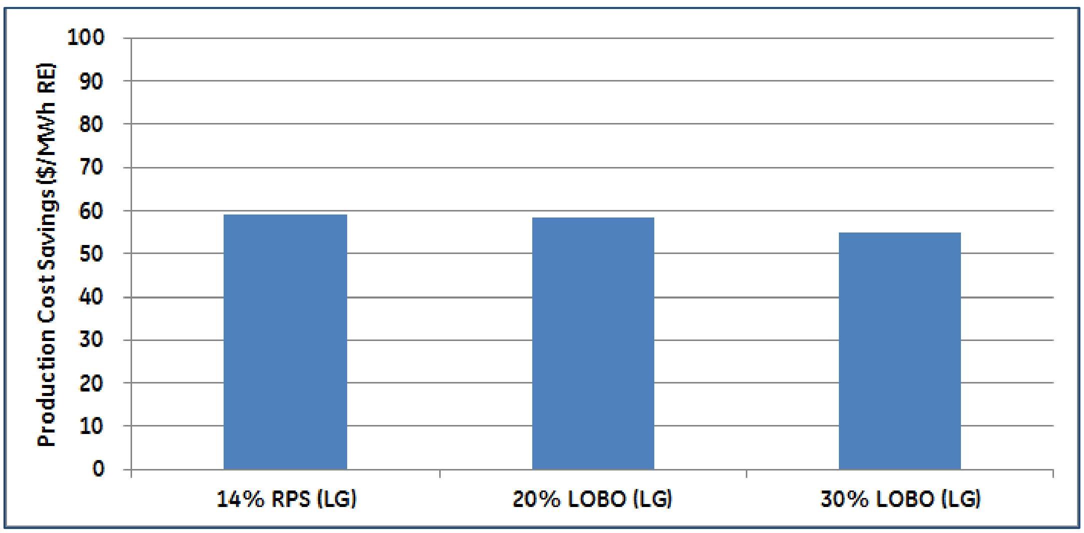

Figure 3-47: Production Cost Savings of (LG) Sensitivities over 2% BAU per MWh Renewable Additions

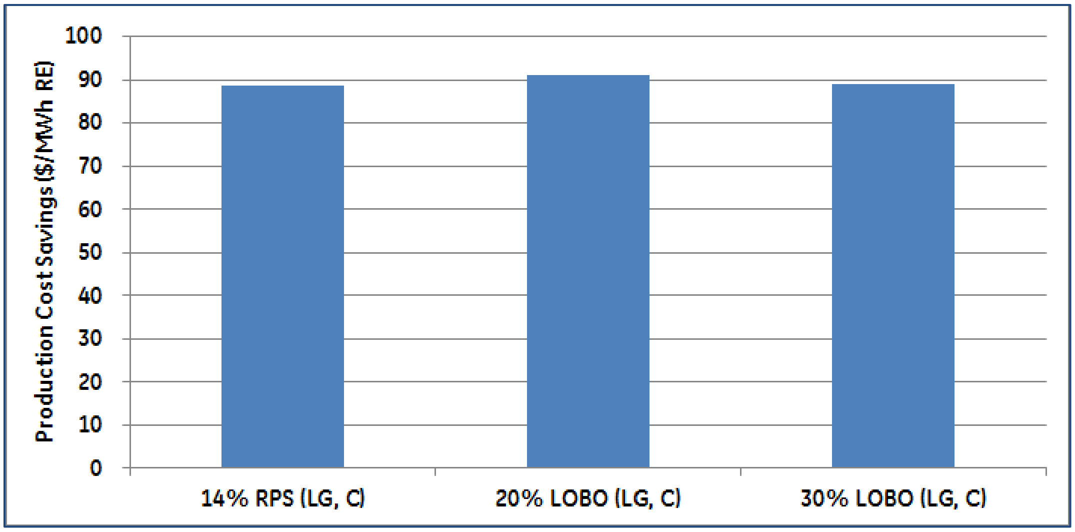

Figure 3-48: Production Cost Savings of (LG, C) Sensitivities over 2% BAU per MWh Renewable Additions

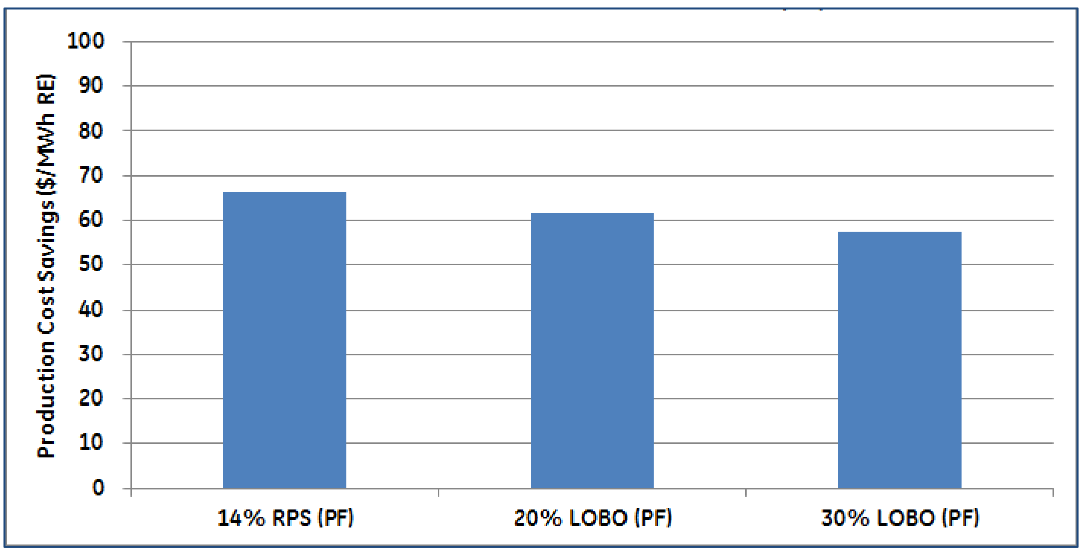

Figure 3-49: Production Cost Savings of (PF) Sensitivities over 2% BAU per MWh Renewable Additions

4 Production Costing Observations

4.1 Operational Performance

Renewable Generation

- Overall, within each penetration level, there is little difference in total delivered renewable energy across the scenarios (i.e., HOBO, LOBO, LODO, and HSBO), although the make-up of the renewable resource (i.e., offshore versus onshore wind, central versus distributed PV) is different for each scenario.
- Curtailed renewable energy is less than 3.5% of the available renewable energy for all cases, with highest curtailments happening in the 20% LOBO and 20% LODO scenarios. However, in absolute terms, the 20% and 30% scenarios (except for HSBO scenarios) show relatively similar levels of curtailment. However, the 30% scenarios also experience higher exports to outside PJM. In the absence of exports, the level of curtailments in 30% scenarios could be higher.
- The 2% and 14% scenarios show significant net imports from PJM neighbors. There is also some net import observed in 30% LOBO scenario. On the other hand, other 30% scenarios - also to a lesser extent - the 20% HSBO scenario, result in net experts, most likely caused by oversupply of generation in these cases.

Coal Based Generation

- Greatest downward impact on the coal generation is in the 20% and 30% LOBO and LODO scenarios. This is caused by higher onshore wind generation in these scenarios, and in some cases due to the proximity of the onshore wind locations to the regions with higher coal generation. Most of the new wind plants are located in the western regions of PJM which also have the greatest share of coal based generation.
- Coal generation, appears to be higher in the HOBO. These results are most likely due to the higher concentration of wind generation in the eastern PJM, and higher concentration of coal generation in the western PJM.
- Coal generation appear to be relatively high in HSBO scenarios, most likely due to need for more baseload unit commitment for off-peak coverage relative to other scenarios (with HSBO having more renewable generation during o-peak and less during off-peak compared to the other scenarios).
- The higher 30% penetration of renewable energy results in more drastic reduction in coal based generation. In both 20% and 30% scenarios, the LOBO (low offshore and best onshore) scenarios results in the largest reduction in coal generation. It can be

surmised that the impact is magnified due to proximity of the best site wind generation to high coal generation regions, particularly in the west of PJM and the Appalachian mountain regions.

- The most dramatic impact on hours of operations and net revenues of Coal generation is under the HOBO cases. Hours of operations directly impacts the net revenues, but it is only one of the drivers. Another factor is the general level of generator prices. Net revenues drop going from 20% to 30% level of renewable penetration. One likely reason for the particular impact of HOBO scenarios is that the offshore wind is located near the PJM Load Centers in the East. The offshore wind it is displacing the expensive generation in the East. Also, since the offshore wind is helping to serve load in the East, the West is exporting less and able to use the inexpensive coal to serve the load in the West. With less SCGT type units running, which are price setting marginal units when running, the overall PJM price levels are expected to be lower under HOBO scenarios, one consequence of which is lowering the net revenues of thermal plants.

Gas Based Generation

- Combined cycle generation are mostly impacted by the 20% and 30% HOBO (high offshore) scenarios, showing the lowest level of generation compared to other 20% and 30% scenarios. The main reason is that there are a greater number of CCGT plants located in the more densely populated eastern regions of PJM, the regions closest to the offshore wind generation. Higher solar generation in HSBO scenarios squeezes out the CCGT and SCGT generation more than the Coal based generation.
- Simple cycle generation is also impacted in most of the scenarios. However, similar to the CCGT plants, the greatest impact on SCGT plants is in the 20% and 30% HOBO scenarios, again mostly due to the proximity of such generation to offshore wind locations.
- The higher 30% penetration of renewable energy results in more drastic reduction in CCGT based generation. In both 20% and 30% scenarios, the HOBO (high offshore and best onshore) scenarios results in the largest reduction in CCGT generation particularly in the eastern regions. The 20% and 30% HSBO scenarios also impact CCGT generation during the on-peak periods.
- In addition to impacts on hours of operations and net revenues, it can be seen that the number of starts, and hence cycling, of CCGTs increases significantly in higher renewable penetration scenarios.
- The HOBO scenarios appeared to increase the operation hours of Coal based units, but have the opposite impact on the CCGT generation.

- The HSBO scenarios increase the number of starts and lower the hours of operation of the CCGT plants – most probably occurring during the on-peak high solar energy periods.
- The HOBO scenarios appear to have impacts on SCGT plants similar to the Coal based and CCGT plants. The HSBO scenarios also lower the hours of operation of SCGT plants – again most likely due to the coincidence of HSBO generation with times of typical high utilization of SCGT plants.
- The 20% and 30% HOBO scenarios appear to impact all thermal units in a similar way in terms of lowering the normalized net revenues of thermal plants, although they impact the hours of operations differently, by increasing them in case of the Coal based units.

4.2 Environmental Emissions

- Criteria pollutants (i.e., NOx and SOx) and greenhouse gasses (i.e., CO2) are reduced in higher renewable penetration scenarios.
- The LOBO scenarios have the greatest impact on lowering of these environmental emissions, in line with the LOBO scenarios having the greatest impact on lowering of coal based generation.

4.3 LMP and Zonal Prices

- Model PJM prices, which are fundamentals-cost-based prices, remain below $100/MWh for majority of the hours during the year.
- The order of price levels from highest to lowest are: BAU, RPS, LODO, LOBO, HSBO, HOBO
- The number of high priced hours drops to a few hundreds in the 20% and 30% scenarios. The HOBO scenarios have the lowest number of hours with prices above $100/MWh.
- Prices jump moving from the most western area in PJM (Commonwealth Edison) and then steadily rise moving across PJM ending at the Southeastern region of PJM (Dominion Virginia Power). On the way there are a few locations where some bumpiness are observed, which are most likely due to any lingering local congestion.
- The HSBO scenario appears to have big impact on price reduction in two areas: Pennsylvania Electric Company area in 20% scenario, and Delmarva Power & Light area in 30% scenario.

- The Delmarva Power & Light area appears to also be impacted in some of the other scenarios, which is likely due to internal transmission transfer capacity limits. Duquesne Light Company area appears to be most impacted by the 30% LODO scenario, which most likely is due to the locally dispersed wind resources.

4.4 Economic Performance

- PJM system production costs drop progressively with higher levels of renewable energy penetration. PJM system production costs in this report refer to the annual total of fuel costs, VOM costs, emission costs (but not modeled in the base scenarios where emission allowance costs were set to zero), and any start-up costs. Production costs do not include any fixed costs or PPA costs of IPP wind and solar energy.
- The 20% and 30% LODO scenarios appear to have the least impact on production costs compared to the other high renewable penetration scenarios, which is most likely due to the relatively dispersed nature of the onshore wind locations which on average are not as good as the best wind locations selected for the other scenarios.
- The HOBO scenarios appear to have the greatest impact on lowering of PJM generator gross revenues in both 20% and 30% scenarios. The HOBO scenarios also have the greatest impact on the PJM prices, and hence help drive the generator gross revenues more than the other scenarios.
- Lower prices also translate to lower PJM costs to serve load. Similarly to the generator gross revenues, it can be seen that the HOBO scenarios also result in lowest PJM Wholesale Customer Energy Cost in comparison to the other scenarios, which is consistent with their impact on lowering the PJM prices.
- Contribution, on a per MWh basis, of the additional renewable energy to the reduction in PJM production costs relative to the 2% BAU scenario, is on the average somewhere from $50 to $70 per MWh of additional wind. This is an “average” production cost savings associated with the impact of the total amount of renewable energy, and not the “marginal” value associated with the last MWh of renewable energy.

4.5 Comparison of Different Load-Wind-Solar Profile Years

- The 2006 profile year, compared to 2004 and 2005 profile years, appears to be a higher wind energy year, for both onshore and offshore wind, which results in slightly lower thermal generation and lower environmental emissions, compared to those other years.

- Except for the generally low penetration 2% BAU scenario, the main difference in unit type performances between different profile years is the change in Average Hours Online of unit types, which for CCGT and Coal units is highest under 2005 profile years and lowest in 2006 profile year. This behavior is consistent with the relative level of wind generation under the examined profile years, with most wind generation under 2006 profile year and least wind generation under 2005 profile year. However, in relative terms, the CCGT and Coal unit Average Hours Online variations are not significant.
- Otherwise, little variation was observed in generation by unit type across different profile years. In summary, using the different profile years does not appear to have a large impact on results. Variations in economic indicators, such as PJM Wholesale Customer Energy Cost, are in low single digit billions of dollars.

4.6 Sensitivity Analysis

Operational Performance Indicators

- The delivered renewable generation remains relatively unchanged under all the sensitivity cases since renewable generation is not subject to dispatch except that it may be curtailed when necessary. As expected, under the Low Load Growth sensitivity, the thermal generation is lower than the base case. Under the Low Load Growth with Low Gas and pure Low Gas sensitivities, coal generation is displaced by CCGT generation.
- The largest impact was seen in the Low Gas with Carbon Price sensitivity. As shown in the previous figures, there is a significant shift from coal generation to CCGT and SCGT generation, which is reflected in the capacity factor values as well. As expected, lower coal generation also results in a significant drop in emissions volume.

Unit Performance Indicators

- All the sensitivities, except for the Perfect Forecast sensitivity, appear to lower the performance indicators of the Coal units, with the Low Gas with Carbon Price sensitivity having the most dramatic impact. CCGT and SCGT performance indicators appear to move in the opposite direction of the Coal units performance indicators. The Perfect Forecast sensitivity seems to have a very small impact on all unit type performances. In all other sensitivities, the Coal generation appears to get displaced by CCGT and SCGT generation. In case of CCGT, the number of starts drops, while the hours online increases.

Economic Indicators

- To gage the economic impact of sensitivities across renewable penetration scenarios, this section compares the results of the two sensitivities that appear to cause the most downward and the most upward change in the economic indicators.
- Table 4-1 presents the changes in the economic indicators compared to the Base Case values across four renewable penetration scenarios under the Low Load Growth with Low Gas sensitivity, which as noted previously, results in the largest decrease in economic indicators relative to the Base Case. The impacts appear to be consistent across all four penetration scenarios. The drop in PJM Wholesale Customer Energy Cost (i.e., Load Cost) ranges from \$12.6B to \$13.9B. Average PJM LMP reduction ranges from \$9.58/MWh to \$11.39/MWh.

Table 4-1: Impact of Low Load Growth with Low Gas Sensitivity across All Renewable Penetration Scenarios

Change from the Base Case	2% BAU (LL, LG)	14% RPS (LL, LG)	20% LOBO (LL, LG)	30% LOBO (LL, LG)
Production Costs (\$M)	-8,826	-6,875	-8,447	-7,918
Relative Change	-36.32%	-30.58%	-41.43%	-56.82%
Generator Revenue (\$M)	-16,197	-14,148	-13,629	-13,859
Relative Change	-30.09%	-27.08%	-29.92%	-32.23%
Cost to Load (\$M)	-13,911	-12,571	-13,800	-13,291
Relative Change	-24.39%	-23.26%	-29.03%	-27.49%
Load Wtd LMP (\$/MWh)	-10.81	-9.58	-11.39	-10.43
Relative Change	-16.45%	-15.39%	-20.81%	-19.76%

- Table 4-2 presents the changes in the economic indicators compared to the Base Case values across four renewable penetration scenarios under the Low Gas with Carbon Price sensitivity, which as noted previously, results in the largest increase in economic indicators relative to the Base Case. The impacts appear to be consistent across all four penetration scenarios, except for the Production Costs of the 20% LOBO scenario, which does not appear to have changed much relative to the Base Case. The rise in PJM Wholesale Customer Energy Cost (i.e., Load Cost) ranges from \$27.4B to \$31.1B. Average PJM LMP reduction ranges from \$28.07/MWh to \$33.52/MWh.

Table 4-2: Impact of Low Gas with Carbon Price Sensitivity on Across All Renewable Penetration Scenarios

Change from the Base Case	2% BAU (LG, C)	14% RPS (LG, C)	20% LOBO (LG, C)	30% LOBO (LG, C)
Production Costs ($M)	5,479	3,708	-228	2,686
Relative Change	14.19%	11.22%	-0.80%	10.95%
Generator Revenue ($M)	23,328	25,083	23,679	23,079
Relative Change	24.99%	27.42%	28.58%	28.87%
Cost to Load ($M)	29,597	31,093	28,952	27,372
Relative Change	29.44%	31.82%	32.06%	30.75%
Load Wtd LMP ($/MWh)	31.91	33.52	31.21	28.07
Relative Change	29.44%	31.82%	32.06%	30.75%

5 Production Costing Appendices

5.1 Appendix A: Scenario Wind and Solar Summaries

Following tables provide a summary of wind and solar energy and capacity in the study scenarios.

Table 5-1: 2% BAU (Reference Case) - Wind Summary

Reference Case	Onshore			Offshore			Total Wind		
States	MW	GWH	CF	MW	GWH	CF	MW	GWH	CF
Illinois	1950	6,879	0.40	0	0	0.00	1950	6,879	0.40
Indiana	1102	3,629	0.38	0	0	0.00	1102	3,629	0.38
Maryland	250	761	0.35	0	0	0.00	250	761	0.35
New Jersey	8	22	0.34	0	0	0.00	8	22	0.34
Pennsylvania	1159	3,476	0.34	0	0	0.00	1159	3,476	0.34
West Virginia	654	2,017	0.35	0	0	0.00	654	2,017	0.35
Total	**5122**	**16,785**	**29.03**	**0**	**0**	**0.00**	**5122**	**16,785**	**29.03**

Table 5-2: 2% BAU (Reference Case) - Solar Summary

Reference Case	Central PV			Distributed PV			Total PV		
States	MW (AC rating)	GWH	CF	MW (AC rating)	GWH	CF	MW (AC rating)	GWH	CF
New Jersey	66	113	0.19	0	0	0.00	66	113	0.19
Ohio	3	4	0.16	0	0	0.00	3	4	0.16
Pennsylvania	3	6	0.22	0	0	0.00	3	6	0.22
Total	**72**	**122**	**0.21**	**0**	**0**	**0.00**	**72**	**122**	**0.21**

Table 5-3: 14% RPS (Base Case) - Wind Summary

14% Base Case	Onshore						Offshore						Total Wind		
	Queue			Additional			Queue			Additional			14% Base Case		
States	MW	GWH	CF	MW	GWH	CF	MW	GWH	CF	MW	GWH	CF	MW	GWH	CF
Delaware							450	1,340	0.34	550	1,653	0.34	1,000	2,993	0.34
Illinois	7,589	26,743	0.40	4,204	15,553	0.42							11,793	42,296	0.41
Indiana	4,051	12,629	0.36	3,054	10,971	0.41							7,105	23,600	0.38
Maryland	380	1,191	0.36										380	1,191	0.36
Michigan	200	633	0.36										200	633	0.36
New Jersey							1,099	3,241	0.34	901	2,757	0.38	2,000	5,999	0.34
North Carolina	374	840	0.26										374	840	0.26
Ohio	3,498	10,488	0.34	1,624	5,233	0.37							5,122	15,721	0.35
Pennsylvania	1,866	5,448	0.33	614	1,988	0.37							2,480	7,436	0.34
Virginia	38	113	0.34							1,000	3,038	0.35	1,038	3,151	0.35
West Virginia	1,237	3,812	0.35	345	1,110	0.37							1,582	4,922	0.36
Total	19,233	61,897	0.37	9,841	34,855	0.40	1,549	4,582	0.34	2,451	7,447	0.35	33,074	108,782	0.38

Table 5-4: 14% RPS (Base Case) - Solar Summary

14% Base Case	Central PV						Distributed PV						Total PV		
	Queue			Additional			Queue			Additional			14% Base Case		
States	MW (AC rating)	GWH	CF	MW (AC rating)	GWH	CF	MW (AC rating)	GWH	CF	MW (AC rating)	GWH	CF	MW (AC rating)	GWH	CF
Delaware	0	0	0.00	150	272	0.21	0	0	0.00	179	271	0.17	329	543	0.19
Illinois	10	16	0.19	376	629	0.19	0	0	0.00	693	949	0.16	1079	1595	0.17
Maryland	40	71	0.20	423	769	0.21	0	0	0.00	545	840	0.18	1008	1680	0.19
North Carolina	5	9	0.21	0	0	0.00	0	0	0.00	6	9	0.18	11	18	0.19
New Jersey	1171	2047	0.20	337	598	0.20	0	0	0.00	1790	2658	0.17	3298	5303	0.18
Ohio	15	22	0.18	272	470	0.20	0	0	0.00	369	492	0.15	655	984	0.17
Pennsylvania	227	399	0.20	48	86	0.21	0	0	0.00	335	486	0.17	609	971	0.18
Virginia	180	317	0.20	0	0	0.00	0	0	0.00	0	0	0.00	180	317	0.20
Washington DC	0	0	0.00	0	0	0.00	0	0	0.00	186	288	0.18	186	288	0.18
Total	**1648**	**2882**	**0.20**	**1606**	**2824**	**0.20**	**0**	**0**	**0.00**	**4102**	**5994**	**0.17**	**7169**	**11412**	**0.18**

Table 5-5: 20% HOBO - Wind Summary

20% High Offshore, best sites	Onshore						Offshore						Total Wind		
	14 % Base Case			Additional			14 % Base Case			Additional			20% High Offshore, best sites		
States	MW	GWH	CF	MW	GWH	CF	MW	GWH	CF	MW	GWH	CF	MW	GWH	CF
Delaware							1,000	3,171	0.36				1,000	3,171	0.36
Illinois	11,840	42,474	0.41										11,840	42,474	0.41
Indiana	5,282	18,200	0.38										5,282	18,200	0.39
Maryland	180	594	0.36							20	65	0.37	200	659	0.38
Michigan	200	633	0.36										200	633	0.36
New Jersey							2,000	6,480	0.37	7,040	23,653	0.38	9,040	30,133	0.38
North Carolina										10,521	35,240	0.38	10,521	35,240	0.38
Ohio	2,291	7,375	0.35										2,291	7,375	0.37
Pennsylvania	712	2,298	0.34										712	2,298	0.37
Virginia							1,000	3,283	0.37	1,000	3,274	0.37	2,000	6,557	0.37
West Virginia	1,127	3,591	0.36										1,127	3,591	0.36
Total	**21,632**	**75,166**	**0.40**	**0**	**0**	**0.00**	**4,000**	**12,934**	**0.37**	**18,581**	**62,231**	**0.38**	**44,213**	**150,331**	**0.39**

Table 5-6: 20% HOBO - Solar Summary

20% Low/High Offshore	Central PV						Distributed PV						Total PV		
	14% Base Case			Additional			14% Base Case			Additional			20% Low/High Offshore		
States	MW (AC rating)	GWH	CF	MW (AC rating)	GWH	CF	MW (AC rating)	GWH	CF	MW (AC rating)	GWH	CF	MW (AC rating)	GWH	CF
Delaware	150	272	0.21	0	0	0.00	179	271	0.17	0	0	0.00	329	543	0.19
Ilinois	386	646	0.19	0	0	0.00	693	949	0.16	698	958	0.16	1,776	2,553	0.16
Indiana	0	0	0.00	0	0	0.00	224	300	0.15	23	29	0.14	248	329	0.15
Kentucky	0	0	0.00	20	37	0.21	0	0	0.00	77	113	0.17	97	149	0.18
Maryland	463	840	0.21	10	18	0.21	545	840	0.18	172	265	0.18	1,190	1,963	0.19
Michigan	0	0	0.00	0	0	0.00	0	0	0.00	48	62	0.15	48	62	0.15
New Jersey	1,509	2,645	0.20	1,086	1,975	0.21	1790	2658	0.17	0	0	0.00	4,384	7,278	0.19
North Carolina	5	9	0.21	0	0	0.00	6	9	0.18	73	112	0.18	84	130	0.18
Ohio	286	492	0.20	0	0	0.00	369	492	0.15	1,573	2,099	0.15	2,228	3,084	0.16
Pennsylvania	0	0	0.00	10	18	0.21	335	486	0.17	1,427	2,071	0.17	1,772	2,575	0.17
Tennessee	275	485	0.20	0	0	0.00	0	0	0.00	20	31	0.18	294	516	0.20
Virginia	180	317	0.20	3,416	6,268	0.21	0	0	0.00	1,293	1,968	0.17	4,889	8,553	0.20
Washington DC	0	0	0.00	0	0	0.00	186	288	0.18	0	0	0.00	185	288	0.18
West Virginia	0	0	0.00	284	523	0.21	0	0	0.00	381	543	0.16	665	1,065	0.18
Total	**3,253**	**5,706**	**0.20**	**4,825**	**8,837**	**0.21**	**4,326**	**6,293**	**0.17**	**5,785**	**8,251**	**0.16**	**18,190**	**29,088**	**0.18**

Table 5-7: 20% LOBO - Wind Summary

20% Low Offshore, best sites	Onshore						Offshore						Total Wind		
	14 % Base Case			Additional			14 % Base Case			Additional			20% Low Offshore, best sites		
States	MW	GWH	CF	MW	GWH	CF	MW	GWH	CF	MW	GWH	CF	MW	GWH	CF
Delaware							1,000	3,171	0.36				1,000	3,171	0.36
Illinois	11,553	41,392	0.41	10,618	38,546	0.41							22,171	79,938	0.41
Indiana	7,105	23,600	0.38										7,105	23,600	0.38
Maryland	380	1,191	0.36										380	1,191	0.36
Michigan	200	633	0.36										200	633	0.36
New Jersey							2,000	6,480	0.37	791	2,798	0.40	2,791	9,278	0.38
North Carolina	374	840	0.26							60	205	0.39	434	1,045	0.28
Ohio	5,122	15,721	0.35										5,122	15,721	0.35
Pennsylvania	2,480	7,436	0.34										2,480	7,436	0.34
Virginia	38	113	0.34				1,000	3,283	0.37				1,038	3,396	0.37
West Virginia	1,582	4,922	0.36										1,582	4,922	0.36
Total	**28,834**	**95,848**	**0.38**	**10,618**	**38,546**	**0.41**	**4,000**	**12,934**	**0.37**	**851**	**3,003**	**0.40**	**44,302**	**150,331**	**0.39**

Table 5-8: 20% LODO - Wind Summary

20% Low Offshore, dispersed	Onshore						Offshore						Total Wind		
	14 % Base Case			Additional			14 % Base Case			Additional			20% Low Offshore, dispersed		
States	MW	GWH	CF	MW	GWH	CF	MW	GWH	CF	MW	GWH	CF	MW	GWH	CF
Delaware							1,000	3,171	0.36				1,000	3,171	0.36
Illinois	11,553	41,392	0.41	2,291	8,353	0.42							13,844	49,745	0.41
Indiana	7,105	23,600	0.38	474	1,648	0.40							7,579	25,248	0.38
Maryland	380	1,191	0.36										380	1,191	0.36
Michigan	200	633	0.36										200	633	0.36
New Jersey							2,000	6,480	0.37	791	2,798	0.40	2,791	9,278	0.38
North Carolina	374	840	0.26							60	205	0.39	434	1,045	0.28
Ohio	5,122	15,721	0.35	4,177	12,998	0.36							9,299	28,719	0.35
Pennsylvania	2,480	7,436	0.34	4,287	12,825	0.34							6,767	20,261	0.34
Virginia	38	113	0.34				1,000	3,283	0.37				1,038	3,396	0.37
West Virginia	1,582	4,922	0.36	879	2,722	0.35							2,461	7,644	0.35
Total	**28,834**	**95,848**	**0.38**	**12,108**	**38,546**	**0.36**	**4,000**	**12,934**	**0.37**	**851**	**3,003**	**0.40**	**45,792**	**150,331**	**0.37**

Table 5-9: 20% HSBO - Wind Summary

20% High Solar, best sites	Onshore						Offshore						Total Wind		
	14 % Base Case			Additional			14 % Base Case			Additional			20% High Solar, best sites		
States	MW	GWH	CF	MW	GWH	CF	MW	GWH	CF	MW	GWH	CF	MW	GWH	CF
Delaware							1,000	3,171	0.36				1,000	3,171	0.36
Illinois	11,553	41,392	0.41	3,394	12,367	0.42							14,947	53,759	0.41
Indiana	7,105	23,600	0.38										7,105	23,600	0.38
Maryland	380	1,191	0.36										380	1,191	0.36
Michigan	200	633	0.36										200	633	0.36
New Jersey							2,000	6,480	0.37	26	95	0.42	2,026	6,575	0.37
North Carolina	374	840	0.26										374	840	0.26
Ohio	5,122	15,721	0.35										5,122	15,721	0.35
Pennsylvania	2,480	7,436	0.34										2,480	7,436	0.34
Virginia	38	113	0.34				1,000	3,283	0.37				1,038	3,396	0.37
West Virginia	1,582	4,922	0.36										1,582	4,922	0.36
Total	**28,834**	**95,848**	**0.38**	**3,394**	**12,367**	**0.42**	**4,000**	**12,934**	**0.37**	**26**	**95**	**0.42**	**36,253**	**121,244**	**0.38**

Table 5-10: 20% HSBO - Solar Summary

20% High Solar	Central PV						Distributed PV						Total PV		
	14% Base Case			Additional			14% Base Case			Additional			20% High Solar		
States	MW (AC rating)	GWH	CF	MW (AC rating)	GWH	CF	MW (AC rating)	GWH	CF	MW (AC rating)	GWH	CF	MW (AC rating)	GWH	CF
Delaware	0	0	0.00	82	146	0.20	179	271	0.17	128	194	0.17	389	612	0.18
llinois	275	485	0.20	0	0	0.00	693	949	0.16	2,078	2,848	0.16	3,046	4,282	0.16
Indiana	180	317	0.20	0	0	0.00	224	300	0.15	340	449	0.15	744	1,066	0.16
Kentucky	0	0	0.00	171	307	0.20	0	0	0.00	176	257	0.17	347	564	0.19
Maryland	150	272	0.21	1,429	2,559	0.20	545	840	0.18	1,090	1,680	0.18	3,215	5,350	0.19
Michigan	0	0	0.00	0	0	0.00	0	0	0.00	109	140	0.15	109	140	0.15
New Jersey	0	0	0.00	2,526	4,556	0.21	1790	2658	0.00	233	347	0.00	4,549	7,561	0.19
North Carolina	5	9	0.21	1	2	0.20	6	9	0.18	173	267	0.18	185	287	0.18
Ohio	286	492	0.20	0	0	0.00	369	492	0.15	4,058	5,416	0.15	4,714	6,400	0.16
Pennsylvania	463	840	0.21	567	1,012	0.20	335	486	0.17	3,682	5,344	0.17	5,046	7,682	0.17
Tennessee	0	0	0.00	77	137	0.20	0	0	0.00	45	70	0.18	122	208	0.19
Virginia	1,509	2,645	0.20	7,670	13,892	0.21	0	0	0.00	2,948	4,487	0.17	12,127	21,024	0.20
Washington DC	386	646	0.19	0	0	0.00	186	288	0.00	37	58	0.00	609	992	0.19
West Virginia	0	0	0.00	422	770	0.21	0	0	0.00	868	1,238	0.16	1,290	2,008	0.18
Total	**3,253**	**5,706**	**0.20**	**12,945**	**23,381**	**0.21**	**4,326**	**6,293**	**0.17**	**15,968**	**22,794**	**0.16**	**36,492**	**58,176**	**0.18**

Table 5-11: 30% HOBO - Wind Summary

30% High Offshore, best sites	Onshore						Offshore						Total Wind		
	14 % Base Case			Additional			14 % Base Case			Additional			30% High Offshore, best sites		
States	**MW**	**GWH**	**CF**	**MW**	**GWH**	**CF**	**MW**	**GWH**	**CF**	**MW**	**GWH**	**CF**	**MW**	**GWH**	**CF**
Delaware							1,000	3,171	0.36				1,000	3,171	0.36
Illinois	11,553	41,392	0.41	4,972	18,103	0.42							16,525	59,495	0.41
Indiana	7,105	23,600	0.38										7,105	23,600	0.38
Maryland	380	1,191	0.36							1,080	3,444	0.36	1,460	4,635	0.36
Michigan	200	633	0.36										200	633	0.36
New Jersey							2,000	6,480	0.37	9,740	32,377	0.38	11,740	38,857	0.38
North Carolina	374	840	0.26							15,669	52,227	0.38	16,042	53,067	0.38
Ohio	5,122	15,721	0.35										5,122	15,721	0.35
Pennsylvania	2,480	7,436	0.34										2,480	7,436	0.34
Virginia	38	113	0.34				1,000	3,283	0.37	4,000	12,966	0.37	5,038	16,362	0.37
West Virginia	1,582	4,922	0.36										1,582	4,922	0.36
Total	**28,834**	**95,848**	**0.38**	**4,972**	**18,103**	**0.00**	**4,000**	**12,934**	**0.37**	**30,489**	**101,014**	**0.38**	**68,294**	**227,899**	**0.38**

Table 5-12: 30% HOBO - Solar Summary

30% Low/High Offshore	Central PV						Distributed PV						Total PV		
	20% Low/High Offshore			Additional			20% Low/High Offshore			Additional			30% Low/High Offshore		
States	MW (AC rating)	GWH	CF	MW (AC rating)	GWH	CF	MW (AC rating)	GWH	CF	MW (AC rating)	GWH	CF	MW (AC rating)	GWH	CF
Delaware	150	272	0.21	20	35	0.20	179	271	0.17	75	114	0.17	424	692	0.19
Ilinois	386	646	0.19	0	0	0.00	1,391	1,908	0.16	902	1,234	0.16	2,679	3,787	0.16
Indiana	0	0	0.00	0	0	0.00	248	329	0.15	219	291	0.15	467	620	0.15
Kentucky	20	37	0.21	100	179	0.21	77	113	0.17	68	100	0.17	265	428	0.18
Maryland	472	858	0.21	1,029	1,846	0.20	717	1,105	0.18	636	979	0.18	2,854	4,788	0.19
Michigan	0	0	0.00	0	0	0.00	48	62	0.15	42	55	0.15	90	116	0.15
New Jersey	2,595	4,620	0.20	1,008	1,812	0.21	1,790	2,658	0.17	0	0	0.00	5,392	9,090	0.19
North Carolina	5	9	0.21	1	2	0.20	79	121	0.18	70	107	0.18	154	239	0.18
Ohio	286	492	0.20	0	0	0.00	1,942	2,592	0.15	1,721	2,297	0.15	3,949	5,380	0.16
Pennsylvania	10	18	0.21	146	261	0.21	1,762	2,557	0.17	1,561	2,266	0.17	3,479	5,102	0.17
Tennessee	275	485	0.20	77	137	0.20	20	31	0.18	18	27	0.18	389	681	0.20
Virginia	3,596	6,585	0.21	2,910	5,231	0.21	1,293	1,968	0.17	1,146	1,744	0.17	8,945	15,528	0.20
Washington DC	0	0	0.00	0	0	0.00	185	288	0.18	0	0	0.00	185	288	0.18
West Virginia	284	523	0.21	108	194	0.21	381	543	0.16	337	481	0.16	1,110	1,741	0.18
Total	**8,079**	**14,544**	**0.21**	**5,397**	**9,696**	**0.21**	**10,111**	**14,545**	**0.16**	**6,796**	**9,695**	**0.16**	**30,383**	**48,480**	**0.18**

Table 5-13: 30% LOBO - Wind Summary

30% Low Offshore, best sites	Onshore						Offshore						Total Wind		
	20% Low Offshore, best sites			Additional			20% Low Offshore, best sites			Additional			20% Low Offshore, best sites		
States	MW	GWH	CF	MW	GWH	CF	MW	GWH	CF	MW	GWH	CF	MW	GWH	CF
Delaware							1,000	3,171	0.36				1,000	3,171	0.36
Illinois	22,171	79,938	0.41	12,370	43,083								34,541	123,021	0.41
Indiana	7,105	23,600	0.38	7,642	26,251								14,748	49,852	0.39
Iowa				301	1,042								301	1,042	0.40
Maryland	380	1,191	0.36										380	1,191	0.36
Michigan	200	633	0.36										200	633	0.36
New Jersey							2,791	9,278	0.38	1,080	3,737		3,871	13,015	0.38
North Carolina	374	840	0.26				60	205	0.39	915	3,114		1,349	4,160	0.35
Ohio	5,122	15,721	0.35										5,122	15,721	0.35
Pennsylvania	2,480	7,436	0.34										2,480	7,436	0.34
Virginia	38	113	0.34	100	340		1,000	3,283	0.37				1,138	3,736	0.37
West Virginia	1,582	4,922	0.36										1,582	4,922	0.36
Total	**39,452**	**134,394**	**0.39**	**20,414**	**70,717**	**0.40**	**4,851**	**15,937**	**0.38**	**1,995**	**6,851**	**0.39**	**66,712**	**227,899**	**0.39**

Table 5-14: 30% LODO - Wind Summary

30% Low Offshore, dispersed	Onshore						Offshore						Total Wind		
	20% Low Offshore, dispersed			Additional			20% Low Offshore, dispersed			Additional			20% Low Offshore, dispersed		
States	MW	GWH	CF	MW	GWH	CF	MW	GWH	CF	MW	GWH	CF	MW	GWH	CF
Delaware							1,000	3,171	0.36				1,000	3,171	0.36
Illinois	13,844	49,745	0.41	7,956	28,850	0.41							21,800	78,595	0.41
Indiana	7,579	25,248	0.38	843	2,985	0.40							8,422	28,233	0.38
Maryland	380	1,191	0.36										380	1,191	0.36
Michigan	200	633	0.36										200	633	0.36
New Jersey							2,791	9,278	0.38	1,080	3,737	0.40	3,871	13,015	0.38
North Carolina	374	840	0.26				60	205	0.39	915	3,114	0.39	1,349	4,160	0.35
Ohio	9,299	28,719	0.35	8,146	23,883	0.33							17,445	52,602	0.34
Pennsylvania	6,767	20,261	0.34	4,092	11,064	0.31							10,859	31,325	0.33
Virginia	38	113	0.34				1,000	3,283	0.37				1,038	3,396	0.37
West Virginia	2,461	7,644	0.35	1,343	3,934	0.33							3,804	11,578	0.35
Total	**40,942**	**134,394**	**0.37**	**22,380**	**70,715**	**0.36**	**4,851**	**15,937**	**0.38**	**1,995**	**6,851**	**0.39**	**70,167**	**227,898**	**0.37**

Table 5-15: 30% HSBO - Wind Summary

30% High Solar, best sites	Onshore						Offshore						Total Wind		
	20% High Solar			Additional			20% High Solar			Additional			30% High Solar, best sites		
States	MW	GWH	CF	MW	GWH	CF	MW	GWH	CF	MW	GWH	CF	MW	GWH	CF
Delaware							1,000	3,171	0.36				1,000	3,171	0.36
Illinois	14,947	53,759	0.41	12,927	46,326	0.41							27,874	100,085	0.41
Indiana	7,105	23,600	0.38	1,972	6,941	0.40							9,077	30,541	0.38
Maryland	380	1,191	0.36										380	1,191	0.36
Michigan	200	633	0.36										200	633	0.36
New Jersey							2,026	6,575	0.37	1,120	3,940	0.40	3,146	10,515	0.38
North Carolina	374	840	0.26							284	969	0.39	658	1,809	0.31
Ohio	5,122	15,721	0.35										5,122	15,721	0.35
Pennsylvania	2,480	7,436	0.34										2,480	7,436	0.34
Virginia	38	113	0.34				1,000	3,283	0.37				1,038	3,396	0.37
West Virginia	1,582	4,922	0.36										1,582	4,922	0.36
Total	**32,228**	**108,215**	**0.38**	**14,899**	**53,267**	**0.41**	**4,026**	**13,029**	**0.37**	**1,404**	**4,909**	**0.40**	**52,557**	**179,420**	**0.39**

Table 5-16: 30% HSBO - Solar Summary

30% High Solar	Central PV						Distributed PV						Total PV		
	20% High Solar			Additional			20% High Solar			Additional			30% High Solar		
States	MW (AC rating)	GWH	CF	MW (AC rating)	GWH	CF	MW (AC rating)	GWH	CF	MW (AC rating)	GWH	CF	MW (AC rating)	GWH	CF
Delaware	82	146	0.20	236	418	0.20	307	465	0.17	204	310	0.17	830	1,340	0.18
Ilinois	275	485	0.20	6	10	0.20	2,771	3,797	0.16	1,847	2,531	0.15	4,899	6,824	0.16
Indiana	180	317	0.20	0	0	0.00	564	749	0.15	376	499	0.15	1,121	1,566	0.16
Kentucky	171	307	0.20	611	1,058	0.20	176	257	0.00	117	171	0.16	1,075	1,793	0.19
Maryland	1,580	2,831	0.20	393	692	0.20	1,636	2,519	0.18	1,090	1,680	0.17	4,699	7,722	0.19
Michigan	0	0	0.00	0	0	0.00	109	140	0.00	73	94	0.14	182	234	0.15
New Jersey	2,526	4,556	0.21	78	138	0.20	2,023	3,005	0.00	1,349	2,003	0.16	5,976	9,702	0.19
North Carolina	6	11	0.21	1,748	3,048	0.20	179	276	0.18	120	184	0.17	2,053	3,519	0.20
Ohio	286	492	0.20	12	21	0.20	4,427	5,908	0.15	2,952	3,939	0.15	7,677	10,360	0.15
Pennsylvania	1,029	1,852	0.21	3,360	5,878	0.20	4,017	5,830	0.17	2,678	3,887	0.16	11,084	17,446	0.18
Tennessee	77	137	0.20	0	0	0.00	45	70	0.00	30	47	0.17	152	254	0.19
Virginia	9,179	16,537	0.21	3,639	6,415	0.20	2,948	4,487	0.00	1,965	2,991	0.17	17,732	30,431	0.20
Washington DC	386	646	0.19				223	346	0.00	149	231	0.17	757	1,222	0.18
West Virginia	422	770	0.21	989	1,713	0.20	868	1,238	0.00	579	825	0.16	2,857	4,545	0.18
Total	**16,198**	**29,088**	**0.20**	**11,072**	**19,392**	**0.20**	**20,294**	**29,088**	**0.16**	**13,529**	**19,392**	**0.16**	**61,093**	**96,959**	**0.18**

5.2 Appendix B: Weekly Generation Pattern

Weekly Performance across Scenarios

Hourly dispatch of generation types for the week with the hour of maximum load is shown in the following figures for each scenario. The intent is to help illustrate how the system performs from hour to hour and day-to-day during operational periods in which the behavior of the wind or wind forecast is challenging.

As can be seen in the following figures, with higher penetration of renewable energy, the thermal resources particularly SCGT and CCGT units are pushed down. The impact on these types of units is most evident in the HSBO scenarios. In some cases, higher penetration of renewable energy results in complete shut-down of all CCGT units during some hours of the weekend.

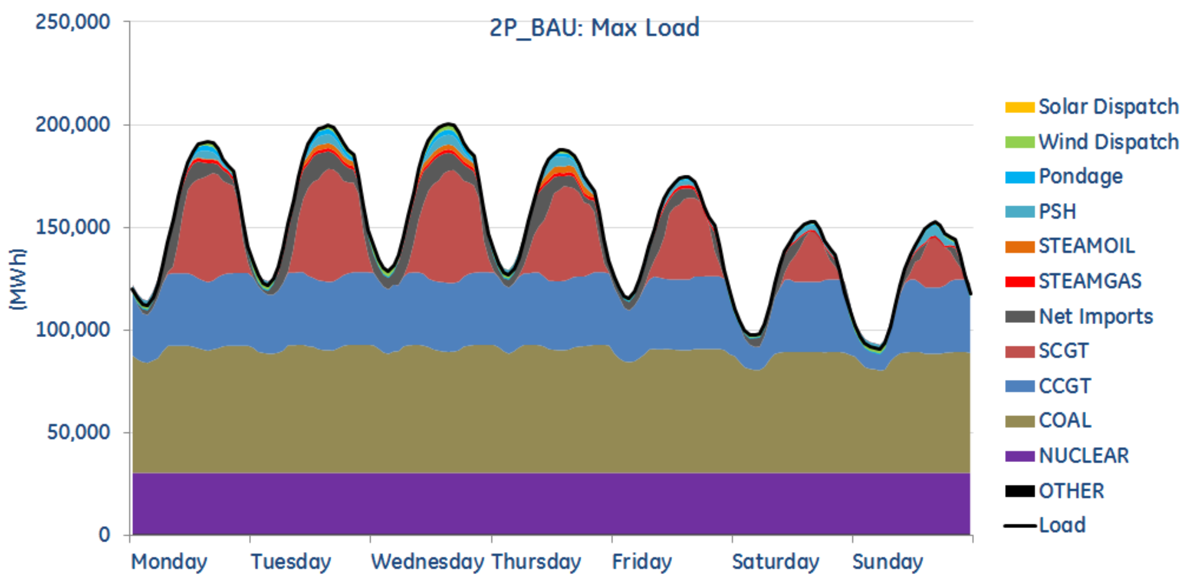

Figure 5-1: Weekly Generation of 2% BAU Scenario during Max Load Week

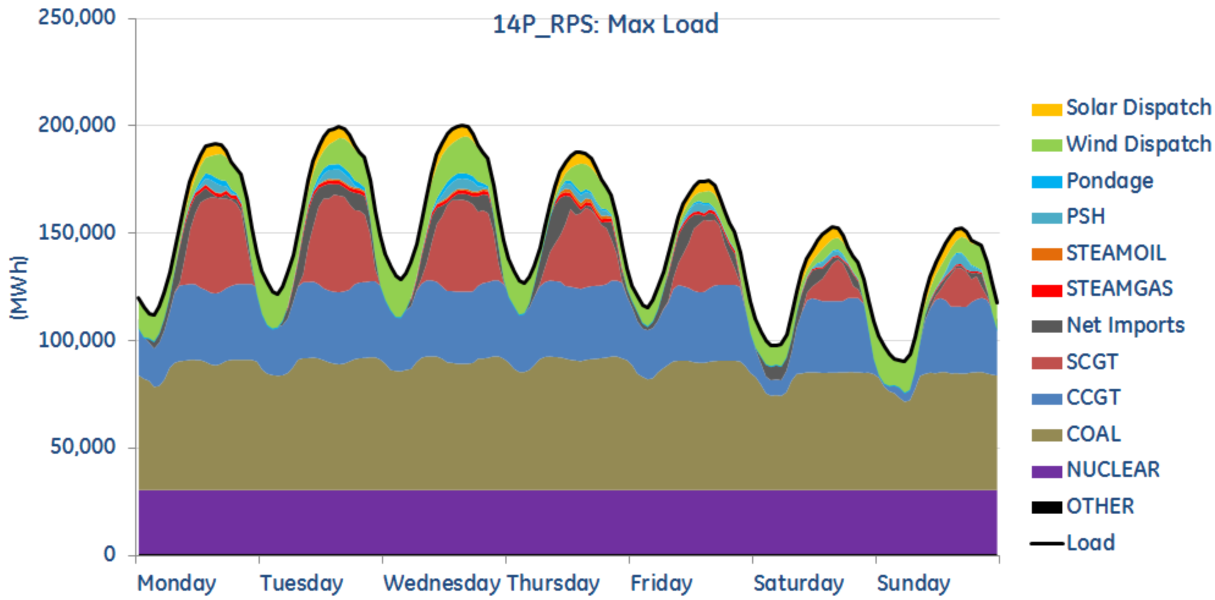

Figure 5-2: Weekly Generation of 14% RPS Scenario during Max Load Week

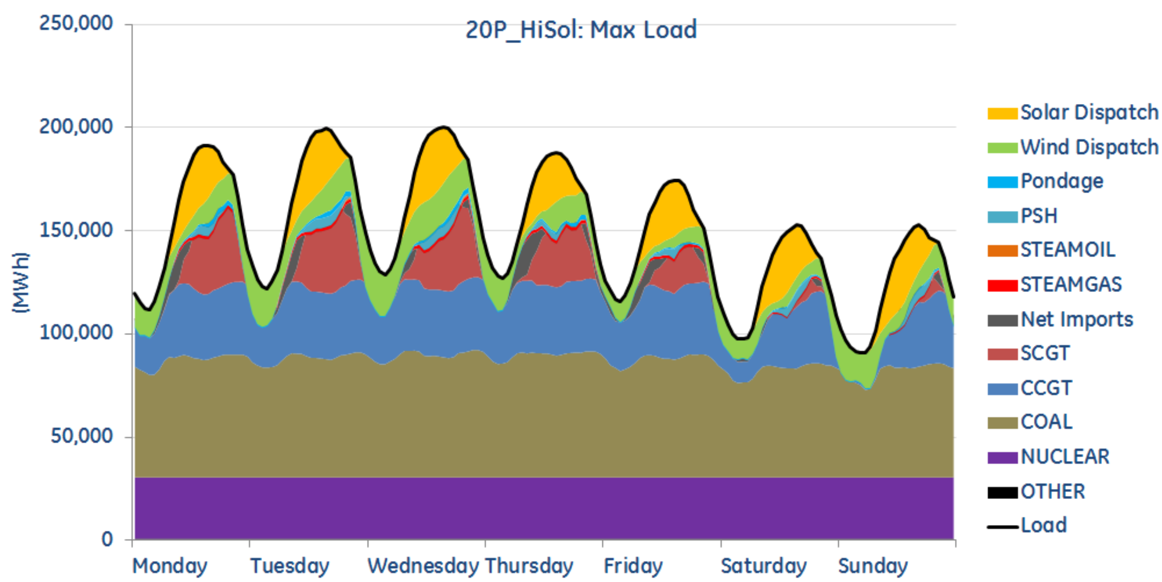

Figure 5-3: Weekly Generation of 20% HSBO Scenario during Max Load Week

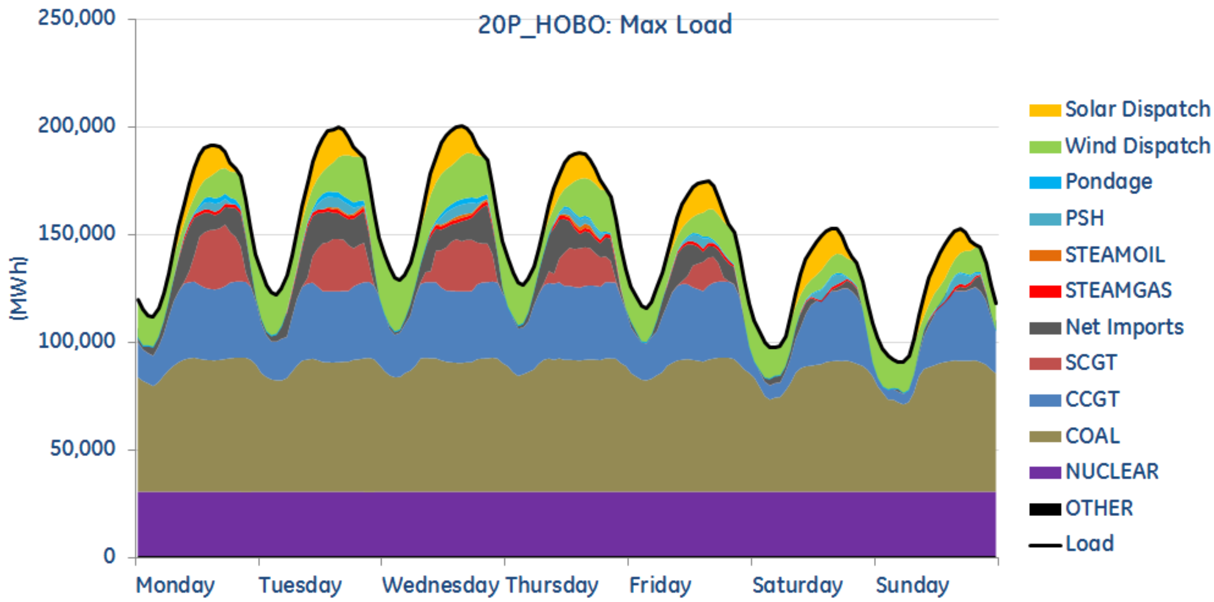

Figure 5-4: Weekly Generation of 20% HOBO Scenario during Max Load Week

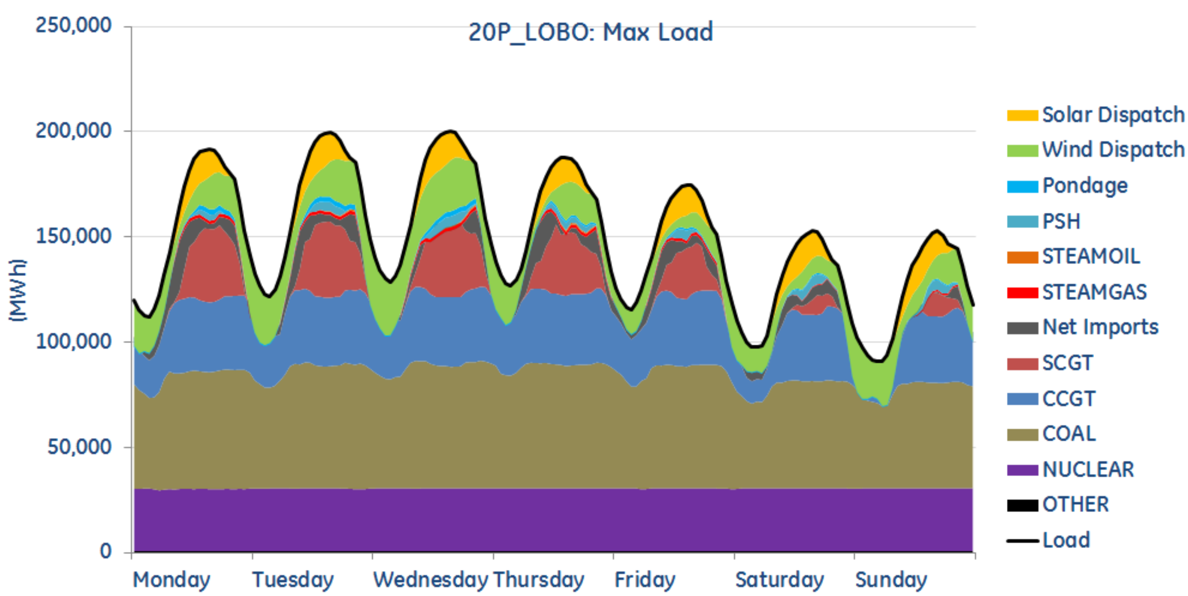

Figure 5-5: Weekly Generation of 20% LOBO Scenario during Max Load Week

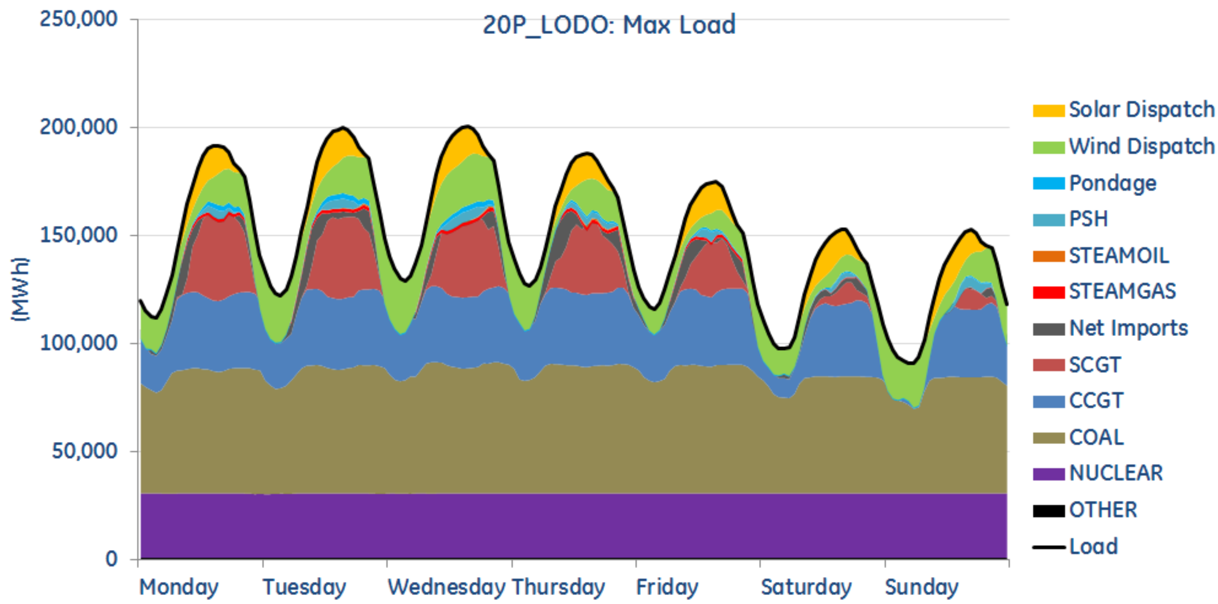

Figure 5-6: Weekly Generation of 20% LODO Scenario during Max Load Week

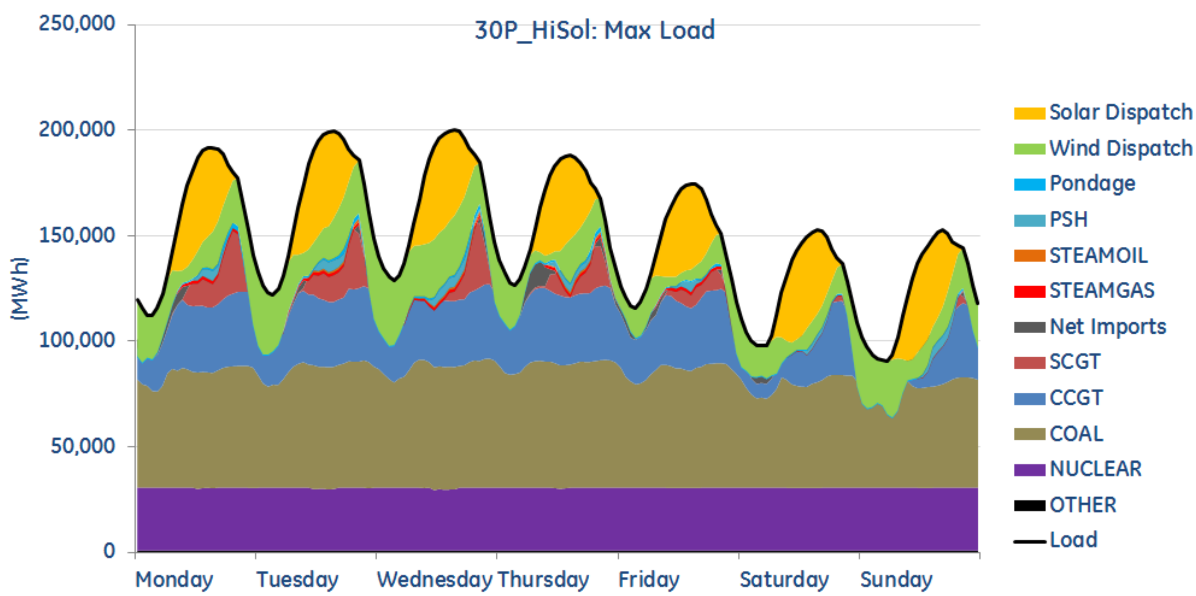

Figure 5-7: Weekly Generation of 30% HSBO Scenario during Max Load Week

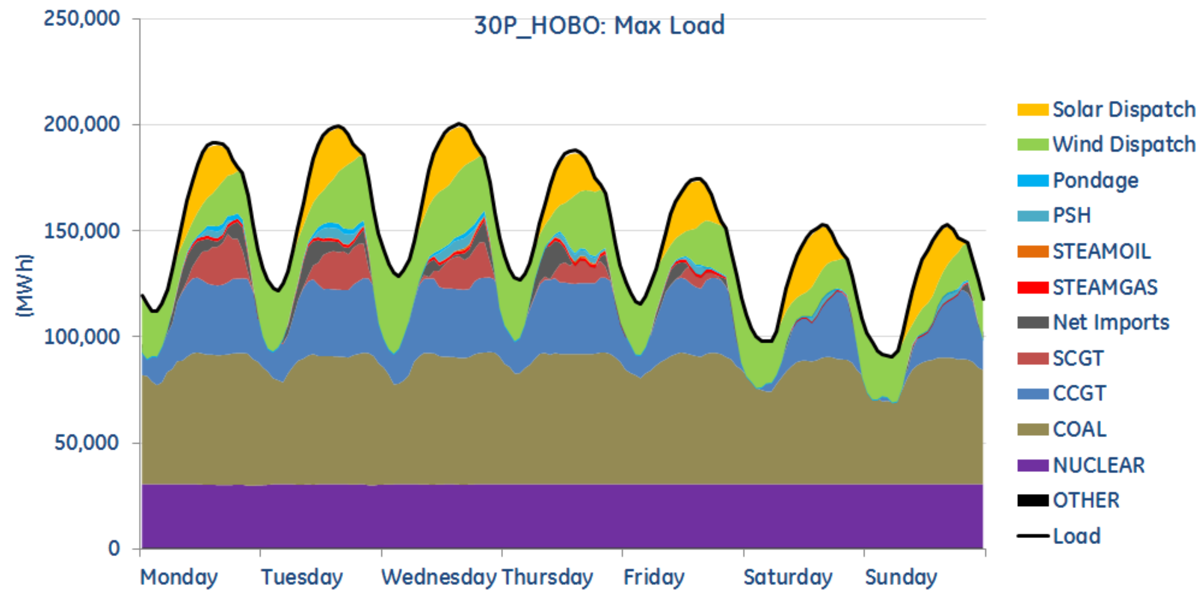

Figure 5-8: Weekly Generation of 30% HOBO Scenario during Max Load Week

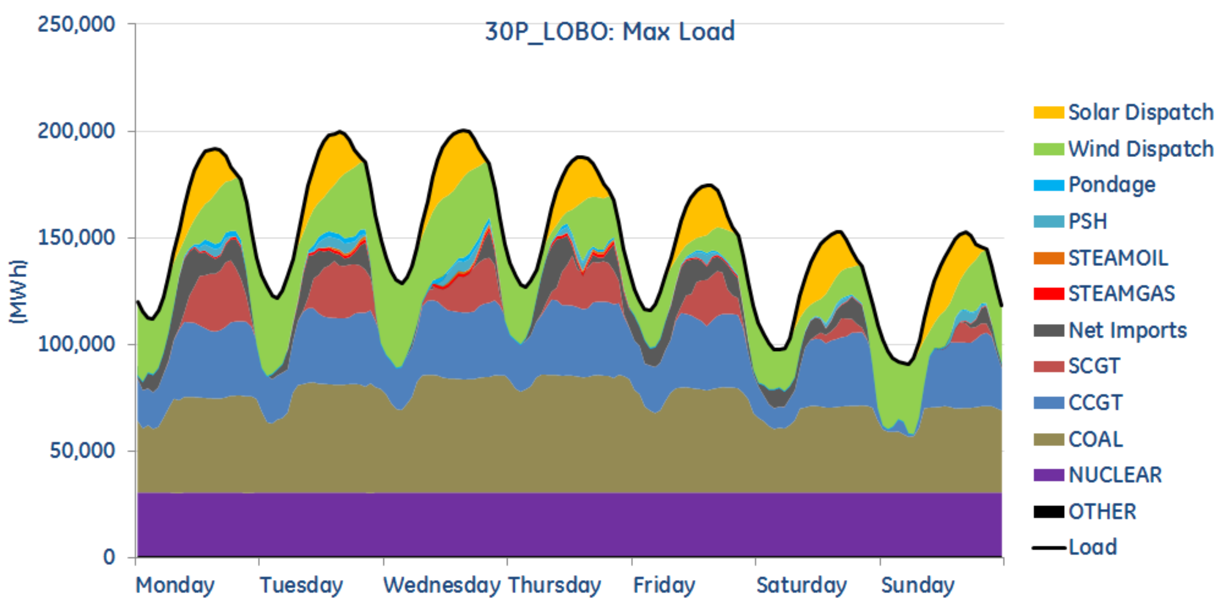

Figure 5-9: Weekly Generation of 30% LOBO Scenario during Max Load Week

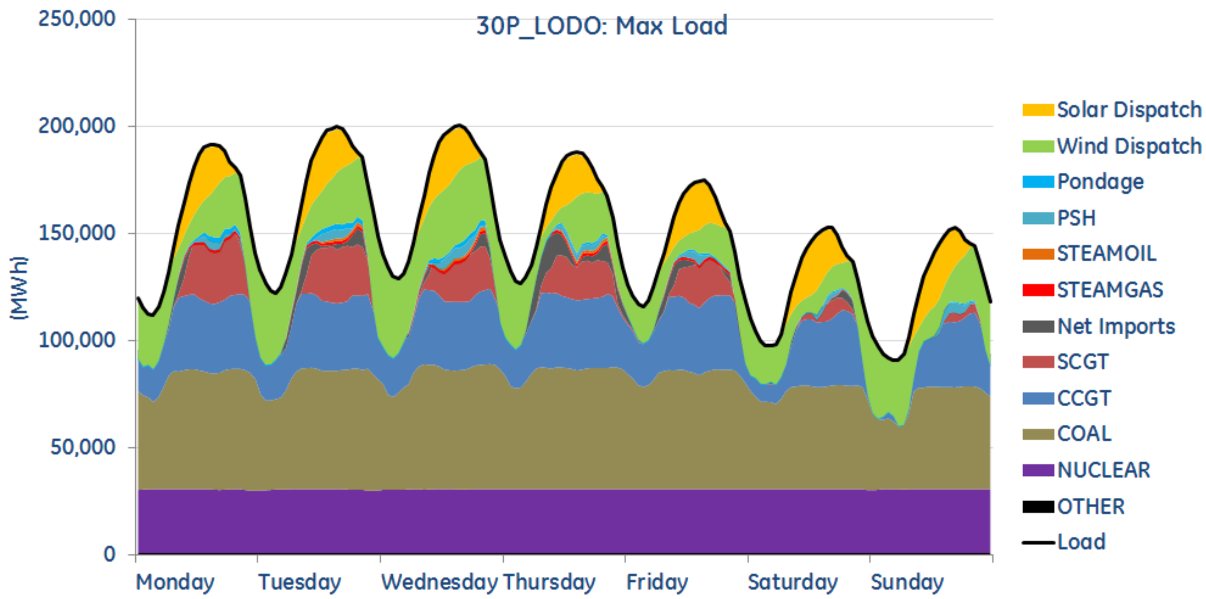

Figure 5-10: Weekly Generation of 30% LODO Scenario during Max Load Week

Weekly Variations within One Scenario

Hourly dispatch of generation types for "interesting weeks" are shown in the following figures for 30% HOBO scenario. This scenario was selected for illustrative purposes. The intent is to help visualize how the system performs from hour to hour and day-to-day during different week types. Selected weeks include the following:

- Week with the hour of Maximum Load
- Week with the hour of Maximum Wind Availability
- Week with the hour of Maximum Solar Availability
- Week with the hour of Maximum Wind Forecast Error

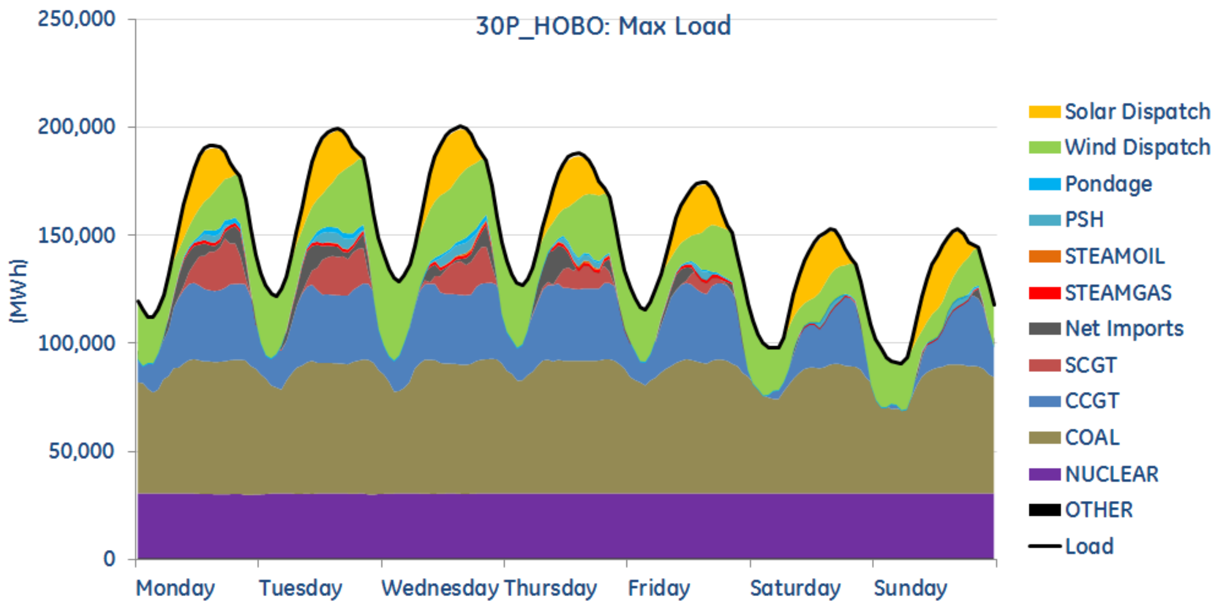

Figure 5-11: Weekly Generation of 30% HOBO Scenario during Max Load Week

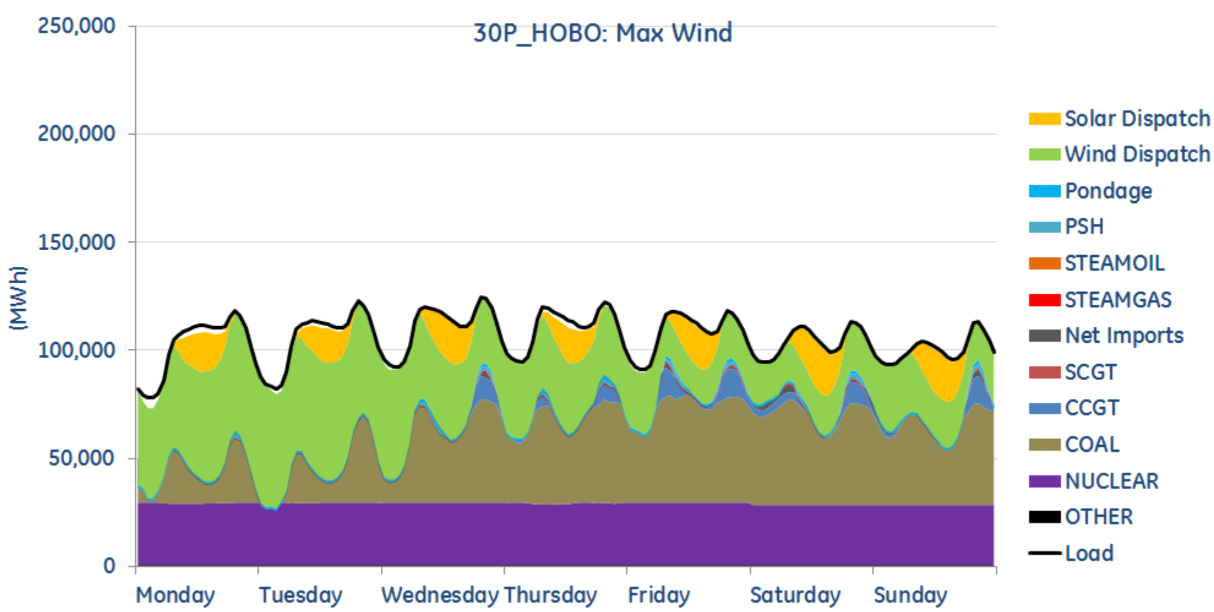

Figure 5-12: Weekly Generation of 30% HOBO Scenario during Max Wind Week

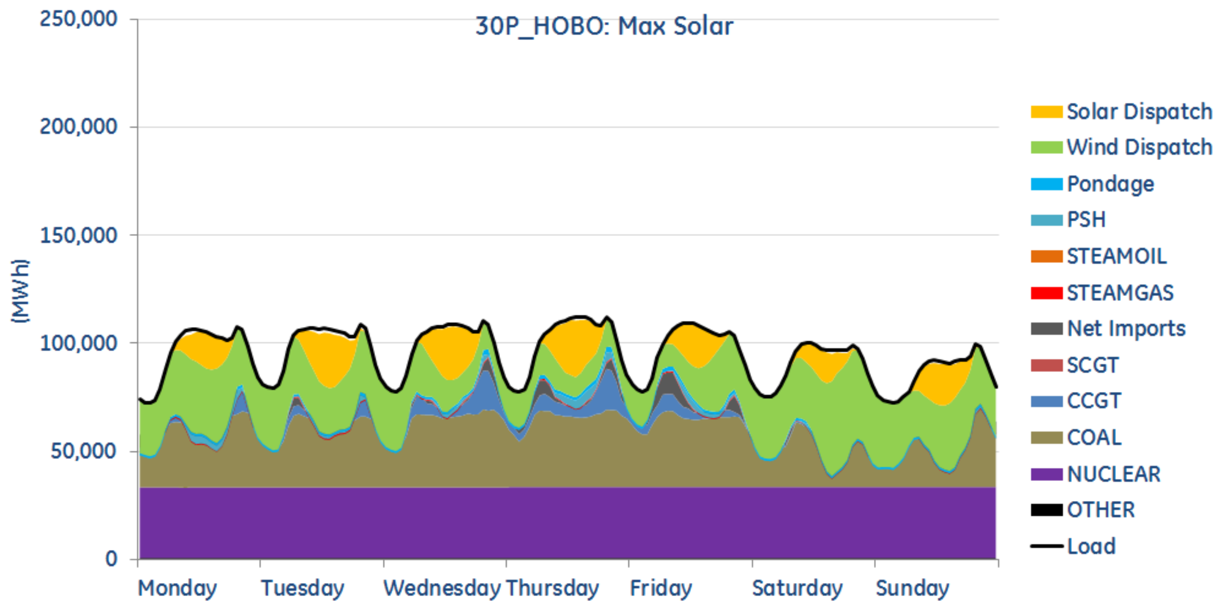

Figure 5-13: Weekly Generation of 30% HOBO Scenario during Max Solar Week

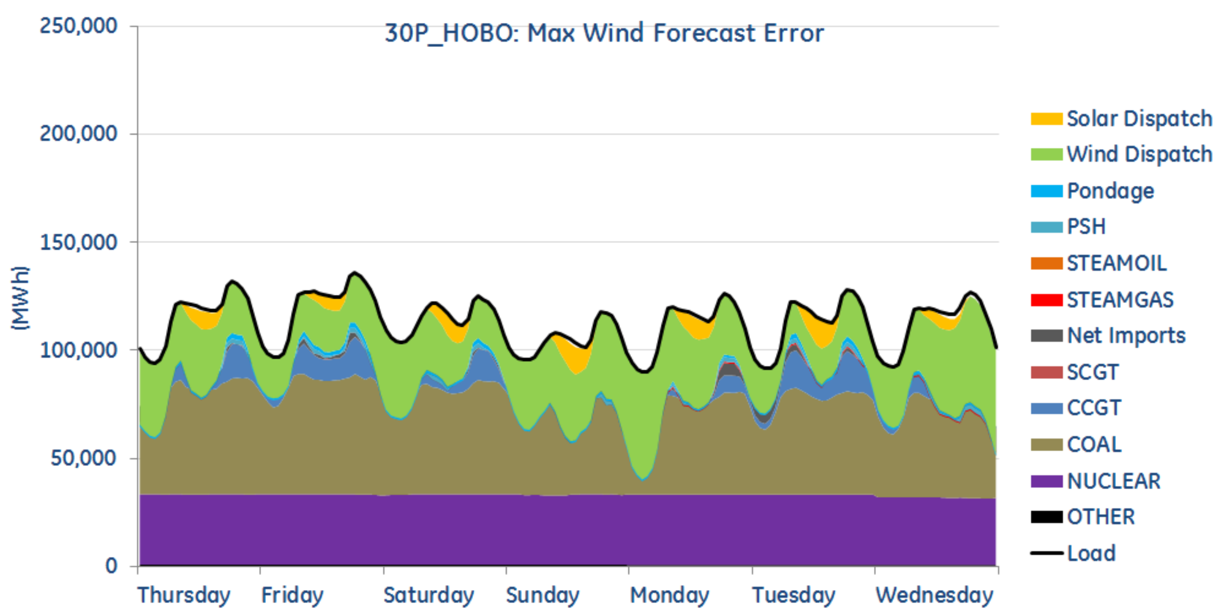

Figure 5-14: Weekly Generation of 30% HOBO Scenario during Max Wind Forecast Error Week

5.3 Appendix C: Transmission Congestion Impact

Top 5 Constraints in Each Scenario

Price variations across PJM are caused by localized congestion, which can cause either local price increases in case of import constrained areas, price decreases in case of export constrained areas. In real life, transmission losses also cause temporal and geographic price variations. However, the modeling in this project does not include transmission losses. Transmission congestion results in dispatch of less economic generation when use of less expensive generation in some part of the transmission grid exacerbate congestion, and more expensive generation on other parts of the grid have to be dispatched in order to meet the system load.

As described elsewhere in this report, the modeling of the PJM in this project is based on iterative overlay of transmission upgrades to reduce PJM congestion until a threshold criteria is met. The joint PJM and GE team agreed on the criteria which is reducing congestion to a level where the difference between the highest generator LMP and the lowest generator LMP is less than or equal to $5/MWh. This criterion was chosen since it was simple to calculate and implement.

To provide a view of the most important transmission congestions in each scenario, Table 5-17 to Table 5-26 provide the top 5 constraints in each scenario that result in the highest congestion costs. The names of the constraints refer to monitored transmission elements in GE MAPS. The underlying definition of each constraint is provided in the section following Table 5-26.

The tables also provide the minimum and maximum ratings of the constraints (in all cases, summer and winter ratings were similar), and also the minimum and maximum hourly flows, amount of energy transferred, the total hours in the year when the constraints are limited - i.e., binding, and the resulting shadow prices on the constraints – where shadow prices are defined as the reduction in total annual system production costs if the constraint in question is relieved by 1 MW (i.e., it its rating is increased by 1 MW). And finally, each table provides the congestion costs associated with each identified constraint.

It should be noted that the sets of top 5 constraints identified in the following tables are based on the final transmission configuration of each scenario after the iterative process of overlay of transmission upgrades over the initial transmission topology.

Table 5-17: Top 5 Congestions of 2% BAU Scenario

Top 5 Constraints 2P_BAU	SUM MIN Ratings (MW)	SUM MAX Ratings (MW)	MIN Flow (MW)	MAX Flow (MW)	AVG Flow (MW)	POS Energy (GWh)	NEG Energy (GWh)	Hours Limited	Total Shadow Prices ($K/MW)	CONG Cost ($M)
05KANAWZ 345DV – 05M FUNK 34	(1,166)	1,166	392	1,169	983	8,612	-	1,346	243	284
AP SOUTH	(5,250)	5,250	2,528	5,300	4,691	41,094	-	1,884	41	213
FlowGate_Powergem - 59	(792)	792	121	1,232	656	5,745	-	2,467	173	147
FlowGate_Powergem - 60	(982)	982	134	1,386	648	5,674	-	477	114	123
WESTERN	(6,550)	6,550	1,070	6,550	5,105	44,716	-	673	18	116
Total Scenario Congestion Cost										1,849

Table 5-18: Top 5 Congestions of 14% RPS Scenario

Top 5 Constraints 14P_RPS	SUM MIN Ratings (MW)	SUM MAX Ratings (MW)	MIN Flow (MW)	MAX Flow (MW)	AVG Flow (MW)	POS Energy (GWh)	NEG Energy (GWh)	Hours Limited	Total Shadow Prices ($K/MW)	CONG Cost ($M)
05KANAWZ 345DV - 05M FUNK 34	(1,166)	1,166	396	1,218	1,071	9,378	-	3,117	634	739
FG-997:CE-AEPNIPS	(99,999)	10,000	(311)	10,009	8,475	74,243	(1)	3,440	60	600
AP SOUTH	(5,250)	5,250	2,426	5,251	4,922	43,115	-	3,179	93	486
FG-6183:QuadCities-Sub91345k	(2,039)	2,039	(3,283)	805	(1,118)	71	(9,864)	1,251	101	221
05DUMONT 765kV - WILTO; 765k	(6,249)	6,249	(6,253)	88	(5,365)	0	(46,998)	1,726	24	148
Total Scenario PJM Congestion Cost										3,980

Table 5-19: Top 5 Congestions of 20% HOBO Scenario

Top 5 Constraints 20P_HOBO	SUM MIN Ratings (MW)	SUM MAX Ratings (MW)	MIN Flow (MW)	MAX Flow (MW)	AVG Flow (MW)	POS Energy (GWh)	NEG Energy (GWh)	Hours Limited	Total Shadow Prices ($K/MW)	CONG Cost ($M)
QUAD3-11 345kV - ROCK CK3 34	(1,591)	1,591	(1,593)	442	(1,267)	11	(11,113)	4,152	446	710
FG-2287:Burnham-Munster345fl	(1,479)	1,479	(1,160)	1,586	1,258	11,073	(51)	5,212	227	335
05DUMONT 765kV - 05DUMONT 34	(2,045)	2,045	(2,045)	932	(1,637)	25	(14,369)	3,069	151	309
FlowGate_Powergem - 130	(1,341)	1,341	321	1,342	1,072	9,394	-	1,967	194	260
05KANAWZ 345EV - 05M FUNK 34	(1,166)	1,166	270	1,200	1,014	8,880	-	2,066	219	256
Total Scenario PJM Congestion Cost										4,313

Table 5-20: Top 5 Congestions of 20% LOBO Scenario

Top 5 Constraints 20P_LOBO	SUM MIN Ratings (MW)	SUM MAX Ratings (MW)	MIN Flow (MW)	MAX Flow (MW)	AVG Flow (MW)	POS Energy (GWh)	NEG Energy (GWh)	Hours Limited	Total Shadow Prices ($K/MW)	CONG Cost ($M)
AP SOUTH	(5,250)	5,250	3,051	7,416	5,021	43,981	-	4,290	142	754
05KANAWZ 345kV - 05M FUNK 34	(1,166)	1,166	499	1,597	1,063	9,313	-	2,405	451	526
CHERR; R 138kV - E ROC;RT 13	(602)	602	242	904	519	4,548	-	2,365	678	434
FlowGate_Powergem - 129	(1,479)	1,479	327	1,935	1,411	12,363	-	5,742	202	298
05BREED 345kV - 16WHEAT 345k	(956)	956	(245)	1,691	718	6,291	(3)	1,643	210	202
Total Scenario PJM Congestion Cost										3,979

Table 5-21: Top 5 Congestions of 20% LODO Scenario

Top 5 Constraints 20P_LODO	SUM MIN Ratings (MW)	SUM MAX Ratings (MW)	MIN Flow (MW)	MAX Flow (MW)	AVG Flow (MW)	POS Energy (GWh)	NEG Energy (GWh)	Hours Limited	Total Shadow Prices ($K/MW)	CONG Cost ($M)
QUAD3-11 345kV - ROCK CK3 34	(1,591)	1,591	(2,420)	703	(1,206)	21	(10,590)	3,750	491	781
AP SOUTH	(5,250)	5,250	2,911	5,373	5,022	43,993	-	4,145	142	748
05KANAWZ 345EV - 05M FUNK 34	(1,166)	1,166	506	1,193	1,077	9,437	-	2,625	464	541
05DUMONT 765kV - WILTO; 765k	(6,249)	6,249	(6,267)	(319)	(5,638)	-	(49,391)	2,822	78	490
FlowGate_Powergem - 130	(1,341)	1,341	345	1,666	1,111	9,729	-	2,580	288	387
Total Scenario PJM Congestion Cost										4,866

Table 5-22: Top 5 Congestions of 20% HSBO Scenario

Top 5 Constraints 20P_HSBO	SUM MIN Ratings (MW)	SUM MAX Ratings (MW)	MIN Flow (MW)	MAX Flow (MW)	AVG Flow (MW)	POS Energy (GWh)	NEG Energy (GWh)	Hours Limited	Total Shadow Prices ($K/MW)	CONG Cost ($M)
AP SOUTH	(5,550)	5,550	2,744	5,551	5,114	44,802	-	3,133	79	439
05DUMONT 765kV - 05DUMONT 34	(2,045)	2,045	(2,049)	656	(1,566)	7	(13,723)	2,724	146	298
05KANAWZ 345BV - 05M FUNK 34	(1,166)	1,166	406	1,167	1,000	8,763	-	1,068	208	243
FG-2287:Burnham-Munster345fl	(1,479)	1,479	(925)	1,592	1,142	10,046	(42)	3,930	152	225
KEYSTONE 230kV - SHELOCTA 23	(911)	911	(911)	911	1	2,134	(2,124)	1,460	137	125
Total Scenario PJM Congestion Cost										3,277

Table 5-23: Top 5 Congestions of 30% HOBO Scenario

Top 5 Constraints 30P_HOBO	SUM MIN Ratings (MW)	SUM MAX Ratings (MW)	MIN Flow (MW)	MAX Flow (MW)	AVG Flow (MW)	POS Energy (GWh)	NEG Energy (GWh)	Hours Limited	Total Shadow Prices ($K/MW)	CONG Cost ($M)
FG-6183:QuadCities-Sub91345k	(2,039)	2,039	(3,983)	721	(1,798)	17	(15,771)	5,365	501	1,100
FG-1714:EVERETS-PA-GRNV230/C	(478)	478	(100)	1,814	799	6,996	(0)	7,544	712	635
FG-2287:Burnham-Munster345fl	(1,479)	1,479	(1,172)	2,050	1,293	11,358	(29)	5,410	307	456
05DUMONT 765kV - 05DUMONT 34	(2,045)	2,045	(2,046)	1,139	(1,712)	22	(15,022)	3,046	158	323
30 LO_OFDIS 688	(1,508)	1,508	(257)	1,515	1,315	11,525	(1)	3,947	151	228
Total Scenario PJM Congestion Cost										5,260

Table 5-24: Top 5 Congestions of 30% LOBO Scenario

Top 5 Constraints 30P_LOBO	SUM MIN Ratings (MW)	SUM MAX Ratings (MW)	MIN Flow (MW)	MAX Flow (MW)	AVG Flow (MW)	POS Energy (GWh)	NEG Energy (GWh)	Hours Limited	Total Shadow Prices ($K/MW)	CONG Cost ($M)
AP SOUTH	(5,250)	5,250	2,706	5,325	4,968	43,519	-	3,919	251	1,316
30 LO_OFBES 2269	(6,300)	6,300	(6,320)	563	(5,012)	1	(43,910)	2,401	81	513
05TWIN B 345AV - 18ARGNTA 34	(1,409)	1,409	(217)	1,420	1,021	8,947	(2)	2,299	201	283
5004/5005	(3,750)	3,750	863	3,781	3,401	29,796	-	3,704	69	257
05KANAWZ 345kV - 05M FUNK 34	(1,166)	1,166	461	1,180	1,020	8,939	-	899	187	219
Total Scenario PJM Congestion Cost										5,160

Table 5-25: Top 5 Congestions of 30% LODO Scenario

Top 5 Constraints 30P_LODO	SUM MIN Ratings (MW)	SUM MAX Ratings (MW)	MIN Flow (MW)	MAX Flow (MW)	AVG Flow (MW)	POS Energy (GWh)	NEG Energy (GWh)	Hours Limited	Total Shadow Prices ($K/MW)	CONG Cost ($M)
05KANAWZ 345CV - 05M FUNK 34	(1,166)	1,166	559	1,209	1,088	9,529	-	3,834	989	1,153
AP SOUTH	(5,250)	5,250	2,847	5,252	4,980	43,628	-	3,471	118	621
E FRA; B 345AV - CRETE;BP 34	(1,399)	1,399	(170)	1,401	1,238	10,843	(1)	4,328	322	450
BELVI; R 138kV - MAREN;RT 13	(428)	428	139	495	389	3,406	-	2,701	541	234
30 LO_OFDIS 1604	(878)	878	(9)	880	706	6,186	(0)	1,797	237	208
Total Scenario PJM Congestion Cost										6307

Table 5-26: Top 5 Congestions of 30% HSBO Scenario

Top 5 Constraints 30P_HSBO	SUM MIN Ratings (MW)	SUM MAX Ratings (MW)	MIN Flow (MW)	MAX Flow (MW)	AVG Flow (MW)	POS Energy (GWh)	NEG Energy (GWh)	Hours Limited	Total Shadow Prices ($K/MW)	CONG Cost ($M)
05KANAWZ 345CV - 05M FUNK 34	(1,166)	1,166	399	1,171	1,044	9,145	-	2,615	499	582
05DUMONT 765kV - WILTO; 765k	(6,249)	6,249	(6,249)	(310)	(4,888)	-	(42,821)	1,385	59	368
AP SOUTH	(5,550)	5,550	2,546	5,550	5,014	43,922	-	2,705	65	362
30P HIS PGEM FG 22	(1,117)	1,117	(1,120)	1,030	(115)	1,976	(2,981)	28	280	313
30 LO_OFBES 318	(956)	956	(958)	265	(699)	5	(6,125)	2,281	322	308
Total Scenario PJM Congestion Cost										5560

Constraint Definitions

FlowGate_Powergem - 59

- MONITOR FLOW ON 314747-314333 1 6BREMO 230.00-6POWHATN 230.00
- FOR THE LOSS OF 314908-314910 1 8ELMONT 500.00-8CUNNING 500.00
- FOR THE LOSS OF 314908-314218 2 8ELMONT 500.00-6ELMONT 230.00

FlowGate_Powergem - 60

- MONITOR FLOW ON 314926-314817 1 8VALLEY 500.00-6VALLEY 230.00
- FOR THE LOSS OF 314907-314926 1 8DOOMS 500.00-8VALLEY 500.00

FlowGate_Powergem - 130

- MONITOR FLOW ON 270630-275207 1 PLANO; 765.00-PLANO;3M 345.00
- FOR THE LOSS OF 270607-270630 1 COLLI; 765.00-PLANO; 765.00

FlowGate_Powergem - 129

- MONITOR FLOW ON 270737-270767 1 ELWOO; R 345.00-GOODI;1R 345.00
- FOR THE LOSS OF 270736-270766 1 ELWOO; B 345.00-GOODI;3B 345.00

30 LO_OFDIS 688

- MONITOR FLOW ON 238654-238569 1 02DAV-BE 345.00-02BEAVER 345.00

30 LO_OFBES 2269

- MONITOR FLOW ON 9996-270630 1 LA SALLE 765.00-PLANO; 765.00

30 LO_OFDIS 1604

- MONITOR FLOW ON 242933-296566 1 05CONVOY 345.00-R60_TAP 345.00
- FOR THE LOSS OF 243214-243231 1 05COLNGW 345.00-05ROB PK 345.00

30P HIS PGEM FG 22

- MONITOR FLOW ON 213866-200013 1 PCHBTM 230.00-PEACHBTM 500.00
- FOR THE LOSS OF 213505-213868 1 COCHRNVL 230.00-PCHBTM2 230.00

30 LO_OFBES 318

- MONITOR FLOW ON 254539-243213 1 16WHEAT 345.00-05BREED 345.00
- FOR THE LOSS OF 243221-249504 1 05EUGENE 345.00-08CAYSUB 345.00

05BREED 345kV - 16WHEAT 345k

- MONITOR FLOW ON 243213-254539 1 05BREED 345.00-16WHEAT 345.00
- FOR THE LOSS OF 243221-249504 1 5EUGENE 345.00-08CAYSUB 345.00
- FOR THE LOSS OF 249504-249505 1 08CAYSUB 345.00-08CAYUGA 345.00

05DUMONT 765kV - 05DUMONT 34

- MONITOR FLOW ON 243206-243219 1 05DUMONT 765.00-05DUMONT 345.00

- FOR THE LOSS OF 243206-270644 1 05DUMONT 765.00-WILTO; 765.00

05DUMONT 765kV - WILTO; 765k

- MONITOR FLOW ON 243206-270644 1 05DUMONT 765.00-WILTO; 765.00

05KANAWZ 345BV - 05M FUNK 34

- MONITOR FLOW ON 242526-242527 1 05KANAWZ 345.00-05M FUNK 345.00
- FOR THE LOSS OF 314917-293013 1 8MT STM 500.00-U2-068 500.00
- FOR THE LOSS OF 314817-314926 1 6VALLEY 230.00-8VALLEY 500.00

05KANAWZ 345CV - 05M FUNK 34

- MONITOR FLOW ON 242526-242527 1 05KANAWZ 345.00-05M FUNK 345.00
- FOR THE LOSS OF 242511-242510 1 05BROADF 765.00-05BAKER 765.00

05KANAWZ 345DV - 05M FUNK 34

- MONITOR FLOW ON 242526-242527 1 05KANAWZ 345.00-05M FUNK 345.00
- FOR THE LOSS OF 242513-242517 1 05CULLOD 765.00-05WYOMIN 765.00

05KANAWZ 345EV - 05M FUNK 34

- MONITOR FLOW ON 242526-242527 1 05KANAWZ 345.00-05M FUNK 345.00
- FOR THE LOSS OF 242511-242514 1 05BROADF 765.00-05J.FERR 765.00
- FOR THE LOSS OF 242566-242567 B 05BROADF 138.00-05BROADX 138.00

05KANAWZ 345kV - 05M FUNK 34

- MONITOR FLOW ON 242526-242527 1 05KANAWZ 345.00-05M FUNK 345.00
- FOR THE LOSS OF 314917-235112 1 8MT STM 500.00-01PRNTY 500.00

05TWIN B 345AV - 18ARGNTA 34

- MONITOR FLOW ON 243234-256000 1 05TWIN B 345.00-18ARGNTA 345.00
- FOR THE LOSS OF 243212-243215 1 05BENTON 345.00-05COOK 345.00

5004/5005

- MONITOR FLOW ON 200011-200071 1 KEYSTONE 500.00-JACKMTN1 500.00

- MONITOR FLOW ON 200005-200072 1 CONEM-GH 500.00-JACKMTN2 500.00

AP SOUTH

- MONITOR FLOW ON 292556-235105 1 T157_TAP 500.00-01DOUBS 500.00
- MONITOR FLOW ON 235837-235110 1 01GRNGAP 500.00-01MDWBRK 500.00
- MONITOR FLOW ON 314917-293013 1 8MT STM 500.00-U2-068 500.00

BELVI; R 138kV - MAREN;RT 13

- MONITOR FLOW ON 271083-271975 1 BELVI; R 138.00-MAREN;RT 138.00
- FOR THE LOSS OF 270695-270883 1 CHERR; R 345.00-SILVE; R 345.00

CHERR; R 138kV - E ROC;RT 13

- MONITOR FLOW ON 271193-271387 1 CHERR; R 138.00-E ROC;RT 138.00
- FOR THE LOSS OF 270695-270883 1 CHERR; R 345.00-SILVE; R 345.00

E FRA; B 345AV - CRETE;BP 34

- MONITOR FLOW ON 270728-274750 1 E FRA; B 345.00-CRETE;BP 345.00
- FOR THE LOSS OF 270677-255109 1 BURNH;0R 345.00-17MUNSTR 345.00

FG-1714:EVERETS-PA-GRNV230/C

- MONITOR FLOW ON 314574-304451 1 6EVERETS 230.00-6PA-GRNV 230.00
- FOR THE LOSS OF 304183-304998 1 8WAKE 500.00-8DBGEN 500.00

FG-2287:Burnham-Munster345fl

- MONITOR FLOW ON 270677-255109 1 BURNH;0R 345.00-17MUNSTR 345.00
- FOR THE LOSS OF 243206-270644 1 05DUMONT 765.00-WILTO; 765.00
- FOR THE LOSS OF 272503-255190 1` SLINE; R 138.00-17WOLFLK 138.00

FG-6183:QuadCities-Sub91345k

- MONITOR FLOW ON 270866-636610 1 QUAD 6-7 345.00-SUB 91 3 345.00
- FOR THE LOSS OF 636600-636605 1 SB 39 3 345.00-MECCORD3 345.00
- FOR THE LOSS OF 636600-636601 1 SB 39 3 345.00-SB 39 5 161.00

FG-997:CE-AEPNIPS

- MONITOR FLOW ON 270674-255111 1 BURNH; B 345.00-17SHEFLD 345.00
- MONITOR FLOW ON 270677-255109 1 BURNH;0R 345.00-17MUNSTR 345.00
- MONITOR FLOW ON 274750-255112 1 CRETE;BP 345.00-17STJOHN 345.00
- MONITOR FLOW ON 272502-255172 1 SLINE; B 138.00-17ROXANA 138.00
- MONITOR FLOW ON 270888-255111 1 SLINE; B 345.00-17SHEFLD 345.00
- MONITOR FLOW ON 272503-255190 1 SLINE; R 138.00-17WOLFLK 138.00
- MONITOR FLOW ON 274804-243229 1 UPNOR;RP 345.00-05OLIVE 345.00
- MONITOR FLOW ON 270644-243206 1 WILTO; 765.00-05DUMONT 765.00

KEYSTONE 230kV - SHELOCTA 23

- MONITOR FLOW ON 200810-200795 1 KEYSTONE 230.00-SHELOCTA 230.00
- FOR THE LOSS OF 238547-239036 1 02AT 345.00-02PERRY 345.00
- FOR THE LOSS OF 200599-238547 1 ERIE W 345.00-02AT 345.00
- FOR THE LOSS OF 200599-200632 1 ERIE W 345.00-ERIE WST 115.00

QUAD3-11 345kV - ROCK CK3 34

- 270864-631141 1 QUAD3-11 345.00-ROCK CK3 345.00

WESTERN

- MONITOR FLOW ON 235105-200003 1 01DOUBS 500.00-BRIGHTON 500.00
- MONITOR FLOW ON 200011-200071 1 KEYSTONE 500.00-JACKMTN1 500.00
- MONITOR FLOW ON 200005-200072 1 CONEM-GH 500.00-JACKMTN2 500.00
- MONITOR FLOW ON 200005-200026 1 CONEM-GH 500.00-HUNTERTN 500.00

5.4 Appendix D: GE MAPS Model Description

Application of GE MAPS to the PJM Study

Production cost modeling of the PJM system was performed with the GE's Multi Area Production Simulation (GE MAPS) software program. This commercially available modeling tool has a long history of governmental, regulatory, independent system operator and investor-owned utility applications. The production cost model provides the unit-by-unit production output (MW) on an hourly basis for an entire year of production (GWh of electricity production by each unit). The results also provide information about the variable cost of electricity production, emissions, fuel consumption, etc.

The overall simulation algorithm is based on standard least marginal cost operating practice. That is, generating units that can supply power at lower marginal cost of production are committed and dispatched before units with higher marginal cost of generation. Commitment and dispatch are constrained by physical limitations of the system, such as transmission thermal limits, minimum spinning reserve, as well as the physical limitations and characteristics of the power plants.

The primary source of model uncertainty and error for production cost simulations, based on the model, consist of:

- Some of the constraints in the model may be somewhat simpler than the precise situation dependent rules used by PJM.
- Marginal production-cost models consider heat rate and a variable O&M cost. However, the models do not include an explicit heat-rate penalty or an O&M penalty for increased maneuvering that may be a result of incremental system variability due to as-available renewable resources (in future scenarios).
- The production cost model requires input assumptions like forecasted fuel price, forecasted system load, estimated unit heat rates, maintenance and forced outage rates, etc. Variations from these assumptions could significantly alter the results of the study.

Simulation results provide insight into hour-to-hour operations, and how the commitment and dispatch may change subject to various changes, including equipment or operating practices. Since the production cost model depends on fuel price as an input, relative costs and change in costs between alternative scenarios tend to produce better and more useful information than absolute costs. The results from the model approximate system dispatch and production, but do not necessarily identically match system behavior. The results do not necessarily reproduce accurate production costs on a unit-by-unit basis and do not accurately reproduce every aspect of system operation. However, the model reasonably quantifies the incremental changes in marginal cost, emissions, fossil fuel consumption, and other operations metrics due to changes, such as higher levels of wind power.

Unique Features of GE MAPS

GE MAPS is a highly detailed model that calculates hour-by-hour production costs while recognizing the constraints on the dispatch of generation imposed by the transmission system. When the program was initially developed over twenty years ago, its primary use was as a generation and transmission planning tool to evaluate the impacts of transmission system constraints on the system production cost. In the current deregulated utility environment, the acronym GE MAPS may more also stand for Market Assessment & Portfolio Strategies because of the model's usefulness in studying issues such as market power and the valuation of generating assets operating in a competitive environment.

The unique modeling capabilities of GE MAPS use a detailed electrical model of the entire transmission network, along with generation shift factors determined from a solved ac load flow, to calculate the real power flows for each generation dispatch. This enables the user to capture the economic penalties of re-dispatching the generation to satisfy transmission line flow limits and security constraints.

Separate dispatches of the interconnected system and the individual companies' own load and generation are performed to determine the economic interchange of energy between companies. Several methods of cost reconstruction are available to compute the individual company costs in the total system environment. The chronological nature of the hourly loads is modeled for all hours in the year. In the electrical representation, the loads are modeled by individual bus.

In addition to the traditional production costing results, MAPS can provide information on the hourly spot prices at individual buses and on the flows on selected transmission lines for all hours in the year, as well as identifying the companies responsible for the flows on a given line.

Because of its detailed representation of the transmission system, GE MAPS can be used to study issues that often cannot be adequately modeled with conventional production costing software. These issues include:

Market Structures – GE MAPS is being used extensively to model emerging market structures in different regions of the United States. It has been used to model the New York, New England, PJM and California ISOs for market power studies, stranded cost estimates, and project evaluations.

Transmission Access – GE MAPS calculates the hour spot price ($/MWh) at each bus modeled, thereby defining a key component of the total avoided cost that is used in formulating contracts for transmission access by non-utility generators and independent power producers.

Loop Flow or Uncompensated Wheeling – The detailed transmission modeling and cost reconstruction algorithms in MAPS combine to identify the companies contributing to the flow on a given transmission line and to define the production cost impact of that loading.

Transmission Bottlenecks – GE MAPS can determine which transmission lines and interfaces in the system are bottlenecks and how many hours during the year these lines are limiting. Next, the program can be used to assess, from an economic point of view, the feasibility of various methods, such as transmission line upgrades or the installation of phase-angle regulators for alleviating bottlenecks.

Evaluation of New Generation, Transmission, or Demand-Side Facilities – GE MAPS can evaluate which of the available alternatives under consideration has the most favorable impact on system operation in terms of production costs and transmission system loading.

Power Pooling – The cost reconstruction algorithms in GE MAPS allow individual company performance to be evaluated with and without pooling arrangements, so that the benefits associated with pool operations can be defined.

Modeling Capabilities of GE MAPS

GE MAPS has evolved to study the management of a power system's generation and transmission resources to minimize generation production costs while considering transmission security. The modeling capabilities of MAPS are summarized below:

Time Frame – One year to several years with ability to skip years.

- Company Models – Up to 175 companies.
- Load Models – Up to 175 load forecasts. The load shapes can include all 365 days or automatically compress to a typical week (seven different day shapes) per month. The day shapes can be further compressed from 24 to 12 hours, with bi-hourly loads.
- Generation – Up to 7,500 thermal units, 500 pondage plants, 300 run-of-river plants, 50 energy-storage plants, 15 external contracts, 300 units jointly owned, and 2,000 fuel types. Thermal units have full and partial outages, daily planned maintenance, fixed and variable operating and maintenance costs, minimum down-time, must-run capability, and up to four fuels at a unit.
- Network Model –Includes 50,000 buses, 100,000 lines, 145 phase-angle regulators, and 100 multi-terminal High-Voltage Direct Current lines. Line or interface transmission limits may be set using operating nomograms as well as thermal,

voltage and stability limits. Line or interface limits may be varied by generation availability.

- Losses - Transmission losses may vary as generation and loads vary, approximating the ac power flow behavior, or held constant, which is the usual production simulation assumption. The incremental loss factors are recalculated each hour to reflect their dependence on the generation dispatch.
- Marginal Costs – Marginal costs for an increment such as 100 MW can be identified by running two cases, one 100 MW higher, with or without the same commitment and pumped-storage hydro schedule. A separate routine prepares the cost difference summaries. Hourly bus spot prices are also computed.
- Operating Reserves – Modeled on an area, company, pool and system basis.
- Secure Dispatch – Up to 5,000 lines and interfaces and nomograms may be monitored. Each study hour considers the effect of hundreds of different network outages.
- Report Analyzer – MAPS allows the simulation results to be analyzed through a powerful report analyzer program, which incorporates full screen displays, customizable output reports, graphical displays and databases. The built-in programming language allows the user to rapidly create custom reports.
- Accounting – Separate commitment and dispatches are done for the system and for the company own-load assumptions, allowing cost reconstruction and cost splitting on a licensee-agreed basis. External economy contracts are studied separately after the base dispatch each hour.
- Bottom Line – Annual fuel plus O&M costs for each company, fuel consumption, and generator capacity factors.

5.5 Appendix E: GE MARS Model Description

The Multi-Area Reliability Simulation software program (GE MARS) enables the electric utility planner to quickly and accurately assess the reliability of a generation system comprised of any number of interconnected areas.

Mars Modeling Technique

A sequential Monte Carlo simulation forms the basis for MARS. The Monte Carlo method provides a fast, versatile, and easily-expandable program that can be used to fully model many different types of generation and demand-side options.

In the sequential Monte Carlo simulation, chronological system histories are developed by combining randomly-generated operating histories of the generating units with the inter-area transfer limits and the hourly chronological loads. Consequently, the system can be modeled in great detail with accurate recognition of random events, such as equipment failures, as well as deterministic rules and policies which govern system operation, without the simplifying or idealizing assumptions often required in analytical methods.

Reliability Indices Available From Mars

The following reliability indices are available on both an isolated (zero ties between areas) and interconnected (using the input tie ratings between areas) basis:

- Daily LOLE (days/year)
- Hourly LOLE (hours/year)
- LOEE (MWh/year)
- Frequency of outage (outages/year)
- Duration of outage (hours/outage)
- Need for initiating emergency operating procedures (days/year)

The use of Monte Carlo simulation allows for the calculation of probability distributions, in addition to expected values, for all of the reliability indices. These values can be calculated both with and without load forecast uncertainty.

Description of Program Models

Loads: The loads in MARS are modeled on an hourly, chronological basis for each area being studied. The program has the option to modify the input hourly loads through time to meet specified annual or monthly peaks and energies. Uncertainty on the annual peak load forecast can also be modeled, and can vary by area on a monthly basis.

MARS has the capability to model the following different types of resources:

- Thermal
- Energy-limited
- Cogeneration
- Energy-storage
- Demand-side management

An energy-limited unit can be modeled stochastically as a thermal unit with an energy probability distribution (Type 1 energy-limited unit), or deterministically as a load modifier (Type 2 energy-limited unit). Cogeneration units are modeled as thermal units with an associated hourly load demand. Energy-storage and demand-side management are modeled as load modifiers.

For each unit modeled, the user specifies the installation and retirement dates and planned maintenance requirements. Other data such as maximum rating, available capacity states, state transition rates, and net modification of the hourly loads are input depending on the unit type.

The planned outages for all types of units in MARS can be specified by the user or automatically scheduled by the program on a weekly basis. The program schedules planned maintenance to levelize reserves on an area, pool, or system basis. MARS also has the option of reading a maintenance schedule developed by a previous run and modifying it as specified by the user through any of the maintenance input data. This schedule can then be saved for use by subsequent runs.

Thermal Units: In addition to the data described previously, thermal units (including Type 1 energy-limited units and cogeneration) require data describing the available capacity states in which the unit can operate. This is input by specifying the maximum rating of each unit and the rating of each capacity state as a per-unit of the unit's maximum rating. A maximum of eleven capacity states are allowed for each unit, representing decreasing amounts of available capacity as a result of the outages of various unit components.

Because MARS is based on a sequential Monte Carlo simulation, it uses state transition rates, rather than state probabilities, to describe the random forced outages of the thermal units. State probabilities give the probability of a unit being in a given capacity state at any particular time, and can be used if you assume that the unit's capacity state for a given hour is independent of its state at any other hour. Sequential Monte Carlo simulation recognizes the fact that a unit's capacity state in a given hour is dependent on its state in previous hours and influences its state in future hours. It thus requires the additional information that is contained in the transition rate data.

For each unit, a transition rate matrix is input that shows the transition rates to go from each capacity state to each other capacity state. The transition rate from state A to state B is defined as the number of transitions from A to B per unit of time in state A:

$$\textit{TR (A to B)} = \frac{\textit{Number of Transitions from A to B}}{\textit{Total Time in State A}}$$

If detailed transition rate data for the units is not available, MARS can approximate the transitions rates from the partial forced outage rates and an assumed number of transitions between pairs of capacity states. Transition rates calculated in this manner will give accurate results for LOLE and LOEE, but it is important to remember that the assumed number of transitions between states will have an impact on the time-correlated indices such as frequency and duration.

Energy-Limited Units: Type 1 energy-limited units are modeled as thermal units whose capacity is limited on a random basis for reasons other than the forced outages on the unit. This unit type can be used to model a thermal unit whose operation may be restricted due to the unavailability of fuel, or a hydro unit with limited water availability. It can also be used to model technologies such as wind or solar; the capacity may be available but the energy output is limited by weather conditions.

Type 2 energy-limited units are modeled as deterministic load modifiers. They are typically used to model conventional hydro units for which the available water is assumed to be known with little or no uncertainty. This type can also be used to model certain types of contracts. A Type 2 energy-limited unit is described by specifying a maximum rating, a minimum rating, and a monthly available energy. This data can be changed on a monthly basis. The unit is scheduled on a monthly basis with the unit's minimum rating dispatched for all of the hours in the month. The remaining capacity and energy can be scheduled in one of two ways. In the first method, it is scheduled deterministically so as to reduce the peak loads as much as possible. In the second approach, the peak-shaving portion of the unit is scheduled only in those hours in which the available thermal capacity is not sufficient to meet the load; if there is sufficient thermal capacity, the energy of the Type 2 energy-limited units will be saved for use in some future hour when it is needed.

Cogeneration: MARS models cogeneration as a thermal unit with an associated load demand. The difference between the unit's available capacity and its load requirements represents the amount of capacity that the unit can contribute to the system. The load demand is input by specifying the hourly loads for a typical week (168 hourly loads for Monday through Sunday). This load profile can be changed on a monthly basis. Two types of cogeneration are modeled in the program, the difference being whether or not the system provides back-up generation when the unit is unable to meet its native load demand.

Energy-Storage and DSM: Energy-storage units and demand-side management are both modeled as deterministic load modifiers. For each such unit, the user specifies a net hourly load modification for a typical week which is subtracted from the hourly loads for the unit's area.

Transmission System

The transmission system between interconnected areas is modeled through transfer limits on the interfaces between pairs of areas. Simultaneous transfer limits can also be modeled in which the total flow on user-defined groups of interfaces is limited. Random forced outages on the interfaces are modeled in the same manner as the outages on thermal units, through the use of state transition rates.

The transfer limits are specified for each direction of the interface or interface group and can be input on a monthly basis. The transfer limits can also vary hourly according to the availability of specified units and the value of area loads.

Contracts

Contracts are used to model scheduled interchanges of capacity between areas in the system. These interchanges are separate from those that are scheduled by the program as one area with excess capacity in a given hour provides emergency assistance to a deficient area.

Each contract can be identified as either firm or curtailable. Firm contracts will be scheduled regardless of whether or not the sending area has sufficient resources on an isolated basis, but they can be curtailed because of interface transfer limits. Curtailable contracts will be scheduled only to the extent that the sending area has the necessary resources on its own or can obtain them as emergency assistance from other areas.

Emergency Operating Procedures

Emergency operating procedures are steps undertaken by a utility system as the reserve conditions on the system approach critical levels. They consist of load control and generation supplements which can be implemented before load has to be actually disconnected. Load control measures could include disconnecting interruptible loads, public appeals to reduce demand, and voltage reductions. Generation supplements could include overloading units, emergency purchases, and reduced operating reserves.

The need for a utility to begin emergency operating procedures is modeled in MARS by evaluating the daily LOLE at specified margin states. The user specifies these margin states for each area in terms of the benefits realized from each emergency measure, which can be expressed in MW, as a per unit of the original or modified load, and as a per unit of the available capacity for the hour.

The user can also specify monthly limits on the number of times that each emergency procedure is initiated, and whether each EOP benefits only the area itself, other areas in the same pool, or areas throughout the system. Staggered implementation of EOPs, in which the deficient area must initiate a specified number of EOPs before non-deficient areas begin implementation, can also be modeled.

Resource Allocation among Areas

The first step in calculating the reliability indices is to compute the area margins on an isolated basis, for each hour. This is done by subtracting from the total available capacity in the area for the hour the load demand for the hour. If an area has a positive or zero margins, then it has sufficient capacity to meet its load. If the area margin is negative, the load exceeds the capacity available to serve it, and the area is in a loss-of-load situation.

If there are any areas that have a negative margin after the isolated area margins have been adjusted for curtailable contracts, the program will attempt to satisfy those deficiencies with capacity from areas that have positive margins. Two methods are available for determining how the reserves from areas with excess capacity are allocated among the areas that are deficient. In the first approach, the user specifies the order in which an area with excess resources provides assistance to areas that are deficient. The second method shares the available excess reserves among the deficient areas in proportion to the size of their shortfalls.

The user can also specify that areas within a pool will have priority over outside areas. In this case, an area must assist all deficient areas within the same pool, regardless of the order of areas in the priority list, before assisting areas outside of the pool. Pool-sharing agreements can also be modeled in which pools provide assistance to other pools according to a specified order.

Output Reports

The following output reports are available from MARS. Most of the summaries of calculated quantities are available for each load forecast uncertainty load level and as a weighted-average based on the input probabilities.

- Summary of the thermal unit data.
- Summary of installed capacity by month by user-defined unit type.
- Summary of load data, showing monthly peaks, energies, and load factors.
- Unit outage summary showing the weeks during the year that each unit was on planned outage.
- Summary of weekly reserves by area, pool, and system.
- Annual, monthly, and weekly reliability indices - by area and pool, isolated and interconnected.
- Expected number of days per year at specified margin states on an annual, monthly, and weekly basis.
- Annual and monthly summaries of the flows, showing for each interface the maximum and average flow for the year, the number of hours at the tie-line limit, and the number of hours of flow during the year.
- Annual summary of energy and hours of curtailment for each contract.
- Annual summary of energy usage for the peaking portion of Type 2 energy-limited units.
- Replication year output, by area and pool, isolated and interconnected, showing the daily and hourly LOLE and LOEE for each time that the study year was simulated. This information can be used to plot distributions of the indices, which show the year-to-year variation that actually occurs.
- Annual summary of the minimum and maximum values of the replication year indices.
- Detailed hourly output showing, for each hour that any of the areas has a negative margin on an isolated basis, the margin for each area on an isolated and interconnected basis.
- Detailed hourly output showing the flows on each interface.

Program Dimensions

All of the program dimensions in MARS can be changed at the time of installation to size the program to the system being studied. Among the key parameters that can be changed are the number of units, areas, pool, and interfaces.

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