GREENING THE GRID:

Solar and Wind Grid Integration Study for the Luzon-Visayas System of the Philippines

GREENING THE GRID
A Collaboration Between USAID and the Philippines' Department of Energy

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Prepared by

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Cover photo from Energy Development Corporation, showing Energy Development Corporation's Burgos Wind and Solar Project located at Burgos, Ilocos Norte, Philippines

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Foreword

The Department of Energy (DOE) envisions a Philippine energy industry that is globally competitive in utilizing energy in order to create wealth and transform the lives of the Filipinos.

Endowed with an abundant renewable energy (RE) resource, the Philippines is committed to its development and utilization. Consistent with the Philippine Energy Plan, the DOE seeks to fully harness all of its indigenous resource, including the variable renewable energy (VRE).

In view of the increasing solar and wind VRE projects in the pipeline, the DOE sees the need to have a clear direction on how to optimize their development and use. Given the intermittency and technical limitations, these VRE resources may adversely affect the reliability of the Philippine power system.

This Grid Integration Study serves as a positive development in achieving energy security, self-sufficiency, and a low carbon future. Given a different set of scenarios, this study addresses the concerns on VRE penetration, grid integration and the impact on the reliability of the Luzon and Visayas grids. Completed through the active participation of other Philippine government agencies and the private sector, it provides holistic insights and data-based policy recommendations.

The DOE and the members of the Technical Advisory Committee (TAC), would like to thank the United States Agency for International Development (USAID), the US - National Renewable Energy Laboratory (NREL), and USAID-Building Low Emission Alternatives to Develop Economic Resilience and Sustainability (B-LEADERS). Without your assistance, the conclusion of this study would not be possible.

Atty. Felix William "Wimpy" B. Fuentebella
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In addition, the Modeling Working Group benefitted at every stage of this study from the oversight, review, recommendations, and guidance of a diverse Technical Advisory Committee. In addition to the co-chairs, we thank the members of the technical advisory committee (TAC) for their time and contributions:

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Acronyms and Abbreviations

AC	alternating current
AGC	automatic generation control
AUC	area under the curve
BR	best resource scenario
CO_2	carbon dioxide
CREZ	Competitive Renewable Energy Zones
DC	direct current
DOE	Department of Energy of the Philippines
EC-LEDS	Enhancing Capacity for Low Emission Development Strategies
EFOR	equivalent forced outage rates
ERC	Energy Regulatory Commission
GMC	Grid Management Committee
HVDC	high-voltage direct current
IEA	International Energy Agency
lowTx	minimize new transmission requirement scenario
MWG	modeling working group
NGCP	National Grid Corporation of the Philippines
NREL	National Renewable Energy Laboratory
PEMC	Philippine Electricity Market Corporation
PHP	Philippine peso
PV	photovoltaic
QF	qualifying reserve providing facility
RE	renewable energy
TAC	technical advisory committee
TMY	typical meteorological year
USAID	United States Agency for International Development
WESM	Wholesale Electricity Spot Market

Executive Summary

The Republic of the Philippines is home to abundant solar, wind, and other renewable energy (RE) resources that contribute to the national government's vision to ensure sustainable, secure, sufficient, accessible, and affordable energy. Because solar and wind energy increase variability and uncertainty in the power system, significant generation from these resources necessitates an evolution in power system planning and operation. To support Philippine power sector planners in evaluating the impacts and opportunities associated with achieving high levels of variable RE penetration, the Department of Energy of the Philippines (DOE) and the United States Agency for International Development (USAID) have spearheaded this study, which seeks to characterize the operational impacts of reaching high solar and wind targets in the Philippine power system, with a specific focus on the integrated Luzon-Visayas grids.[1]

This study highlights five key findings:

1. RE targets of 30% and 50% are achievable in the power system as planned for 2030. Achieving these high RE targets will likely involve changes to how the power system is operated.
2. System flexibility will contribute to cost-effective integration of variable RE.
3. Achieving high levels of solar and wind integration will require coordinated planning of generation and transmission development.
4. Strategic, economic curtailments of solar and wind energy can enhance system flexibility.
5. Reserve provision may become an issue regardless of RE penetration. Additional qualified reserve-providing facilities (QFs), including from solar and wind generators, and/or enhanced sharing of ancillary services between the Luzon and Visayas interconnections will likely be needed.

Scope and Methodology

This grid integration study uses a production cost model as the primary tool to understand the impacts of increased variable RE on future power system operations. With insights and guidance from the technical advisory committee (TAC), which broadly represents the Philippine power sector, this study focuses on the temporal- and location-specific operational impacts of several scenarios representing the power systems that may serve Luzon and Visayas in the year 2030. The model scenarios are summarized in Table ES-1. The scenarios for 2030 are based on a validated model of the Luzon-Visayas system in 2014, which represents the Reference Case. The scenarios for 2030 add load, generation, and transmission to the 2014 Reference Case according to power sector development plans at the time this analysis was conducted (mid 2016). High RE scenarios extend the 2030 case by adding solar and wind energy generation capacity according to different siting strategies to meet the various RE targets.

For each scenario, the production cost model simulates the hourly scheduling of least-cost electricity for one year under representative weather, load, and outage conditions, while adhering to the physical constraints of the generation fleet and transmission network. The transmission network and conventional generation fleet remain constant for all scenarios representing 2030 systems; different scenarios are created by adjusting the quantity and location of variable RE generators.

[1] This study was formalized via DOE's issuance of Department Circular 2015-11-0017, "Creating a Technical Advisory Committee and Modeling Working Group to Enable Variable Renewable Energy Integration and Installation Targets" (DOE 2015).

Table ES-1. Core Scenarios

Scenario	Renewable energy penetration (as a percentage of annual electricity demand)[a]	Solar and wind siting strategy
2014 Reference Case	25.7%	Existing locations
2030 Base Case	15.0%[b]	Existing and planned (committed) locations
2030 BR30	30% (target)	Best resource
2030 lowTX30	30% (target)	Minimize transmission impacts of new RE
2030 BR50	50% (target)	Best resource
2030 lowTX50	50% (target)	Minimize transmission impacts of new RE

[a] Renewable energy penetration includes generation from biomass, geothermal, hydropower, solar, and wind energy resources. However, each of the high RE scenarios achieves its RE penetration target (30% or 50%) by adding only new solar and wind capacity to the total installed RE capacity captured in the Base Case. Based on feedback from the TAC and DOE's Renewable Energy Management Bureau, all four high RE scenarios assume that 60% of the generation from new variable RE will be met by solar, and 40% will be met by wind. See Table ES-3 for the penetration of variable RE that results from each scenario.

[b] Lower penetration in the Base Case relative to the 2014 Reference Case primarily reflects impacts of higher demand and limited new RE capacity expansion in 2030.

Table ES-2 summarizes the scope and limitations of this effort, which are in part driven by data availability. This study is intended to provide an empirical basis for understanding the potential impacts of high RE penetration levels and the extent to which a variety of strategies can improve the efficiency of variable RE integration. By focusing on the *operational* costs and impacts associated with high RE penetration scenarios, this study is intended to be complementary to other efforts that address different aspects of RE integration, including least-cost capacity expansion planning (with its focus on minimizing total costs of the power system, including fixed costs) and system stability analysis (e.g., contingency response, real and reactive power flow).

Table ES-2. Scope and Limitations

This study **does**:	This study **does not**:
Optimize hourly scheduled dispatch of the Luzon-Visayas system to minimize operating costs.	Include analysis of costs and impacts at the sub-hourly level.
Use existing national generation and transmission expansion plans and projections of electricity demand as the basis for all 2030 scenarios.[a]	Optimize or otherwise evaluate generation and transmission capacity expansion based on capital costs.
Evaluate operational impacts associated with a limited number of solar and wind siting strategies.	Optimize the siting of future solar and wind generators.[b]
Identify periods of system stress (e.g., hours characterized by very high levels of non-synchronous generation).	Analyze system stability and reliability (including contingency response, real and reactive power flow, and voltage).
Represent physical characteristics and constraints of the Luzon-Visayas system at the transmission level (enforcing transmission lines with voltage ratings greater than or equal to 138 kV).	Include representation or analysis of the distribution system, including embedded generation.
Analyze how select changes to solar and wind generator locations and conventional power plant flexibility, transmission, and reserve holdings impact efficient variable RE integration.	Analyze several additional potential sources of power system flexibility, including demand-side management, solar and wind power forecasting, and storage.
Inform policy, system and market operational changes, and technologies that can contribute to a flexible power system that enables the integration of variable RE.	Directly address policy considerations (e.g., RE incentives or retail tariff implications) or evaluate the cost-effectiveness and implementation considerations associated with specific grid-integration strategies (e.g., how markets, regulations, or contracts might need to be revised).

[a] With the exception of the magnitude and location of additional solar and wind generation in the high RE scenarios, which were determined based on guidance from the Technical Advisory Committee.

[b] While the site selection approach attempts to select the best resources based upon annual energy production estimates, subject to land use restrictions and other site selection constraints, the method does not solve a mathematical program to optimize the selection of variable RE resources. Additionally, the site selection approach does not evaluate the efficient resource quantity, in absolute terms or relative to existing resources, required to meet system requirements.

Key Findings and Implications for Power Sector Planners

Five key findings resulted from the scenario and sensitivity analyses undertaken through this modeling effort, with several implications for Philippine power sector planners.

Finding 1: RE targets of 30% and 50% are achievable in the power system as planned for 2030. Achieving these high RE targets will likely involve changes to how the power system is operated.

This study did not find a technical limit to RE penetration: the modeled 2030 Luzon-Visayas system can balance all four high RE scenarios on an hourly basis. This finding indicates that the planned 2030 system has the technical capability to reach a 50% RE target, even when the majority of this RE (up to 37% of annual load) comes from variable solar and wind. Figure ES-1 shows annual modeled generation in 2030 by each generator type in the Luzon-Visayas system for each 2030 scenario. Table ES-3 summarizes total annual RE penetration, annual variable RE (i.e., solar and wind energy) penetration, and curtailment in each of the 2030 scenarios.

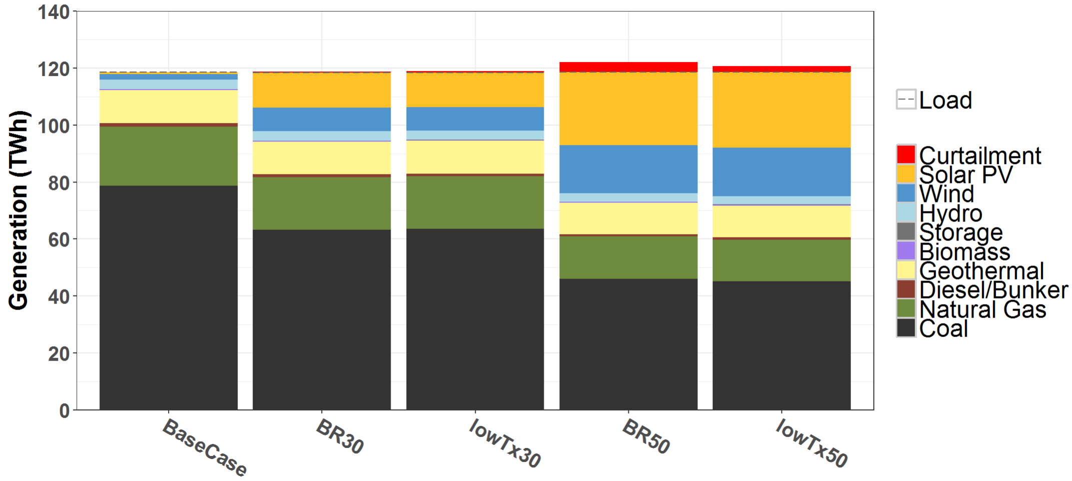

Figure ES-1. Annual Luzon-Visayas system generation by generator type for all five 2030 scenarios

Table ES-3. Annual RE Penetration, Solar and Wind Energy Penetration, and Curtailment in All 2030 Scenarios

Scenario	Annual RE penetration	Annual solar and wind energy penetration	Annual solar and wind energy curtailment
Base Case	15.0%	2.1%	0%
BR30	30.1%	17.5%	1.0%
lowTx30	29.9%	17.3%	1.9%
BR50	47.9%	35.9%	7.6%
lowTx50	48.8%	36.8%	4.4%

Importantly, all modeled 2030 scenarios assume the addition of generation and transmission capacity based on existing power sector development plans outlined by DOE and the National Grid Corporation of the Philippines (NGCP). These additions represent significant expansion beyond the power system infrastructure that exists today and will aid the integration of variable RE, likely resolving some of the integration-related issues that have been observed since 2014.

In the 2030 scenarios, variable RE displaces generation primarily from coal and natural gas, leading to an *18%–40% reduction in thermal fuel consumption* and a *19%–41% reduction in greenhouse gas emissions* relative to the Base Case. In addition, because of the increased variability associated with higher levels of variable RE, the 30% and 50% RE scenario results show several operational changes relative to the Base Case. For example, conventional generators (especially coal and natural gas) start and stop more frequently, spend more time at their minimum stable output levels, and experience more significant ramps. These changes—which are most significant in the 50% RE scenarios for natural gas and coal—impact the capacity factors of different generator types. Notably, the capacity factor of natural gas and coal plants decline in all high RE scenarios relative to the Base Case.

Finding 2: System flexibility will contribute to cost-effective integration of variable RE.

The operational changes associated with the high RE scenarios highlight the crucial role of power sector flexibility[2] in achieving significant levels of variable RE on the grid. Numerous options are available to improve the flexibility of the Philippine power system and will involve a balance between adjusting institutional practices and making capital investments. Accessing and utilizing the inherent flexibility of existing resources represents the most cost-effective initial pathway to enabling the efficient integration of variable RE. For example, optimal scheduling of the generation fleet according to technical generator capabilities will contribute to cost-effective integration of variable RE. Figure ES-2 shows an extreme example of how the hourly scheduling of the conventional fleet changes in the 2030 BR30 and BR50 scenarios relative to the 2030 Base Case, focusing on a day when peak demand occurs after the sun has set. New or updated regulations, policies, and/or market mechanisms (for instance, flexibility-related products in the Philippines' new ancillary service market) may be required to encourage this high level of flexible operation of generators.

[2] Flexibility refers to the ability of the power system to respond to changes in electricity load and generation.

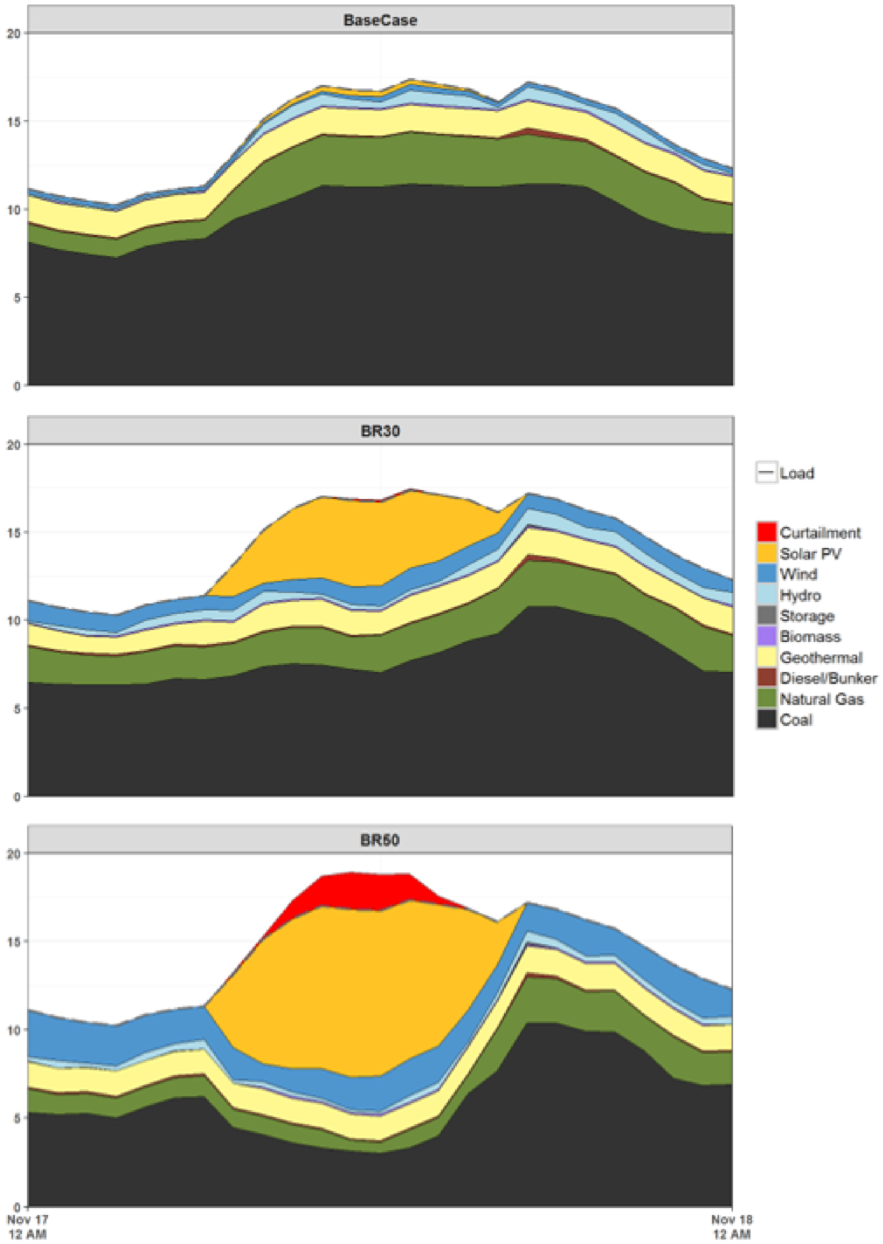

Figure ES-2. Hourly generation schedule on November 17 (Visayas evening peak day) in the Base Case, BR30, and BR50 scenarios

For new generation assets, selecting the most flexible technologies will help achieve a modern and responsive fleet that can meet a variety of goals. In addition, adopting best practices for reliable and efficient power system operations will help to integrate variable RE resources. The Philippine power sector is already implementing and/or planning several actions that will enhance flexibility in the near term. For example, NGCP recently implemented a wind and solar power forecasting program, and the Philippine Electricity Market Corporation is adding sub-hourly resolution to the market and will soon open ancillary service markets that will enable the co-optimization of energy and dispatchable reserves scheduling. Flexibility can be further enhanced by expanding the market to co-optimize the scheduling of energy and all operational reserve products, including primary and secondary reserves. Over the longer term, additional investments in transmission, demand response, and storage may also help to enhance the utilization of variable RE, especially if the Philippines seeks to enable very high levels of variable RE (e.g., a 50% RE target).

Beyond enabling the integration of solar and wind generation, flexibility is a critical component of overall electricity sector modernization and benefits the objectives of the Philippine power sector, including improved reliability and resilience, diversification of energy sources, reduced environmental impacts, utilization of indigenous resources, and reduced cost to the consumer. Power sector decision makers can therefore achieve multiple objectives by targeting system flexibility in operations and planning procedures.

Finding 3: Achieving high levels of solar and wind integration will require coordinated planning of generation and transmission development.

This study evaluated two approaches to siting new solar and wind generators: the Best Resource ("BR") scenarios site these generators in the areas of Luzon and Visayas that have the best solar and wind resources, regardless of transmission availability, while the Minimize Transmission Impacts ("lowTx") scenarios site RE generators in areas that seek to minimize the need for new transmission capacity. At 30% RE penetration, the difference between the modeled results of the BR30 and lowTx30 scenarios are negligible for most metrics, and total annual curtailment[3] of solar and wind is less than 2% in each scenario. These results imply that at a 30% RE penetration, the 2030 power system is flexible enough to manage the impacts when variable RE resources are distributed across the power system based on either approach to RE siting. However, at 50% RE penetration, the differences between the results of BR and lowTx scenarios become more pronounced. Perhaps most notably, annual curtailment in the BR50 scenario (7.6%) is significantly higher than that of the lowTx50 scenario (4.4%). Driven at least in part by these higher levels of variable RE curtailment, variable costs and thermal fuel consumption are 1.4% and 1.7% higher in the BR50 scenario relative to the lowTx50 scenario, respectively.

The results of the lowTx50 scenario indicate that the Philippines can achieve high RE levels while minimizing issues such as transmission congestion and curtailment by encouraging solar and wind development in robust areas of the planned 2030 transmission system. Thus, strategically siting solar and wind generation can reduce the need for transmission investments that would otherwise be needed to manage curtailment, especially at very high (e.g., 50%) RE penetrations.

On the other hand, the BR scenarios identified several zones that are home to some of the Philippines' highest quality RE resources but where planned transmission may be insufficient to utilize these resources to their fullest potential. When the transmission flow limits of 22 congested lines are increased by 50% above their original rated capacities to simulate the impacts of additional transmission capacity, RE curtailment in the BR50 scenario falls from 7.6% to 3.8%. Recognizing that the Philippine transmission planning process is dynamic and will involve numerous iterations between the publication of this study and 2030, this study highlights opportunities for additional strategic investments in transmission infrastructure (e.g., network expansion or upgrade) that can help to facilitate development of the Luzon and Visayas interconnections' highest-quality RE resources to enable the lowest-cost solar and wind resource integration. To improve the ability of the Philippine power system to take advantage of the country's lowest-cost indigenous solar and wind resources, power system planners can consider more closely coordinating the clean energy generation and transmission system planning processes.

This study did not seek to optimize solar and wind siting (nor the magnitude of installed capacity for each of these resources) so should not serve as the sole basis of decisions regarding ideal locations of future solar and wind power plants. Philippine power sector planners can further evaluate different approaches to siting new RE resources through capacity expansion modeling activities, which provide insight into development trajectories and guide policy design to achieve the desired outcome.

[3] In this study, curtailment is calculated by subtracting modeled solar and wind energy generation from available solar and wind energy over a particular period. Percent curtailment is curtailment divided by total available solar and wind energy.

Finding 4: Strategic, economic curtailments of solar and wind energy can enhance system flexibility.

Solar and wind curtailment occurs in all high RE scenarios, though at different levels depending on RE penetration and locations, as shown in Table ES-3 and Figure ES-2. Drivers of curtailment include transmission flow limits, lack of conventional generator flexibility, and conventional generator startup and shutdown costs. Minimizing curtailment is an important step towards lowering the cost of operating the power system and can help address stakeholder concerns regarding revenue sufficiency of RE generators. However, curtailment need not be zero for successful solar and wind integration; in fact, strategic curtailment is an important tool that the power system operator can draw upon to support flexible, economic power system operation without investing in the generation and transmission infrastructure necessary to eliminate curtailment.

Under current Philippine laws and regulations, the system operator can curtail solar and wind for reliability reasons; however, RE generation receives preferential dispatch, which prevents the *economic* curtailment of variable RE, such as when curtailing RE is cheaper from a system perspective than shutdown and startup costs associated with reducing generation from a coal plant. As the Philippines increases the penetration of variable RE on the power system, economic curtailment of solar and wind generation will become an increasingly important source of power system flexibility. Enabling strategic, economic curtailment may involve reviewing and, if necessary, revising laws, rules, and operational practices that mandate preferential RE dispatch. It may also involve updating power supply agreements with solar and wind generators to enable economic as well as reliability-related curtailment by the power system operator.

Finding 5: Reserve provision may become an issue regardless of RE penetration. Additional QFs, including from solar and wind generators, and/or enhanced sharing of ancillary services between the Luzon and Visayas interconnections will likely be needed.

While a full reliability analysis is beyond the scope of this study, the 2030 scenarios identify potential impacts of high RE scenarios on certain elements of reliability—namely, the holding of reserves. Figure ES-3 shows the annual modeled reserve provision in each of the 2030 scenarios. These scenarios assume the provision of downward reserves from wind and solar generators. Based on these results, the 2030 Luzon-Visayas system may face reserve shortages in all scenarios. Reserve shortages are particularly large for upward reserves—especially in the Visayas interconnection—under the requirements assumed in this study. Reserve shortage results from two related factors: the capacity adequacy of the system and the availability of QFs.

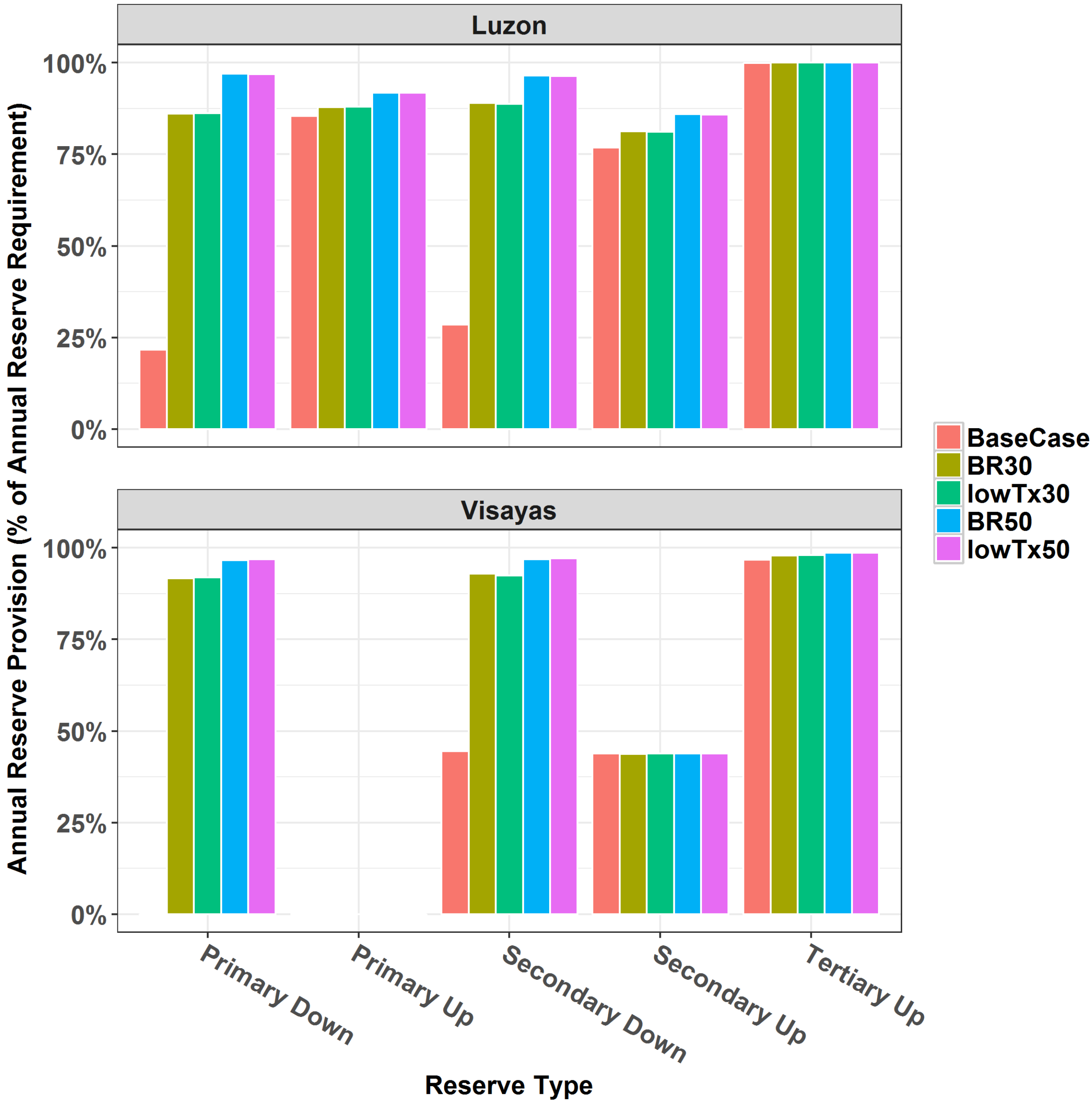

Figure ES-3. Annual modeled reserve provision by reserve product in the Luzon and Visayas grids

Annual reserve provision is expressed as a percentage, which is calculated by dividing the simulated annual provision by the requirement for each reserve product in each of the two grids.

Sensitivity analyses indicate that qualifying more generators to provide ancillary services and enhancing the capability to share reserves across the high-voltage direct current cable that connects the Luzon and Visayas interconnections will help reduce reserve shortages in 2030. The definition of reserve requirements, and the ability of QFs to provide fast-response capabilities, will help ensure reliable system operations and enable variable RE integration. Thus, procuring and/or accessing flexible capabilities of conventional generators will be crucial to meeting high RE goals. Furthermore, broadening generation planning to consider not only forecasted peak demand but also the necessary flexibility to respond to net load variability will help create a framework in which these procurement decisions can be evaluated.

This study also demonstrates that variable RE (specifically, wind plants) can contribute to ancillary service provision. The implementation of these technologies can enable solar and wind generators to help supply grid services. New or updated institutional measures such as grid codes and power supply agreements may be needed to encourage new variable RE generators to implement technical capabilities to provide a variety of reserves.

Conclusions

This study has delineated various impacts of RE integration on system operation and provides insight to ongoing discussions within the Philippine electricity industry on the promises and implications of increased variable RE (wind and solar) integration. The study confirms, for the case of the Philippines, what an increasing number of similar country-level and regional studies also indicate on a global level: High shares of variable RE, well above 20%, are technically achievable. Specifically, this study highlights five key findings:

1. RE targets of 30% and 50% are achievable in the power system as planned for 2030. Achieving these high RE targets will likely involve changes to how the power system is operated.
2. System flexibility will contribute to cost-effective integration of variable RE.
3. Achieving high levels of solar and wind integration will require coordinated planning of generation and transmission development.
4. Strategic, economic curtailments of solar and wind energy can enhance system flexibility.
5. Reserve provision may become an issue regardless of RE penetration. Additional QFs, including from solar and wind generators, and/or enhanced sharing of ancillary services between the Luzon and Visayas interconnections will likely be needed.

As the capital costs of solar and wind technologies continue to fall, the economic deployment of these abundant resources will become increasingly possible, and contribute to the development of a least-cost power system. These five key findings will help guide proactive planning for higher penetrations of variable RE and prepare the Luzon-Visayas system for the increased variability and uncertainty associated with these technologies, while also supporting the development of a more flexible, modern, and economic power system. Integrating high levels of variable RE requires an evolution in power system planning and operation. This study, along with the other power system planning analyses such as capacity expansion and load flow analysis, can inform that evolution and contribute to the analytical basis for addressing the technical barriers to achieving a low-cost, clean, reliable, and flexible Philippine power system.

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1 Introduction

The Republic of the Philippines is advancing its power sector planning and development with the goal of ensuring sustainable, stable, secure, sufficient, accessible, and affordable energy. Blessed with abundant indigenous renewable energy (RE) resources, the Philippines can draw upon resources such as solar and wind to help achieve this vision. Recognizing this potential, the Philippines has established national policy through legislation such as the Electric Power Industry Reform Act of 2001 and the Renewable Energy Act of 2008 to promote the development of domestic RE resources. In addition, clean energy technologies such as RE are likely to play an important role in the formulation and implementation of the Philippines' Nationally Determined Contribution targets, which are associated with the country's accession to the Paris Agreement on climate change.

Moreover, the costs of clean energy technologies are consistently falling, and in many countries, new solar and wind power plants are now competitive with conventional generators (International Energy Agency and Nuclear Energy Agency 2015). In this context, and in the spirit of broader grid modernization, Philippine power sector planners are interested in preparing the power system grid to reliably and cost-effectively integrate RE, especially variable generation technologies. Further, in determining potential RE installation targets, the Department of Energy of the Philippines (DOE) deems it necessary to ensure the efficient and effective absorption to the grid of RE-generating capacities, evaluate the impacts of increasingly ambitious RE targets, and assess actions to cost-effectively improve the integration of variable RE sources into the grid (DOE 2015).

Globally, many countries have demonstrated that high levels of variable RE in the power system are achievable, particularly in conjunction with robust planning. Such planning is the focus of this report. We use a detailed production cost model with temporal- and location-specific weather data to simulate the operation of the Philippine power system (specifically, the Luzon-Visayas system). We use this model to characterize how the added variability of wind and solar affects operations under a variety of conditions, including various combinations of weather, load size, and generator availability. With this information, we then evaluate how altering aspects of the power system—for example, solar and wind generator locations, coal flexibility, transmission, and reserve holdings—affect the integration of RE and cost of serving electric demand.

This study is co-led by DOE and the United States Agency for International Development (USAID) and is conducted under the Enhancing Capacity for Low Emission Development Strategies (EC-LEDS) partnership between the governments of the Philippines and the United States. This report addresses wind and solar integration specific to the Luzon-Visayas power system—impacts, challenges, and potential improvements. The model created for the study is designed to serve as a platform for continued analysis as new questions arise and additional information and data become available.

1.1 Grid Integration—Challenges and Opportunities

Wind and solar can be characterized by their variability and uncertainty. They are variable in that their generation is based on the underlying intensity of the wind and solar resource; they are uncertain in that their generation output cannot be perfectly predicted. Because power systems are already designed to manage variability and uncertainty from other sources, such as load and generator outages, they are typically already able to manage wind and solar generation at low penetration levels. As wind and solar penetration levels increase, however, changes to how the system is operated may be necessary to manage the variability. Namely, system flexibility—the ability of the power system to respond to changes in electricity load and generation (through, for example, conventional generators having the capability to adjust output in response to changing load and weather conditions)—becomes more important.

One sign of system inflexibility is RE curtailment, which is the reduction in output of a wind or solar plant from what it would otherwise be able to generate given available resources. A plant might need to be curtailed if, for example, other generating units must remain on in spite of having higher costs of electricity production. This can happen if a coal plant must remain on if its generation is needed at a later hour, and the cost of shutting down and restarting the coal plant exceeds the costs of generating electricity using coal instead of RE.

Simulating the power system with increased levels of wind and solar can highlight whether the system is sufficiently flexible to meet load with minimal RE curtailment.[4] If not, experience elsewhere has highlighted many options for improving system flexibility. Sources of flexibility can come from generation (e.g., generators with faster ramp rates or lower minimum stable output levels), transmission networks (e.g., better interconnections), flexible demand and storage (e.g., adjusting the load shape to better correspond with RE generation), and operations (e.g., incorporating RE into unit commitment and dispatch) (Cochran et al. 2015). In many cases, investments or institutional changes that enhance power system flexibility will contribute toward a secure, reliable, cost-effective, and flexible power system regardless of the level of RE in the power mix.

The value and cost of each integration strategy is system-specific. An effective approach in Denmark or India may not have an impact in the Philippines. This study tests several such sources of flexibility on the Luzon-Visayas system, using RE curtailment, production costs, and other metrics to evaluate effectiveness.

1.2 Technical Advisory and Modeling Working Groups

Recognizing the challenges associated with variable RE generation, *Section 20: Intermittent RE Resources* of the Philippine Renewable Energy Law directs Philippine power sector actors to determine the "maximum penetration limit of the Intermittent RE-based power plants to the Grid, through technical and economic analysis" (Congress of the Philippines 2008). To contribute to this objective and to understand the implications of significant variable RE integration for power system planning and operations more broadly, DOE issued Department Circular 2015-11-0017 to create a technical advisory committee (TAC) and modeling working group (MWG) to evaluate variable RE integration and installation targets (DOE 2015). According to the Department Circular, the goal of the TAC and MWG is to conduct a grid integration study to identify:

- Potential grid reliability concerns associated with the scaling of variable RE
- Options to improve system flexibility and power system balance
- New installation and grid integration targets.

The TAC met three times (see Table 1 and Appendix D) to provide guidance at different stages of the process—from prioritizing study questions and study scenarios, to validating modeling assumptions, to suggesting improvements to draft results. The TAC comprises representatives from government agencies, system operators and regulators, power producers, distribution utilities, and international grid experts, among others.

Table 1. TAC Meetings

Meeting Date	Meeting Topics
January 21, 2016	Scenario design and modeling assumptions
June 3, 2016	2014 Reference Case results and validation, 2030 model design, solar and wind site selection strategy
February 3, 2017	2030 model results and policy implications

Equally significant to the study was the formation of the MWG. The MWG reflects collaboration among key stakeholders in the Philippine power system: DOE, the Grid Management Committee (GMC), the

[4] Some curtailment may be a *source* of cost-effective system flexibility.

National Grid Corporation of Philippines (NGCP), the Philippine Electricity Market Corporation (PEMC), and the U.S. Department of Energy's National Renewable Energy Laboratory (NREL).

1.3 Scope of Study

The objective of this study is to evaluate the impact of RE (with a focus on solar and wind) generation on the operations of the Luzon-Visayas power system in 2030. We test this impact using five different sets of RE capacities that vary in their magnitude and locations, as will be discussed further in Section 2 and Section 3. We then evaluate options to improve RE integration by testing changes that reduce operating costs and RE curtailment, while improving reserve holdings and meeting demand at all hours of the year.

The report assumes that, in our study year, all installation decisions have already been made and fixed costs are sunk. The report does not evaluate the merits of different build-out projections in terms of capital costs. Instead, the study seeks to take a given future system and minimize the cost of operating that system. Thus, this study is intended to be complementary to other studies that address different aspects of RE integration, including least-cost capacity expansion (with its focus on minimizing total costs of the power system, including fixed costs) and system stability (contingency response, real and reactive power flow). Also, the study informs but does not directly address policy considerations related to RE, including RE incentives and retail tariff implications. Finally, while our analysis considers the value of changes to system flexibility, we do not evaluate the implementation of grid integration strategies, such as how markets, regulations, or contracts might need to be revised or the overall cost-effectiveness of each strategy, such as whether operating coal plants more flexibly is worth the added costs in wear and tear and shortened life. Instead, this study is intended to provide an analytical basis for understanding the impact of high RE penetration levels and relative impact of strategies to reduce operating costs and RE curtailment.

This study focuses specifically on Luzon and Visayas because these interconnected systems are linked via a high-voltage direct current (HVDC) intertie and effectively can be modeled as one grid that serves the majority of the population in the Philippines. Additionally, at the time of study commencement, the Philippine Wholesale Electricity Spot Market (WESM) was limited to the Luzon and Visayas interconnections.[5] Although the scope of this initial grid integration study does not include Mindanao, as a result of this effort, the MWG will have the capability to conduct follow-on modeling. Expanding the study to cover Mindanao is a potential priority for future work.

Finally, this study focuses only on transmission-scale impacts of high RE. Impacts at the distribution level are beyond our scope.

1.4 Structure of Report

The remainder of the report is structured as follows: Section 2 reviews the methodology and study assumptions; Section 3 reviews RE site selection and methodology for creating RE generation profiles; Section 4 reviews operational impacts and modeling results; Section 5 reviews major findings and implications for policy; and Section 6 concludes.

[5] PEMC has since implemented the Interim Mindanao Electricity Market to initiate the market design process specifically for Mindanao.

2 Methodology and Assumptions

This study assesses the operational impacts of achieving significant wind and solar generation in the Luzon-Visayas system. The analysis platform for the study is Energy Exemplar's PLEXOS production cost model, a commercially available software package that has served as the basis for several RE grid integration studies conducted in the United States, India, and elsewhere (e.g., Bloom et al. 2016; Lew et al. 2013; GE Energy Consulting 2014).

The production cost model allows us to simulate the operation of the Luzon-Visayas system with the added variability of wind and solar and therefore understand how the system is balanced at hourly time steps for a year, under a variety of weather, load, and outage conditions. We can then use the tool to understand how changes to the underlying system (e.g., operating rules, RE locations, transmission) can reduce the operational impacts of achieving this system balance or achieve other objectives, such as reduced curtailment.

Production cost models optimize the operation of a given power system to minimize operating costs, subject to physical and economic constraints. The model assumes that each plant that is not on an outage is available for scheduling (unit commitment) within its physical constraints. Physical constraints include characteristics such as ramp rates, minimum hours the unit must be operating or off, and minimum stable output levels if on. To simulate day-ahead unit commitment, the model schedules the combination of generating units with the least operating costs to meet demand and reserve requirements based on RE and load forecasts. We run the model hourly for a full year for the Luzon-Visayas system.

Due to data limitations, we only simulate the forecasted unit-commitment and dispatch schedule through a day-ahead market. We do not use the model to simulate deviations between the day-ahead schedule and real-time operations (i.e. we do not simulate actual dispatch which might include deviations from the day-ahead schedule, for example, due to forecast error or unplanned outages). We also do not consider other factors that affect scheduling, such as bilateral contracts; thermal plants that are must-run for reliability purposes; and bidding behavior, including self-scheduling (the model assumes all generators bid their assumed marginal cost and capability). Finally, due to the lack of sub-hourly load and weather data, we do not use the model to simulate intra-hour operations and impacts.

Figure 1 illustrates the overall methodology used in this study. First, the MWG built and validated a model of the existing (2014) power system. The MWG then added load, generation, and transmission to meet projections for 2030, including solar and wind capacity to reflect various RE targets. Finally, the MWG simulated power system operations in 2030 under several high and low RE scenarios and sensitivity analyses.

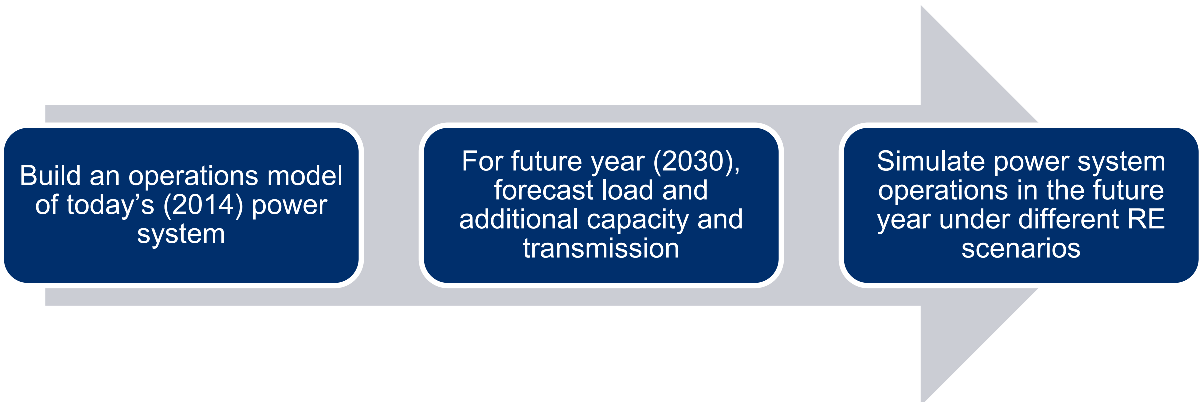


Figure 1. Overview of the approach to this study

Figure 2 provides further details on inputs to the production cost model, which the remainder of this section and Section 3 describe in further detail.

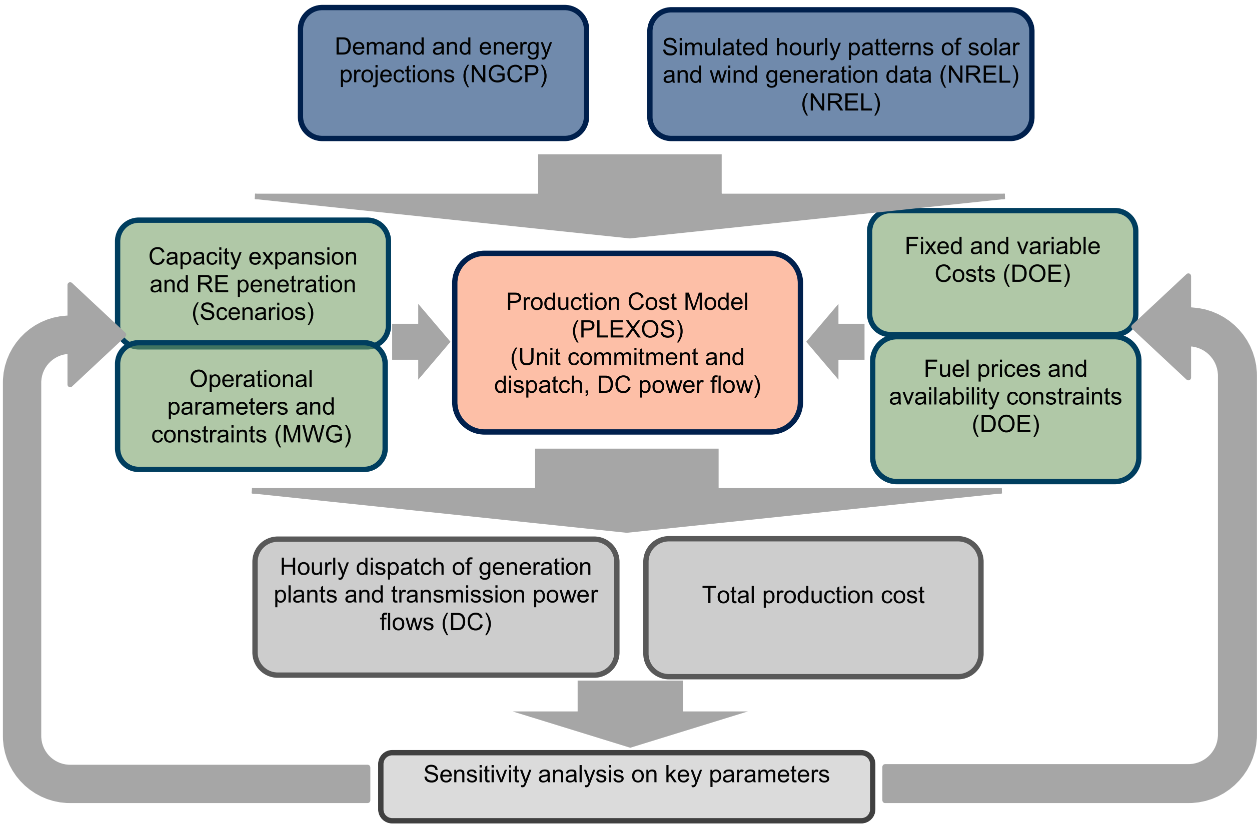


Figure 2. Inputs and outputs of the production cost model

2.1 Study Scenarios

This study comprises six **core scenarios**: the 2014 Reference Case, the 2030 Base Case, and four high RE scenarios for 2030 (summarized in Table 2). The TAC defined these scenarios during its first meeting with the goal of developing a study that addresses key concerns of electricity sector stakeholders.

Table 2. Core Scenarios

Scenario	Renewable energy penetration (as a percentage of annual electricity demand)[a]	Solar and wind siting strategy
2014 Reference Case	25.7%	Existing locations
2030 Base Case	15.0%[b]	Existing and planned (committed) locations
BR30	30% (target)[c]	Best resource
lowTx30	30% (target)	Minimize transmission impacts of new RE
BR50	50% (target)	Best resource
lowTx50	50% (target)	Minimize transmission impacts of new RE

[a] Renewable energy penetration includes generation from biomass, geothermal, hydropower, solar, and wind energy resources. However, each of the high RE scenarios achieves its RE penetration target (30% or 50%) by adding only new solar and wind capacity to the total installed RE capacity captured in the Base Case. Based on feedback from the TAC and DOE's Renewable Energy Management Bureau, all four high RE scenarios assume that 60% of the generation from new variable RE will be met by solar, and 40% will be met by wind. See Section 3 for more details.

[b] Lower penetration in the Base Case relative to the 2014 Reference Case primarily reflects impacts of higher demand and minimal new RE capacity expansion in 2030.

[c] RE penetration, a function of RE generation, is an output of the production cost model rather than an input. The MWG iterated solar and wind capacities in each scenario to produce penetration levels that are very close to the target. Thus, the total RE penetration for each high RE scenario is not exactly 30% or 50% but is within 1% of the target. See Section 4.1 for more details.

2014 Reference Case. Although the primary focus of this study is the impact of significant variable RE on the 2030 power system, the MWG created the model for a recent historic year, 2014, to validate the model. The purpose of the 2014 Reference Case is to test the modeling assumptions to ensure the production cost model produces realistic results compared with an actual year of operation. Appendix A provides a presentation that compares several metrics from the 2014 Reference Case model solutions to actual operational data from the Luzon-Visayas system in 2014.

As the following sections detail, the 2014 Reference Case is based largely on actual 2014 operational data provided by the MWG member agencies. The MWG chose 2014 as the reference year primarily because of data availability. Specifically, 2014 is the most recent year for which complete, time-synchronous hourly load, solar resource, and wind resource data are available. These time-synchronous data sets are essential for grid integration modeling because they capture correlations between electricity demand and solar and wind generation, all of which are driven in part by weather patterns.

2030 Base Case. The 2030 Base Case is a "business-as-usual" scenario that assumes the Philippine power sector will develop in line with current policies and plans. The Base Case takes the 2014 Reference Case as its starting point and projects load growth, new generation capacity, and new transmission capacity, as the following sections detail. The 2030 Base Case assumes *no new RE development* beyond that which has been implemented or committed through 2016. The Base Case therefore represents a relatively low RE scenario against which to compare the high RE cases. In fact, as Table 2 shows, the proportion of RE in the generation mix decreases from approximately 25% in 2014 to 15% in 2030 because the business-as-usual scenario includes significant demand growth but relatively little new RE development.

2030 High RE Cases. The TAC chose four high RE scenarios for 2030, which vary based on two factors of interest for RE development:

Total target penetration of RE. The TAC chose two penetration targets for total RE (including biomass, geothermal, hydro, solar, and wind): 30% and 50% of total annual energy demand. Because the focus of this study is on evaluating the impacts of significant *variable* RE on system operations, the high RE scenarios attain the 30% and 50% penetration targets by adding new solar and wind generation to the RE and conventional generation planned in the 2030 Base Case. Thus, these scenarios do not include any additional biomass, hydro, and geothermal generation beyond that already represented in the Base Case.

Solar and wind siting strategy. The high RE scenarios reflect two approaches to siting new variable RE generators: (1) siting generators in the areas of Luzon and Visayas with the best solar or wind resources, regardless of transmission availability (the Best Resource [BR] scenarios); and (2) siting generators in areas that potentially minimize the need for new transmission capacity (the lowTx scenarios). Section 3.1 describes the methodology for siting new solar and wind generators according to these two strategies.

As Table 2 shows, each of the four high RE scenarios represents a unique combination of target RE penetration and solar and wind siting strategy. In addition to the scenarios summarized in Table 2, we designed and simulated several sensitivity scenarios to further explore key issues surrounding generation fleet flexibility, transmission capacity, and reserve qualifying facilities. The design and results of these sensitivity scenarios are documented in Sections 4.3.2, 4.4.2, and 4.5.2, respectively.

2.2 Input Data

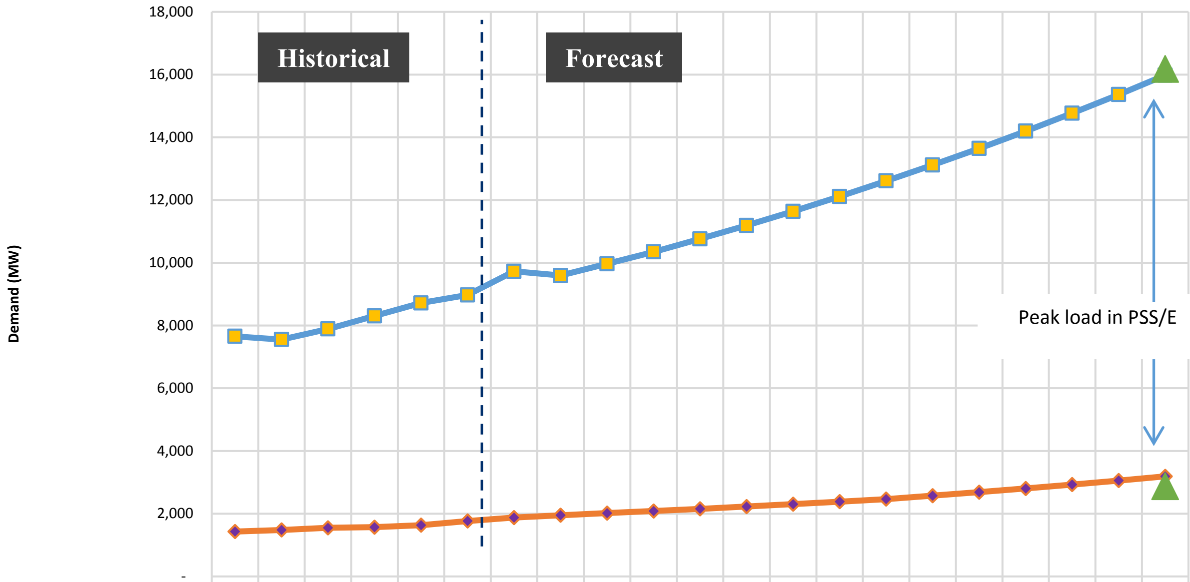
This study is based on a multitude of data inputs, most of which the MWG agencies (DOE, GMC, NGCP, and PEMC) shared under a multiparty non-disclosure agreement. Appendix A includes a general list of data sources. These data enabled the MWG to customize the data set to simulate the Luzon-Visayas system operations. In the few cases in which local data were not available (e.g., generator start and stop costs), the MWG used representative data from the United States and India.

Among the most important data sources for this study are NGCP's PSS/E load flow cases for 2014 and 2030 peak load periods. PSS/E is an operational planning model that simulates power flow throughout the interconnection during a given period. NGCP created load flow cases for the peak load hour of the year for both 2014 and 2030 to inform transmission planning studies. The load flow models contain transmission network and generator details, including physical attributes of nodes, transmission lines, transformers, and generators. The following sections describe how the load flow cases, along with other data from the MWG agencies, served as inputs to the PLEXOS model.

2.3 Electricity Demand

In both the 2014 and the 2030 scenarios, this analysis uses hourly electricity load (demand) profiles to define the required level of generation for every dispatch period. For the 2014 Reference Case, NGCP provided actual hourly load from 2014 for each of the Luzon and Visayas grids. In addition, the 2014 PSS/E load flow case includes node-level peak load values, which define the fraction of peak load associated with each node in the system. The MWG applied the peak load participation factors to every hour of the year. This approach represents a simplification in the absence of spatially resolved hourly load data.

The basis for electricity demand in 2030 is the peak load estimate included in NGCP's 2030 PSS/E load flow case. The system-wide peak load from the 2030 load flow case is based primarily on 2030 projected load from DOE's *Distribution Development Plan,* with some adjustments by NGCP (as Figure 3 illustrates).



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
LUZON	7,656	7,552	7,889	8,305	8,717	8,974	9,726	9,594	9,967	10,34	10,76	11,18	11,63	12,11	12,60	13,11	13,64	14,19	14,76	15,36	15,98
VISAYAS	1,431	1,481	1,551	1,572	1,636	1,768	1,878	1,950	2,019	2,087	2,154	2,228	2,305	2,384	2,466	2,575	2,688	2,806	2,929	3,057	3,192
2030 PSS/E Luzon																					16,182
2030 PSS/E Visayas																					2,876

Figure 3. Electricity demand projection for Luzon and Visayas, 2016–2030

Source: DOE

Under the assumption that average load growth equals peak load growth, the MWG applied the peak load growth rate between the 2014 and 2030 load flow cases to every hour of the year to develop time series load data for 2030. Thus, while its magnitude changes, the shape of the hourly load profile remains constant between the 2014 and 2030 models. One exception is extreme events that impacted electricity demand in 2014 (e.g., Typhoons Glenda and Ruby, which led to widespread electricity outages). In these cases, the MWG adjusted the affected hours in 2030 by averaging demand for the same hour of the preceding and following weeks.

Additionally, the MWG used the 2030 load flow case to determine node-level participation factors for the 2030 model. As with the 2014 model, the MWG applied these participation factors to every hour of the year to define the distribution of demand across the modeled interconnection.

2.4 Electricity Generation Capacity

The model for this effort uses data on the quantity and characteristics of generating capacity in Luzon and Visayas. These data primarily come from two sources: NGCP's load flow cases for 2014 and 2030 and unit-specific generator information from DOE. Key inputs to the model include the following details for each generating unit. These unit-specific input data collectively define the physical characteristics of generators that influence unit commitment and economic dispatch. In cases where unit-specific data were not available, the MWG applied averages by fuel type based on data available for other units.

- Generator prime mover and fuel type (e.g., diesel/bunker steam turbine, natural gas combined cycle)
- Dependable capacity[6]
- Minimum stable output level

[6] Dependable capacity is the maximum capacity that a given unit is able to reliably achieve. In some cases, dependable capacity is lower than nameplate capacity of that unit.

- Ramp rate
- Full and partial heat rates
- Commissioning date
- Location (i.e., the bus at which each unit is connected to the transmission system).

The generating capacity in the 2014 Reference Case reflects the majority of actual installed capacity interconnected to the Luzon and Visayas grids during that year. As summarized in Table 3, the installed capacity in the 2014 Reference Case is 14,426 MW, consisting of 34% coal, 19% natural gas, 17% oil (diesel/bunker[7]), and 29% RE (2% solar and wind).

Because this study is not a capacity expansion modeling exercise, this study does not attempt to simulate the optimal build out of new generation (or transmission) through time. Rather, generating capacity in each 2030 scenario represents a "snapshot" of a possible future system. Specifically, generating capacity in the 2030 Base Case is based on NGCP's 2030 load flow case, which includes:

- Installed capacity in the 2014 Reference Case
- New units that were constructed in 2015 and 2016
- Committed new capacity for Luzon and Visayas, based on DOE's "2016 Private Sector Initiated Power Projects" as of June 2016 (DOE 2016)
- Indicative new coal and natural gas units for Luzon and Visayas, based on DOE's "2016 Private Sector Initiated Power Projects" as of June 2016.

The 2030 Base Case includes 10,420 MW of additional installed capacity beyond that installed in 2014 (see Table 3). The fuel mix in the 2030 Base Case is 49% coal, 20% natural gas, 11% oil, and 20% RE (4% solar and wind). The 2030 scenarios do not include any retirements of existing units. Figure 4 shows the approximate location and capacity of installed generating units in the Base Case, including the distribution of generating capacity across the various zones defined in the model (which are described further in Section 2.5).

Table 3. Installed Generating Capacity (and Percent of Total) in the 2014 and 2030 Models

Fuel	2014 Installed Capacity (MW)	2030 Installed Capacity: Base Case (MW)	Capacity Additions: 2014-2030 (MW)
Biomass	32 (<1%)	96 (<1%)	63
Coal	4,974 (34%)	12,188 (49%)	7,214
Diesel/Bunker	2,416 (17%)	2,743 (11%)	309
Gas	2,789 (19%)	4,919 (20%)	2,130
Geothermal	1,478 (10%)	1,518 (6%)	40
Hydro	1,738 (12%)	1,738 (7%)	-
Solar	21 (<1%)	483 (2%)	462
Storage	736 (5%)	736 (3%)	-
Wind	240 (2%)	442 (2%)	202
Total	**14,426**	**24,846**	**10,420**

[7] The diesel/bunker fuel type represents all generators fueled with oil derivatives. In this context, bunker fuel refers to fuel oil (typically No. 6 fuel oil) transported via shipping vessel.

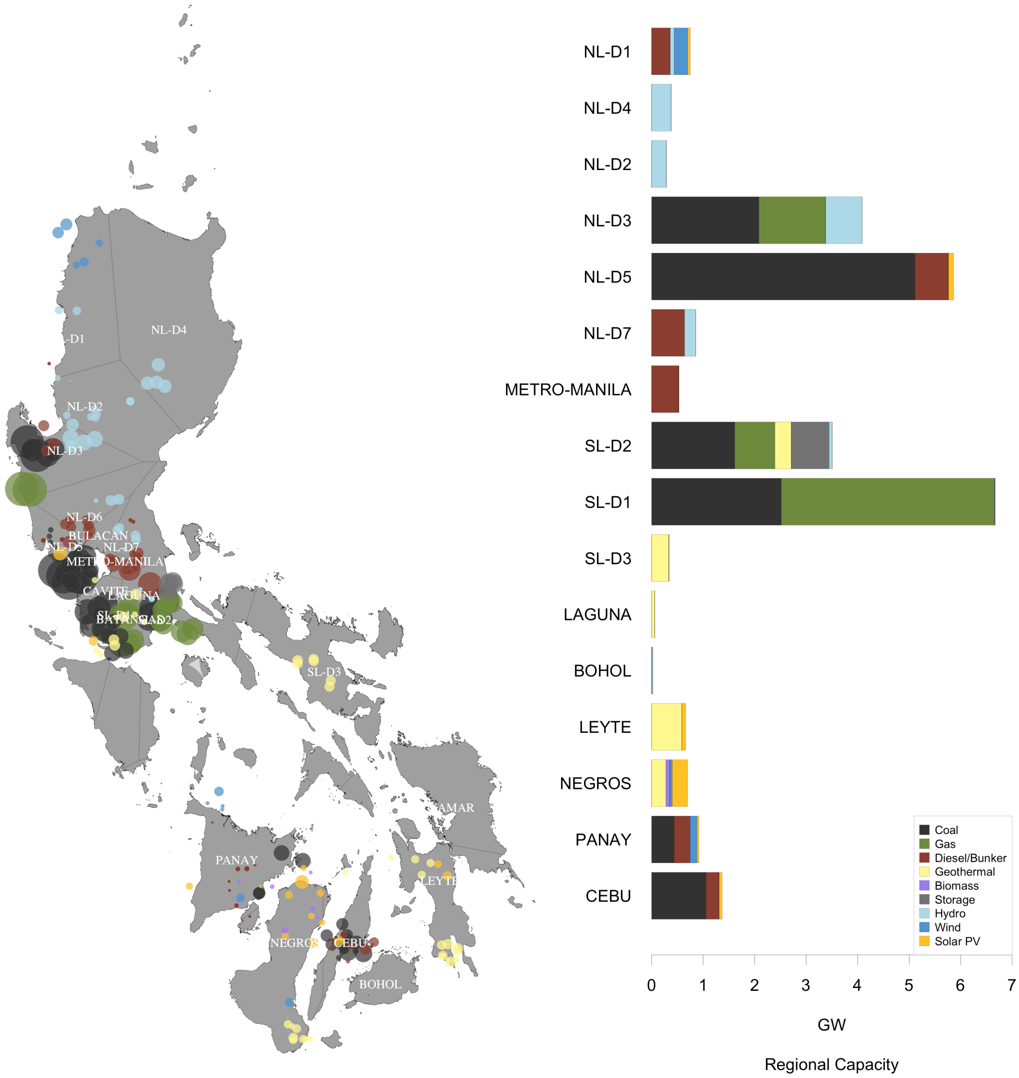


Figure 4. Approximate[8] 2030 Base Case generation locations (left) and zonal capacity totals (right).

Generation capacities and locations shown in this figure exist in all 2030 scenarios.

The four high RE scenarios include additional capacity from solar and wind above and beyond that planned in the Base Case. In these cases, solar and wind do not replace other generating capacity but rather are additional to the capacity in the Base Case. Section 3.1 describes the methodology for adding new solar and wind to the model. Figure 5 and Figure 6 show the installed capacity in each of the six core scenarios in the Luzon and Visayas systems, respectively. The estimated land use of variable RE is described in Table 4 according to the land use intensity of wind and utility-scale solar photovoltaic (PV) developments (Lopez et al. 2012).

[8] Locations indicated in Figure 4 represent the approximate node locations of selected generation resources aggregated to their respective connection nodes. Node locations shown on the map are not exact (e.g., the model contains no offshore wind).

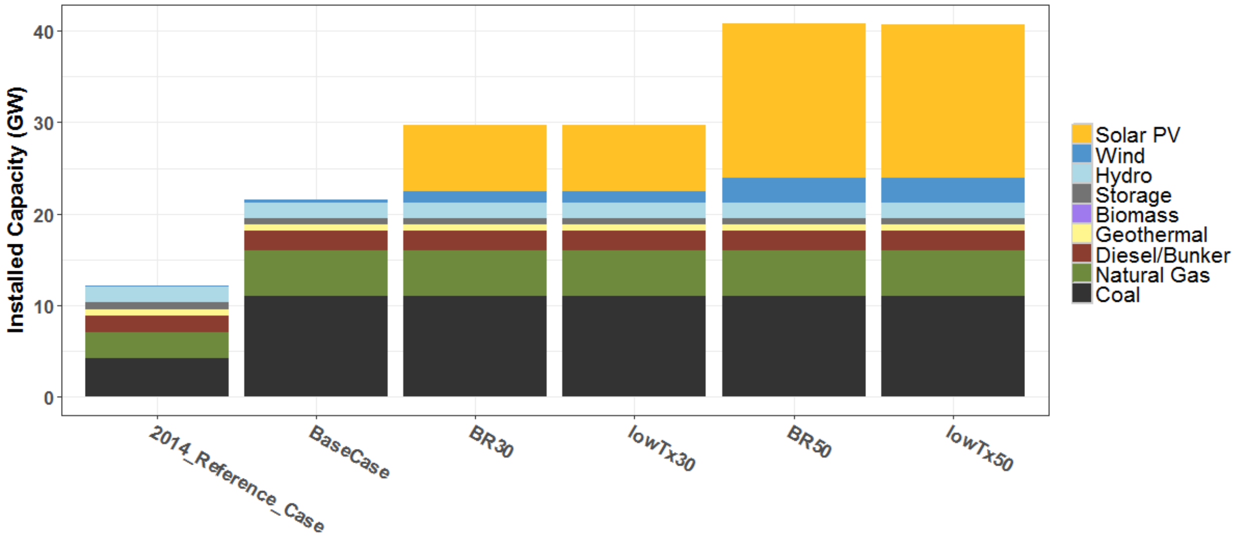


Figure 5. Installed capacity in Luzon under each scenario

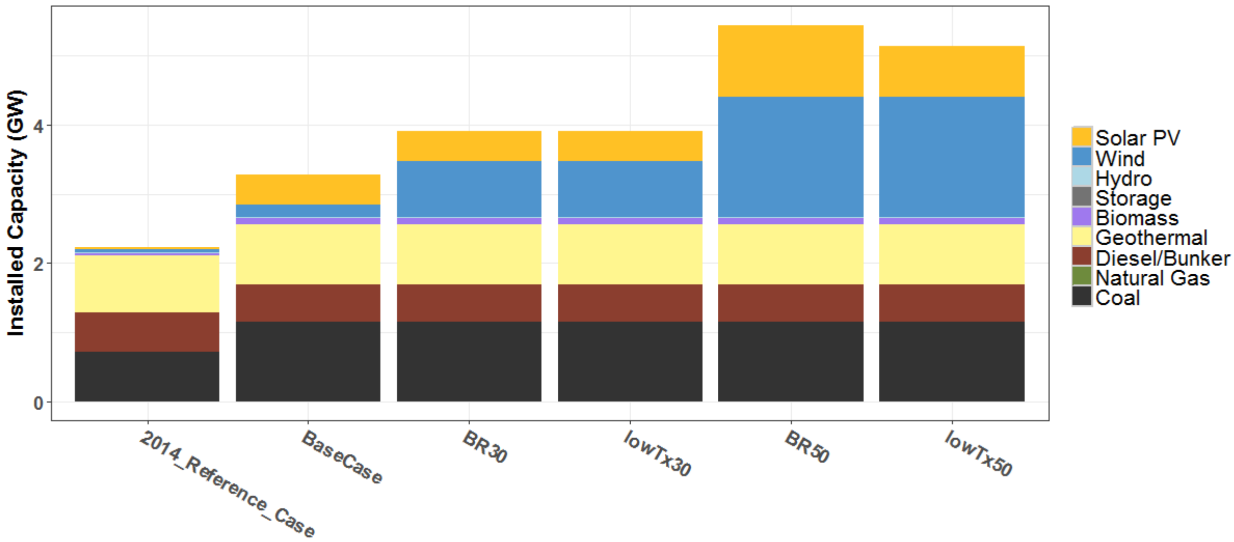


Figure 6. Installed capacity in Visayas under each scenario

Table 4. Variable RE Estimated Land Use

Scenario	Type	Installed GW	Land Use (km^2)
Base Case	Solar PV	0.5	4
Base Case	Wind	0.4	147
BR30	Solar PV	7.7	57
BR30	Wind	2.0	674
lowTx30	Solar PV	7.6	56
lowTx30	Wind	2.0	674
BR50	Solar PV	17.9	132
BR50	Wind	4.4	1,458
lowTx50	Solar PV	17.5	129
lowTx50	Wind	4.4	1,456

Generator outage rates. The MWG incorporated details regarding the frequency and duration of planned and forced generator outages. These assumptions are based on GMC-compiled equivalent forced outage rates (EFOR) and duration for coal, diesel/bunker, geothermal, hydropower, and natural gas based on 2014 operations. In addition to non-operational hours, EFOR includes hours and levels at which generators were derated. GMC converted derated hours and levels to equivalent outage hours and combined the result with standard outage rates to arrive at a value of EFOR (see Table 5). In accordance with ERC Resolution Number 17, outage rate and duration data only cover the generating plants that have an aggregate capacity of 20 MW or greater. In addition, variable RE power plants are not covered in the scope of Resolution Number 17, so the MWG has not assumed outage rates for these technologies.

Table 5. Assumed Forced Outage Rates (With Recovery Times) and Planned Outage Rates (With Maintenance Times)

Technology	Planned Outage Rate	Mean Downtime for Planned Outage [Hours (Days)]	Effective Forced Outage Rate	Mean Time to Repair Forced Outage [Hours (Days)]
Coal	5.4%	835.9 (34.8)	8.6%	58.5 (2.4)
Diesel/Bunker	2.3%	407.8 (17.0)	7.4%	105.4 (4.4)
Geothermal	1.3%	311.5 (13.0)	2.6%	33.8 (1.4)
Hydropower	10.2%	160.4 (6.7)	3.3%	33.6 (1.4)
Natural Gas (combined cycle)	2.7%	76.5 (3.2)	3.7%	268.8 (11.2)

Seasonal energy limits. Some biomass, geothermal, and hydropower units in the Luzon-Visayas system cannot consistently generate at their full capacity due to seasonal limitations in feedstock and/or water availability. To capture these limitations, the MWG applied monthly energy generation limits to biomass, geothermal, and hydropower based on actual monthly generation data from 2014 and 2015 for these resources. The 2014 Reference Case allows units of each of these fuel types to generate up to their monthly energy limit for each month of the year. In the 2030 model, the MWG scaled up the 2014 monthly energy limits proportionally to the total installed biomass, geothermal, and hydrothermal capacity in 2030, reflecting the assumption that new units are subject to the same fuel availability constraints as existing units.

2.5 Transmission Network

This study represents the Luzon Interconnection and the Visayas Interconnection as a single system connected by the underwater HVDC transmission line. The model balances nodal energy supply and demand and simulates the power flow along individual transmission elements. The modeled system has two interconnections (Luzon and Visayas) and 23 zones (including the six Visayas sub-grids), which correspond to NGCP's operations and maintenance areas (see Figure 7). Aside from delineating the reserve sharing groups (interconnections), interconnection and zone designations do not impact the model optimization (i.e., impacts are not calculated at the level of the individual sub-grid); however, they are useful for reporting purposes and for characterizing localized impacts in modeled operations. Figure 7 illustrates the designation of zones in the model.

NGCP's load flow cases for 2014 and 2030 peak load periods serve as the primary source of data for the characteristics of the existing and planned transmission networks. With these inputs, the 2030 model scenarios include approximately 1,400 nodes (buses), 960 alternating current (AC) lines (including transformers), and one direct current (DC) line interconnecting the Luzon and Visayas interconnections. The model captures the following characteristics for each node, transmission line, or transformer:

- Nodes (buses)
    - Node identification number, name, and location (zone, and, if available, latitude and longitude)
- Voltage
    - Load participation factor (see Section 2.3)
    - Transmission lines and transformers
    - Node to/from
    - Maximum and minimum real power flow ratings in the forward and backward direction
    - Resistance
    - Reactance
    - Maximum import and export on the DC line interconnecting the Luzon and Visayas grids.

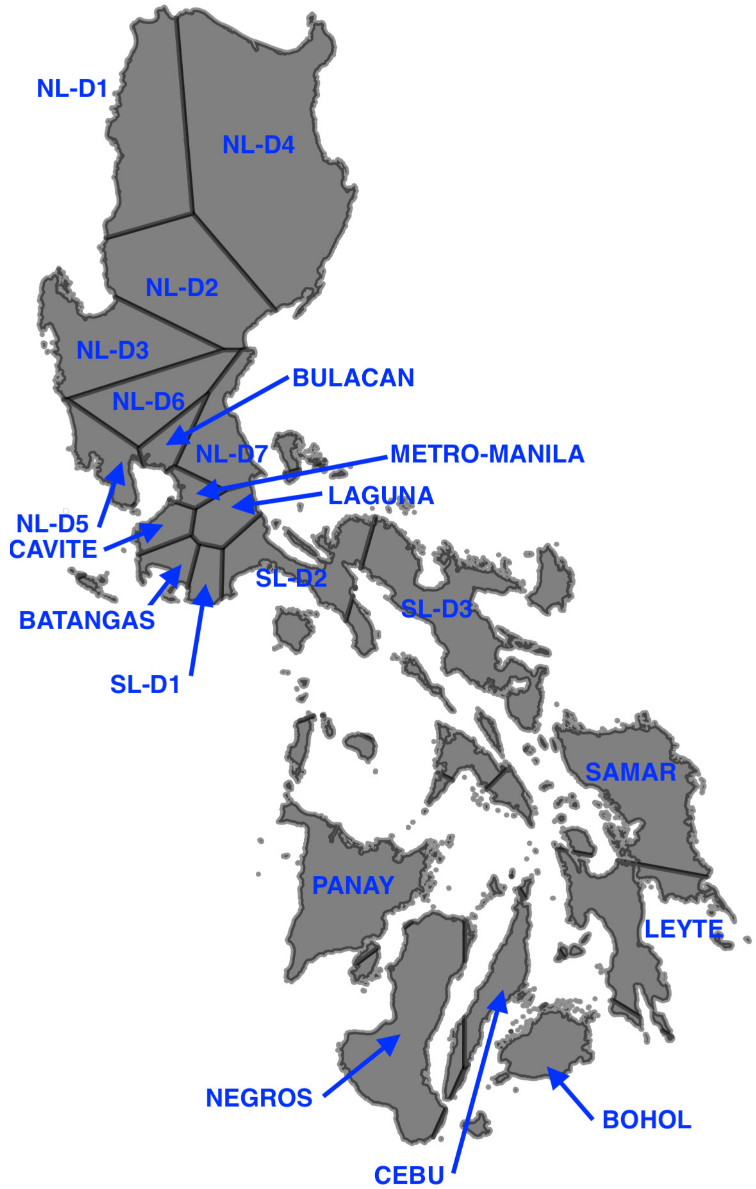


Figure 7. Zones (approximate) used in the model

The 2014 Reference Case reflects existing infrastructure and characteristics. Beyond the 2014 network, the 2030 scenarios (Base Case and all high RE scenarios) also include the major planned transmission network enhancements shown in Table 6 and numerous additions of lower-voltage and transformer enhancements. Then modeled transmission network is constant across all Base Case and high RE scenarios for 2030, with the exception of the sensitivity scenarios presented in Section 4.4.2 in which transmission line flow limits are relaxed.

Table 6. Major Transmission Network Enhancements Assumed in the 2030 Model

Luzon Interconnection	Visayas Interconnection
Alaminos - Taguig 500-kV transmission line	Batbatngon - Palo 138-kV transmission line
Bataan - Cavite 500-kV submarine cable	Cebu - Bohol 138-kV interconnection
Calaca - Dasmarinas 500-kV transmission line	Cebu – Negros - Panay 230-kV backbone
Hermosa - San Jose 500-kV transmission line	Laray 230-kV sub-station and transmission line
Mariveles - Hermosa 500-kV transmission line	Ormoc - Maasin 138-kV transmission line
Navotas - Dona Imelda 230-kV transmission line	Panay - Guimaras 138-kV interconnection
Santiago-Tuguegarao 230-kV Line 2	Panitan - Nabas 138-kV upgrading
Taguig - Tatay 230-kV transmission line	Umapad 230-kV sub-station and transmission line
Tuguegarao - Lalo 230-kV transmission line	

In order to simplify the model and reduce run-times, the MWG chose to enforce only transmission lines with voltage ratings greater than or equal to 138 kV. Analysis of model sensitivities to the 138-kV transmission voltage enforcement threshold indicated that enforcing this subset of transmission flow limits maintains reasonably accurate solutions while preserving reasonable computational run times.

This study did not include transmission line and/or transformer outage rates; however, future modeling efforts could include these additional constraints.

2.6 Reserve Rules

As part of the unit commitment optimization, the day-ahead model simulates the scheduling (i.e., holding) of different types of reserves, according to the rules defined for these reserves. The 2014 Reference Case applies the definitions and rules for three ancillary services—frequency regulating reserve, contingency reserve, and dispatchable reserve—that currently govern system operations (see Appendix A for more detail on the 2014 reserve rules). The 2030 Base Case and high RE scenarios assume a different set of reserve types (primary, secondary, and tertiary) based on the Philippine Grid Code 2016 edition (GMC 2016).[9] Table 7 summarizes the reserve rules for these projects as applied in the 2030 scenarios. In some cases, the MWG simplified these rules from those proposed because of limitations in the model capabilities (e.g., minimum primary reserve provision is proposed to be the load of the largest unit *online* in each interconnection; the MWG has modeled it instead as the load of the single largest unit in each interconnection).

[9] We use the Philippine Grid Code 2016 edition in the absence of ancillary services requirements and specifications, which prescribe detailed reserve requirements.

Table 7. Reserve Rules Assumed in the 2030 Core Scenarios

Type	Direction	Minimum Provision	Response Timeframe (Saturation)
Primary	Up	Load of the largest unit in each interconnection: Luzon: 660 MW Visayas: 170 MW	25 seconds
	Down	Half the load of the largest unit in each interconnection: Luzon: 330 MW Visayas: 85 MW	
Secondary	Up	2% of hourly demand in each interconnection	60 seconds
	Down	2% of hourly demand in each interconnection	
Tertiary	Up	4% of hourly demand in each interconnection	1 hour

The implementation of reserve definitions in the model reflects that only select generating units are qualified reserve-providing facilities (QFs), which provide ancillary services. In the Philippine power system, generating units must meet the requirements set forth in ERC's *Ancillary Services Procurement Plan* (ERC 2011) in order become QFs. Because of these stringent requirements, only those units that attained QF status in 2014 (as communicated to the MWG by NGCP) are allowed to provide reserves in the 2030 scenarios, with one exception: In the four high RE scenarios, new wind generators are allowed to provide downward reserves specifically to illustrate the utility of allowing variable RE generators to participate in reserve provision.[10]

A crucial assumption in this study is that QFs are able to respond (i.e., ramp) more quickly when they provide reserves than they when they provide energy. To reflect this assumption, the MWG specified a multiplier (i.e., a "response ratio") to the ramp rate of each QF to define the ramp rate specifically during reserve provision. The MWG defined these response ratios by dividing the maximum reserve provision from each unit by the minimum response timeframe for the associated reserve product, as established in ERC's *Ancillary Services Procurement Plan*.

This model represents electric system scheduling within a single time stage, thus the model only simulates reserve scheduling. Reserve deployment and delivery are not simulated.

2.7 Operational Costs

The production cost model optimizes day-ahead scheduling based on variable costs. As previously discussed, the scope of this study does not include evaluating or optimizing the capital costs of new generation or transmission assets. DOE provided variable fuel and operations and maintenance data based on monthly operations reports from generators in 2014. As with the other generation parameters, in cases where unit-specific data was not available, the MWG applied average costs by fuel type based

[10] While wind generators can technically provide both downward and upward reserves, we chose to allow wind generators to provide reserves but only in the downward direction for two reasons: (1) the reserve shortages present in the Base Case highlighted a need for additional reserve qualifying units; (2) due to the extreme scarcity of reserve qualifying units, allowing wind to provide upward reserves resulted in cases where virtually all wind generation was curtailed and held for reserves.

on data available for other units. Additionally, the MWG used generator start and stop costs from international sources (Lew et al. 2013) because no local data were available.

Figure 8 shows the average variable fuel and operations and maintenance costs by generator type assumed in all scenarios, including the 2014 Reference Case and the 2030 Base Case and high RE scenarios. The relative ordering of generator types determines the merit-order dispatch, which is more important to this modeling effort than the magnitude of operational costs.

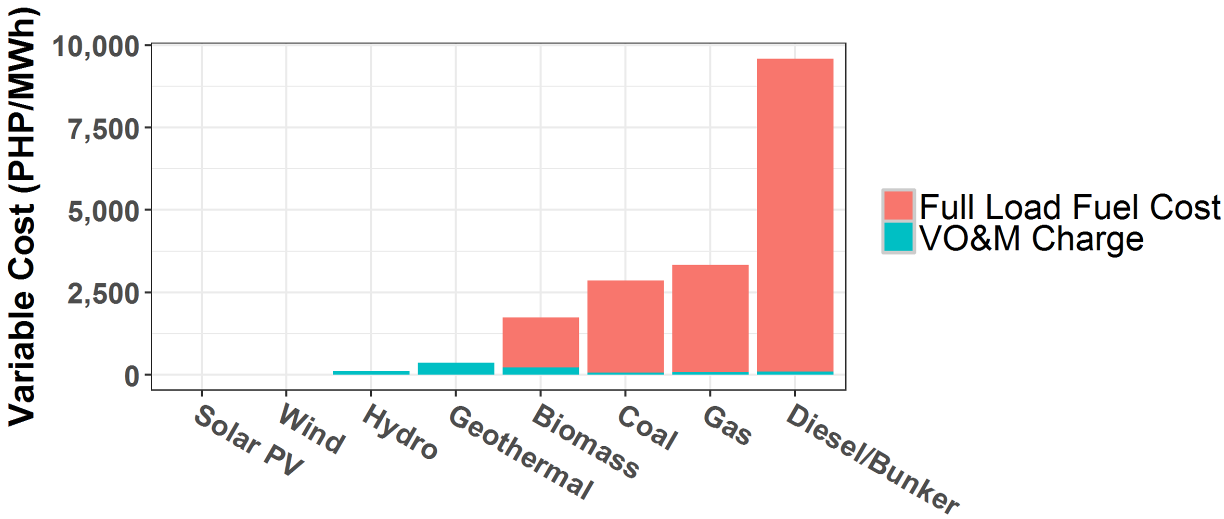


Figure 8. Average variable costs for all generator types

In addition to variable costs, the MWG also assumed the following penalty values:

- Value of lost load: 1,000,005 PHP/MW[11]
- Value of reserve shortage (all reserve products): 100,000 PHP/MW.

2.8 Emissions

The model is capable of calculating emissions from generators based on fuel-specific emissions factors and the full and partial heat rates of the generators themselves. The MWG incorporated carbon dioxide (CO_2) emissions factors for the fuels listed in Table 8. These assumptions reflect default stationary combustion emissions factors from the *2006 Intergovernmental Panel on Climate Change Guidelines for National Greenhouse Gas Inventories* (IPCC 2006).

Table 8. Carbon Dioxide Emissions Factors Assumed in the 2030 Scenarios

Fuel Type	Carbon Dioxide Emissions Rate (lb/MMBtu)
Coal	220.0
Diesel/bunker	172.4
Natural gas	130.5

Renewable fuels, including geothermal, hydro, solar, and wind, are assumed to be carbon neutral (CO_2 emissions factors equal to zero). Biomass is also considered a carbon-neutral fuel because CO_2 emissions are biogenic.

[11] PHP is the abbreviation for the Philippine peso.

3 Solar and Wind Site Selection and Net Load Analysis

To create several possible futures of the 2030 electric system, we varied the magnitude and location of wind and solar generation capacity for each of the four high RE scenarios. This wind and solar capacity is additional to the RE capacity included in the Base Case. We selected wind and solar resources with the greatest energy production potential to achieve target penetration levels. Limited by data availability and study scope, the following site selection process was adopted in lieu of a rigorous capacity expansion model in which all generation expansion options are optimized to simulate electric system evolution.[12] We also did not account for other factors critical to site selection, such as land ownership. As such, this analysis should not be treated as the sole basis for identifying the best locations for future RE installations.

3.1 Site Selection Methodology

The solar and wind site selection methodology is based on hourly weather data sets for the 2014 calendar year. The MWG used solar irradiance data produced through a mesoscale modeling effort for 30 km x 30 km grid cells.[13] The 30 km x 30 km solar resource grid cells were each decomposed into thirty-six 5 km x 5 km grid cells (each with equivalent resource data) to provide greater spatial detail for land exclusions and transmission connections. Wind resource data represent two modeled data sets—one typical meteorological weather year (TMY) data set (based on 1998–2012 data) with 1 km x 1 km grid cells and one 2014-based time series with 30 km x 30 km grid cells, both based on mesoscale modeling. The two data sets were "blended" together to create a 1 km x 1 km hourly wind resource data set for 2014 (see Appendix B for additional details).

The site selection methodology employs the following steps, which enable user-defined parameters to affect site selection.

1. **Calculate the distance between all RE sites and known transmission node locations.** Latitude and longitude data are available for approximately 200 out of the 1,400 total nodes represented in the 2030 power system. The distance between each resource grid cell (1 km^2 or 25 km^2 for wind and solar, respectively) and the nearest known node locations were calculated. The transmission network representation remains constant across all of the core 2030 scenarios.
2. **Apply geospatial filters to exclude unsuitable land for development.** The solar and wind site selection exclude the following types of land, which are unsuitable for project development:[14]
    - Slopes exceeding 5% for solar, 20% for wind
    - Water features
    - Protected areas (e.g., national parks) and a 3-km buffer around those areas for wind
    - Small land parcels (areas less than 0.03 km^2 for solar and 1 km^2 for wind)
    - Urban areas plus a 3-km buffer for wind only.

We recognize these constraints do not represent the full spectrum of technical and economic considerations that might impact the ability of a particular site to be developed (e.g., these exclusions

[12] The following data are required to construct a rigorous capacity expansion model but are outside the scope of this study to obtain location-dependent capital cost of generator and transmission construction, regional policies, and projections for fuel prices and availability.

[13] Wind and solar data representing the 2014 time series (Andresen et al. 2015) were provided courtesy of Dr. Gorm Andresen of Aarhus University in Denmark. The TMY wind data set was produced by NREL as part of USAID-sponsored technical assistance under the EC-LEDS program.

[14] The criteria for solar and wind land exclusions are adapted from similar assumptions used to evaluate technical potential for utility-scale wind and solar PV developments in the United States (see Lopez et al. 2012).

do not consider land ownership or cost, nor whether certain land-use types such as croplands may be considered for energy projects). Figure 7 and Figure 8 show the solar and wind resource maps before and after these geographic exclusions.

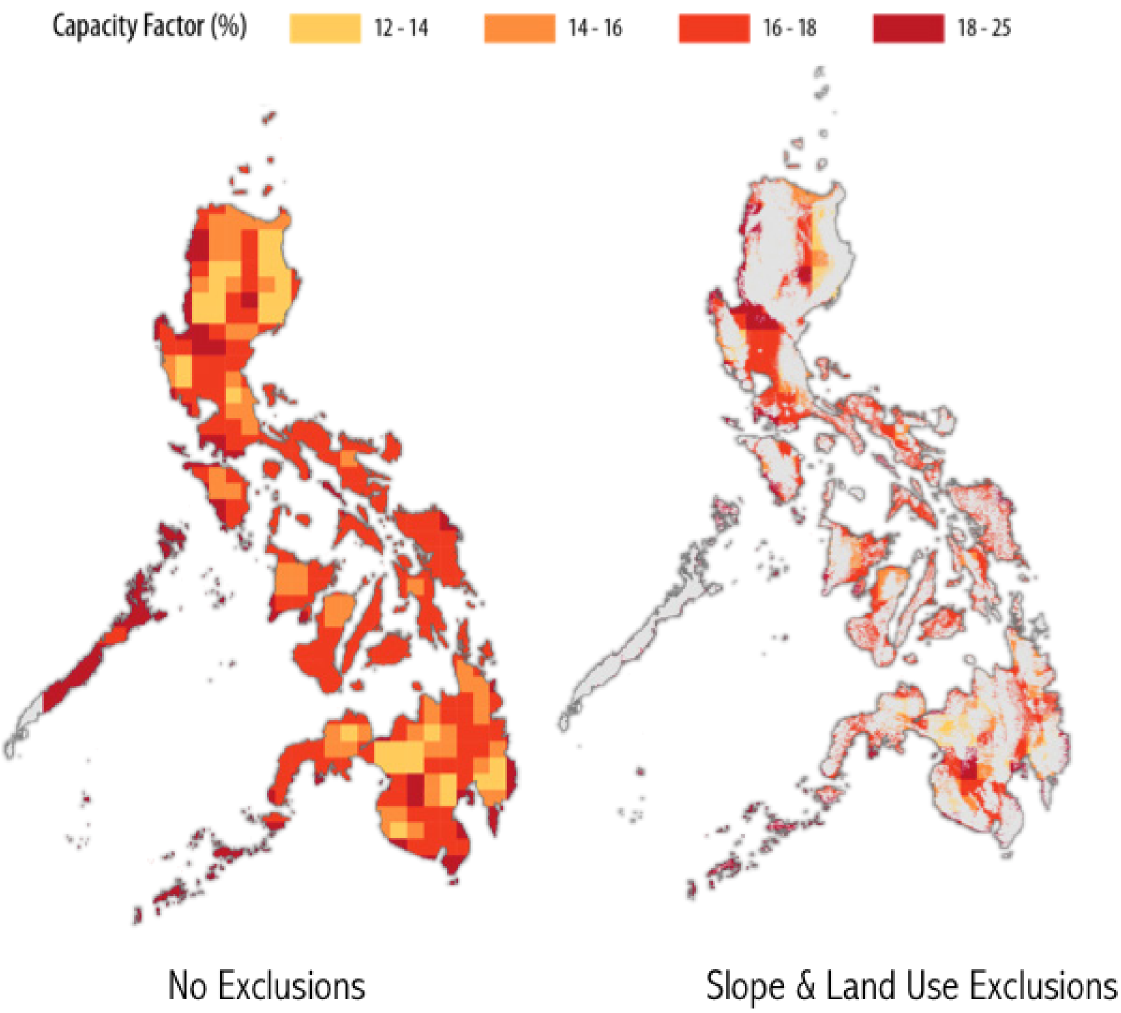


Figure 9. Geographic areas excluded from consideration for new solar generator siting

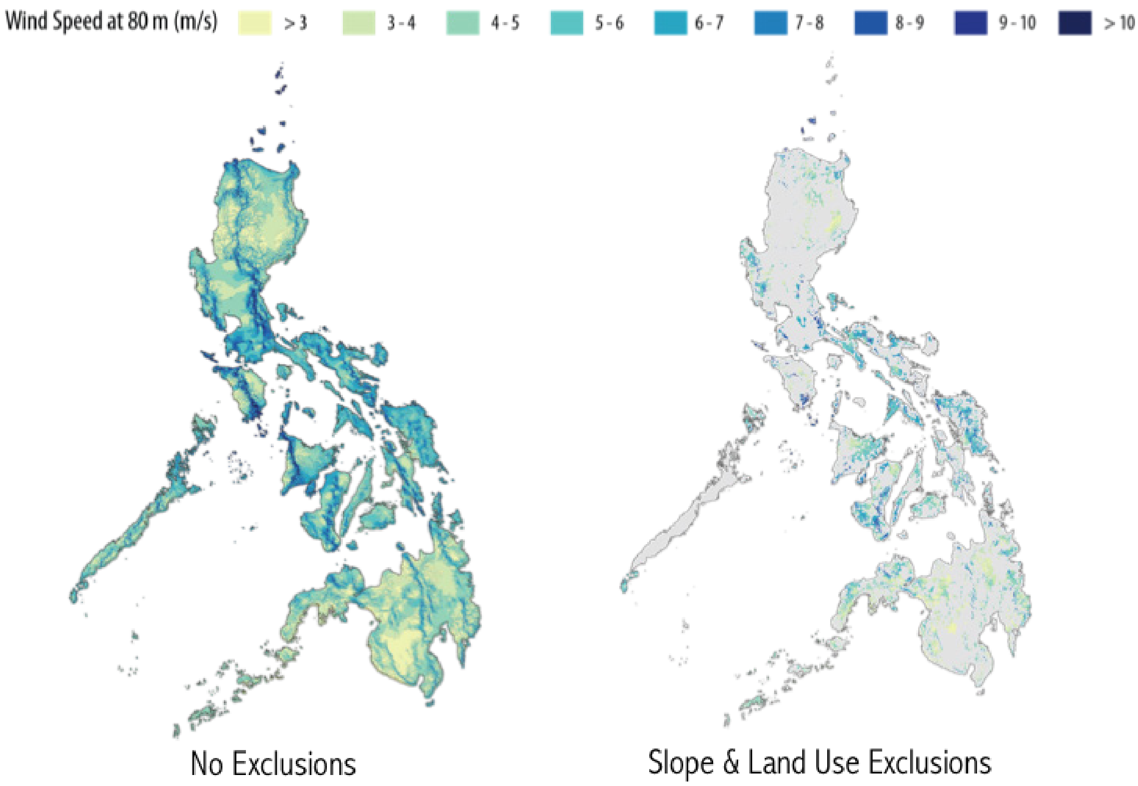


Figure 10. Geographic areas excluded from consideration for new wind generator siting

3. **Calculate annual energy production potential from RE sites.** The MWG applied several constraints to the installed capacity of solar or wind, including that solar PV and wind have a land-use intensity of 135 MW/km^2 and 3 MW/km^2, respectively. In order to avoid overly concentrated site selections, we limit the capacity selected in each 25-km^2 solar cell to 300 MW, and in each 1-km^2 wind cell to 3 MW. Ultimately, solar and wind "sites" represent any amount of capacity between zero and the installation limit (defined by cell limit or land availability, whichever is more restrictive) in each cell.[15]

Finally, the MWG applied limits on the amount of solar and wind capacity that can be developed in each zone (see Section 2.5 and Figure 7 for an overview of zones). These "zonal limits" are represented as a numeric multiplier to the peak zonal load and depend on the high RE scenario:

- ***Best Resource (BR) scenarios***: Maximum installed solar and wind capacity is capped at *four times the peak zonal load* for each zone in Luzon and *two times the peak zonal load* for each zone in Visayas to ensure sufficient geographic distribution. The TAC determined these limits during its second meeting.
- ***Minimize Transmission Impacts (lowTx) scenarios***: Maximum installed solar and wind capacity is capped on a zone-specific basis at a level that attempts to minimize zonal solar and wind curtailment to less than 10%. The iterative process for setting these limits is described in Section 3.2.

After applying all of these constraints, the resource data (e.g., solar irradiance, wind speed, and other weather data) were converted to theoretical power output based on assumptions about solar PV and wind energy generation technologies. For solar, the MWG assumed PV panels with fixed-axis tilt. For wind, the MWG assumed turbines with an 80-m hub height. Both of these assumptions

[15] In practice, the site selection algorithm selects sites with capacities equal to the cell limit for all sites except those on the margin.

reflect modern, commercially available technologies. Based on the power profiles, each solar or wind site was associated with an annual capacity factor.

4. **Sort RE sites by capacity factor and select the highest capacity sites until the target penetration levels are met.**
   We ranked cells from highest to lowest annual capacity factor and selected the highest-capacity-factor solar and wind sites until the 30% or 50% RE penetration targets, depending on the scenario, were met (penetration targets of 30% and 50% are calculated based on available energy of selected resources, assuming no curtailment). Based on feedback from the TAC and DOE's Renewable Energy Management Bureau, we imposed a rule that new solar and wind capacity should be selected such that 60% is solar and 40% is wind.

5. **Aggregate individual site wind and solar power profiles to the nearest-known substation location.**
   The aggregated solar and wind capacity and hourly profile for each node is inserted as a "generator" for modeling in the production cost model.

Figure 11 summarizes the data and calculations used to determine the locations and levels at which to integrate wind and solar capacity into the production cost model. The control parameters are outlined in Table 9, along with the values used to generate the four different site selections used in each high RE scenario.

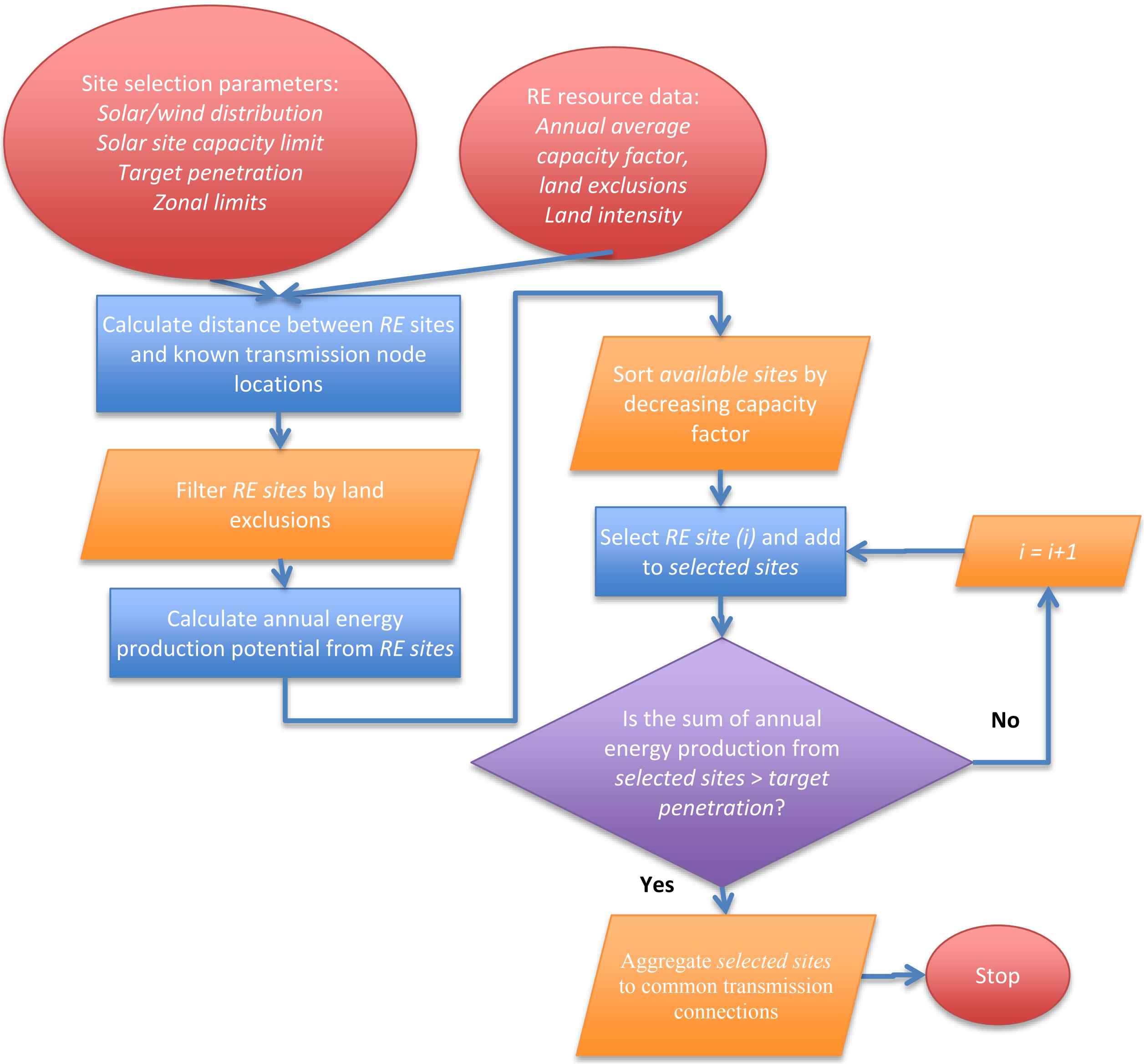


Figure 11. Site selection process flow diagram

Table 9. Site Selection Parameter Values for Each Site Selection Scenario

Parameter	Description	BR30	lowTx30	BR50	lowTx50
Solar/wind distribution	Distribution of solar and wind capacity chosen	60% 40%			
Solar/wind land-use intensity	The land area required to develop solar/wind technologies	135 W/m^2 3 W/m^2			
Solar site capacity limit	Maximum capacity for each solar resource cell (25 km^2)	300 MW			
Target penetration	Process completion threshold = (annual energy potential of selected sites)/(annual Luzon-Visayas demand)	30%		50%	
Zonal limits	Initial limit of total RE capacity selected in each zone (see Figure 7) as a multiplier on peak zonal load	2x in Visayas, 4x in Luzon	50x [a]	2x in Visayas, 4x in Luzon	50x [a]

[a] Denotes initial parameter values for iterative lowTx site selections.

3.2 Site Selection Results

In addition to refining the assumptions for each site selection process, the TAC gave guidance on the approach to differentiate between BR and lowTx site selection scenarios. The purpose of the BR scenarios is to select the highest capacity factor resources, regardless of infrastructure's capability to accommodate the capacity.[16] Both the BR30 and BR50 site selections use zonal limits of four times the peak zonal load in Luzon and two times the peak zonal load in Visayas. The site selection process for the BR scenarios involved multiple iterations through the process, described in Figure 11, to achieve final RE penetrations near 30% and 50% after curtailment. The results of the BR30 and BR50 site selections are displayed in Figure 12 and Figure 13, respectively. The zonal limits and capacity selected in each zone and scenario are summarized Appendix C.

[16] The zonal peak load capacity limits summarized in Table 9 serve to diversify selected RE site locations. Without any zonal limits, the site selection process only selects sites in a single zone to achieve the target capacity. Additionally, the initial zonal limit of 50x allows for a relaxed initial condition for the process described in Figure 14.

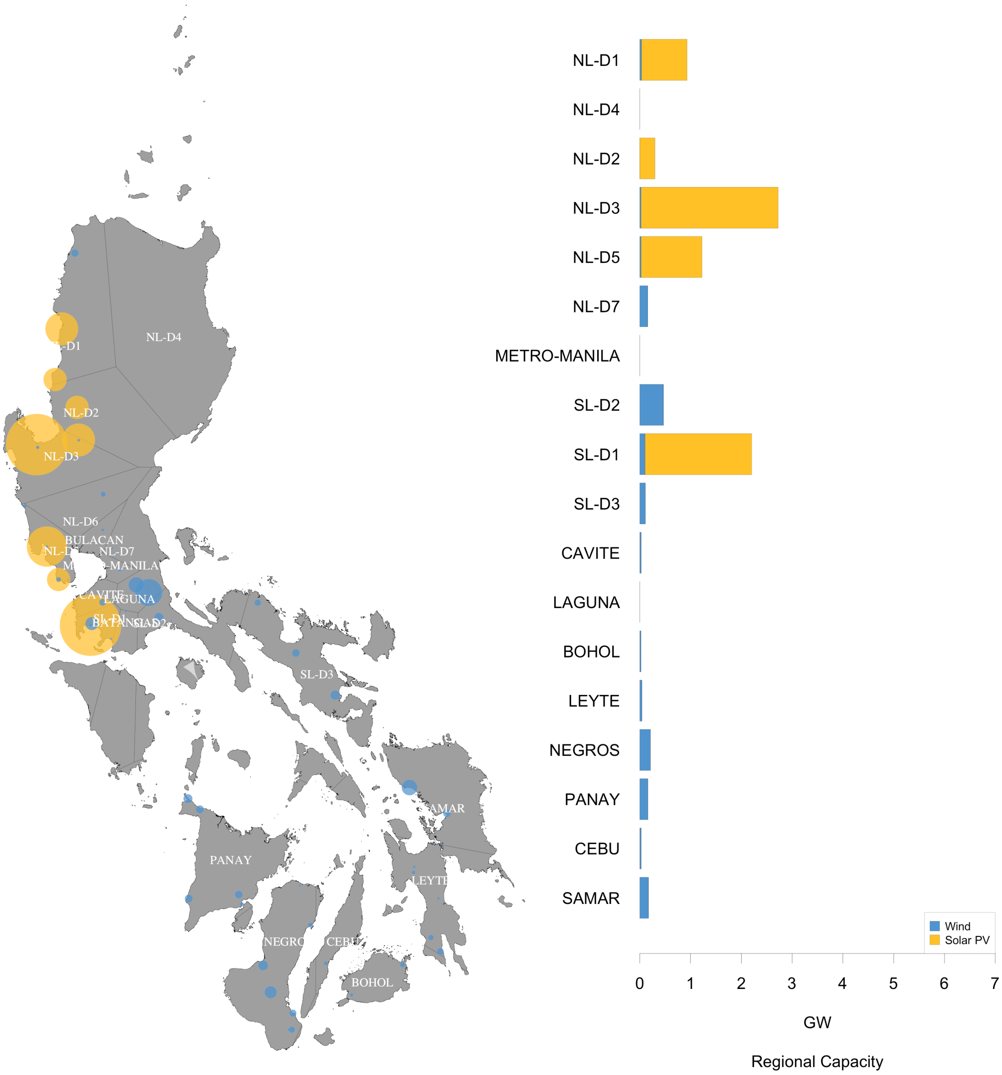


Figure 12. Approximate[17] BR30 selected wind and solar site locations (left) and zonal capacity totals (right).

Solar and wind capacities and locations shown in this figure do not include the Base Case solar and wind installations, which are shown in Figure 4.

[17] Locations indicated in Figure 12, Figure 13, Figure 15, and Figure 16 represent the approximate node locations of selected wind and solar resources aggregated to their respective connection nodes.

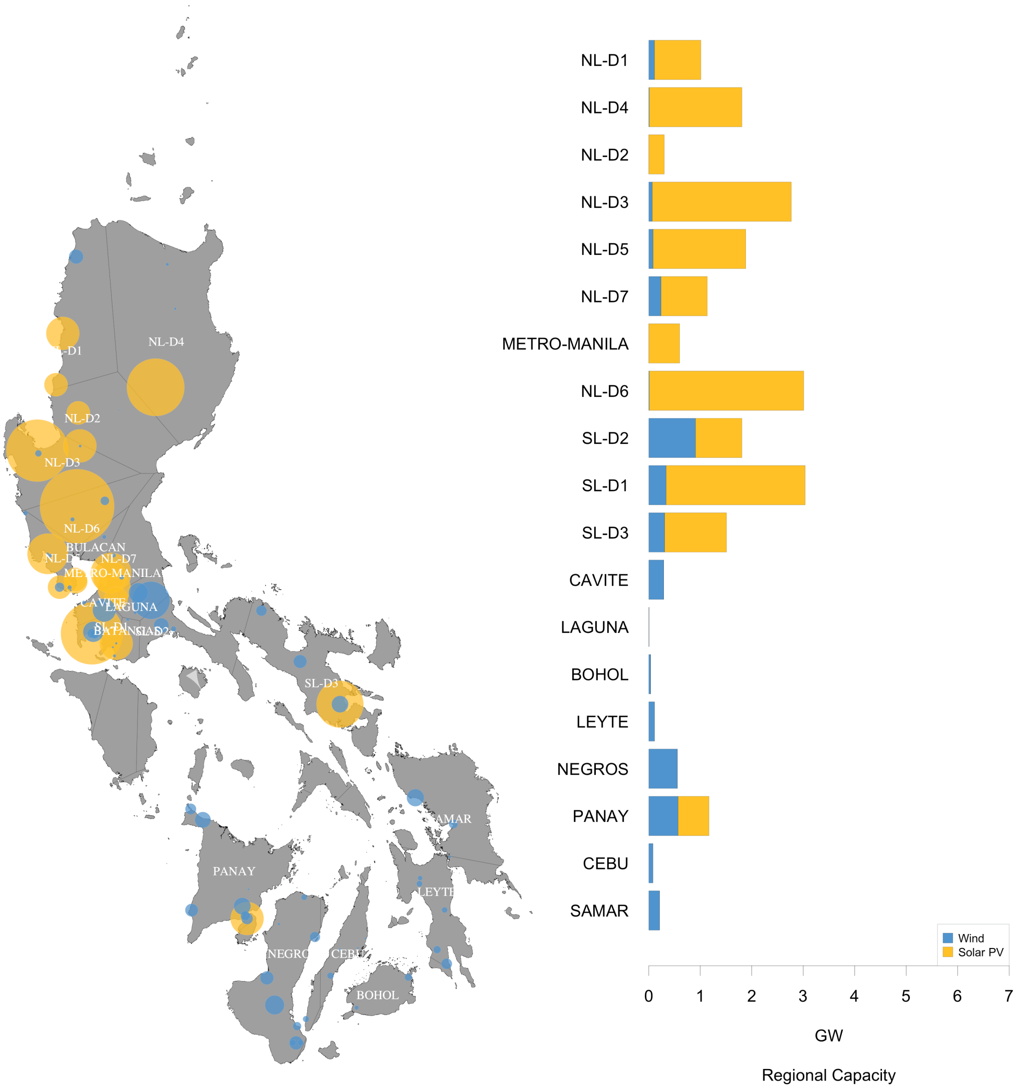


Figure 13. Approximate BR50 selected wind and solar site locations (left) and zonal capacity totals (right).

Solar and wind capacities and locations shown in this figure do not include the Base Case solar and wind installations, which are shown in Figure 4.

The purpose of the lowTx scenarios is to consider the capability of existing infrastructure when selecting RE resources. To accomplish this goal, the TAC identified an iterative site selection approach that adjusts the zonal capacity limits of the site selection process based on the relative curtailment resulting from previous site selections. The iterative site selection, shown in Figure 14, adjusts the zonal limits and target penetration parameters in the site selection process of Figure 11 to produce increasingly distributed site selection results. By simulating system operations after each site selection iteration, we are able to adjust zonal capacity limits to limit selections within zones where curtailment is above an acceptable threshold. The MWG conducted a reasonable number (3–5) of iterations to determine zonal limits for the lowTx scenarios, targeting zonal curtailment thresholds below 10% in each zone. The final lowTx30 scenario achieves this threshold in all zones. In the final lowTx50 scenarios, zonal curtailment values remain below 10%, with the exception of two zones (Panay and NL-D6). Future versions of this study could further iterate to limit curtailment in these areas.

To achieve curtailment below 10% in each zone, we initialized the iterative site selection process with zonal limits of 50 times peak zonal load in all zones. The zonal limit multipliers used in the final iteration for each scenario and the resulting site selections are summarized in the table in Appendix C.

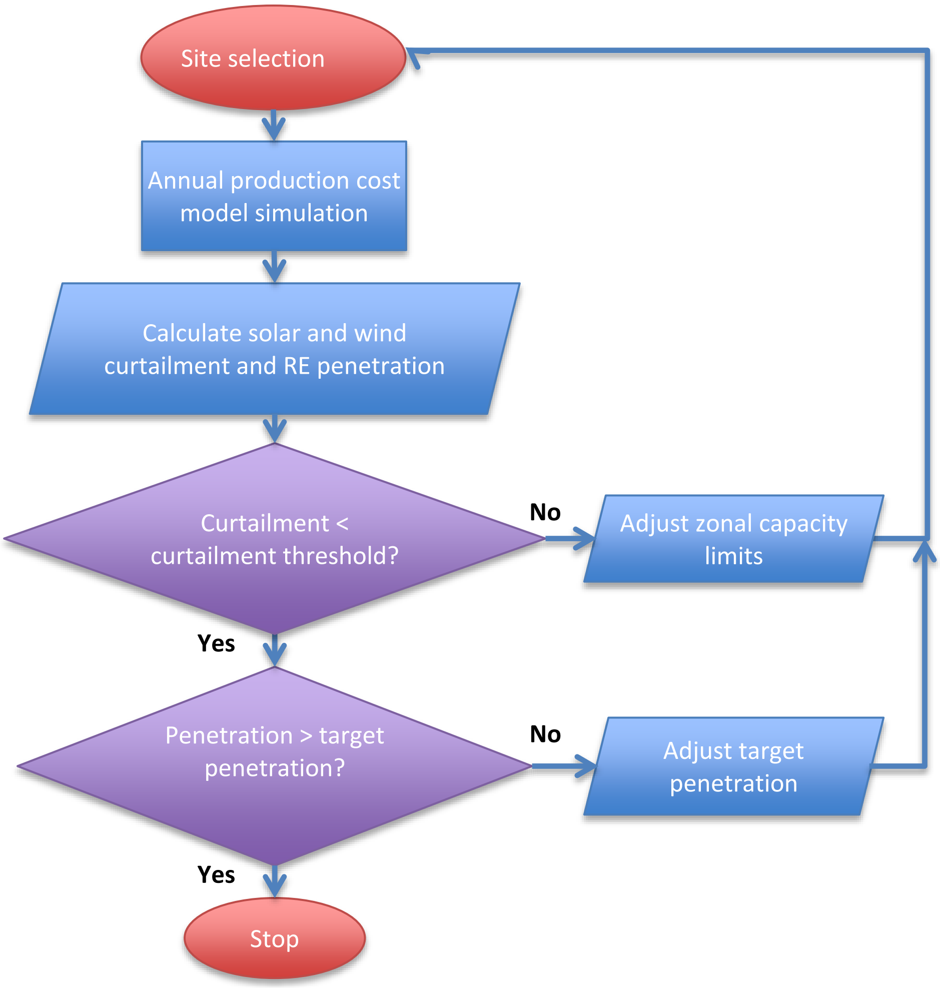


Figure 14. Iterative site selection process flow diagram used for lowTx scenarios.

Solar and wind capacities and locations shown in this figure do not include the Base Case solar and wind installations, which are shown in Figure 4.

Figure 15 shows the lowTx30 selected site locations and the total selected zonal capacities. By initiating the iterative process with relaxed zonal limits (50 times the peak zonal load), the site selection process is able to select the very best resources throughout the Luzon-Visayas system and incrementally limit selections in zones where curtailment is prevalent. For example, the iterative process identified curtailments associated with resources in the NL-D1, NL-D2, and NL-D3 zones in northern Luzon. By restricting site selections in these three zones while effectively relaxing other zone limits, the site selection process results in more concentrated site selections in zones where high-quality resources are co-located with adequate infrastructure to accommodate the RE generation.

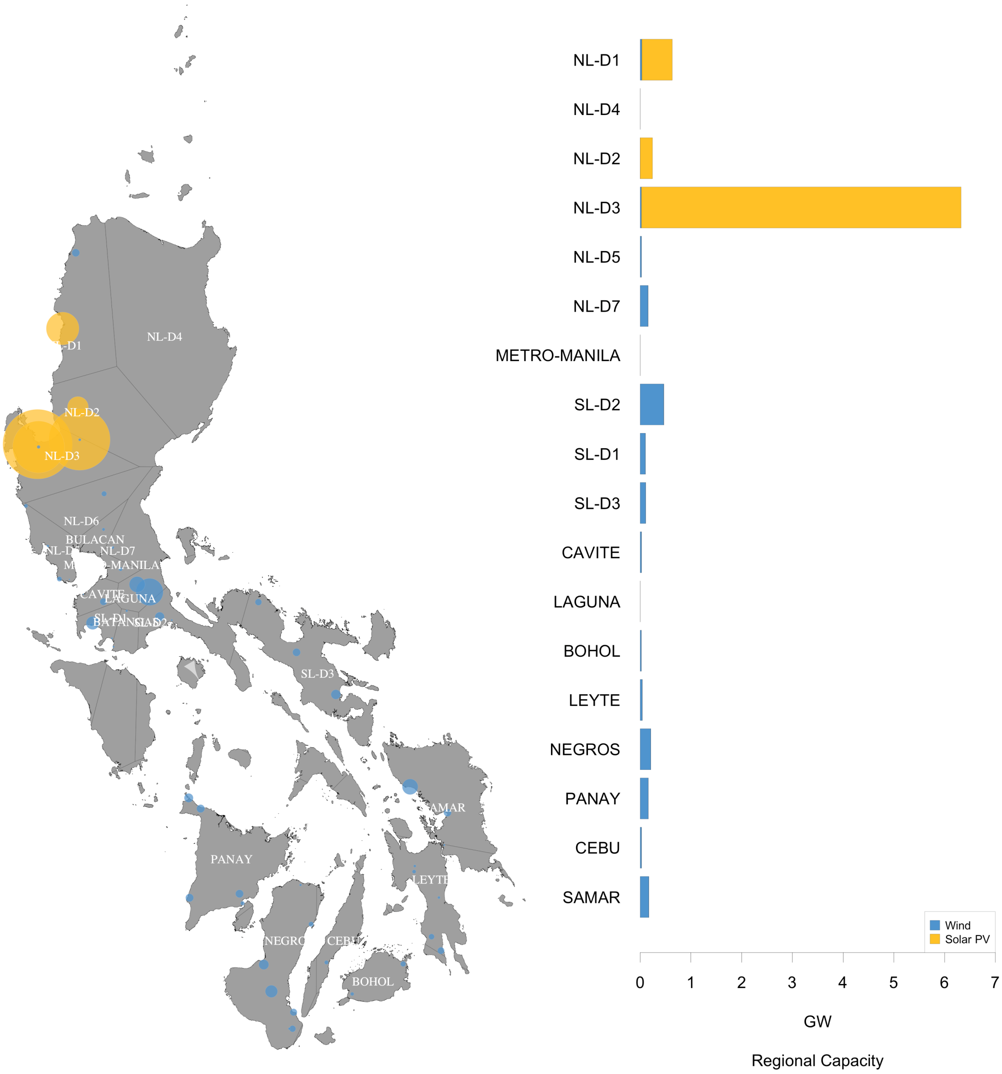


Figure 15. Approximate lowTx30 selected wind and solar site locations (left) and zonal capacity totals (right).

Solar and wind capacities and locations shown in this figure do not include the Base Case solar and wind installations, which are shown in Figure 4.

To achieve the 50% penetration level while limiting curtailment in each zone, the site selection process distributes selected RE capacity more evenly across zones relative to the lowTx30 scenario. The lowTx50 site selection is shown in Figure 16. The final zonal limits are summarized along with the three other scenarios in Appendix C. The smaller final zonal limits in several northern Luzon zones and in Panay indicate that while high capacity factor resources exist in those locations, the designed system is unable to accommodate more RE while maintaining low curtailment levels in those zones.

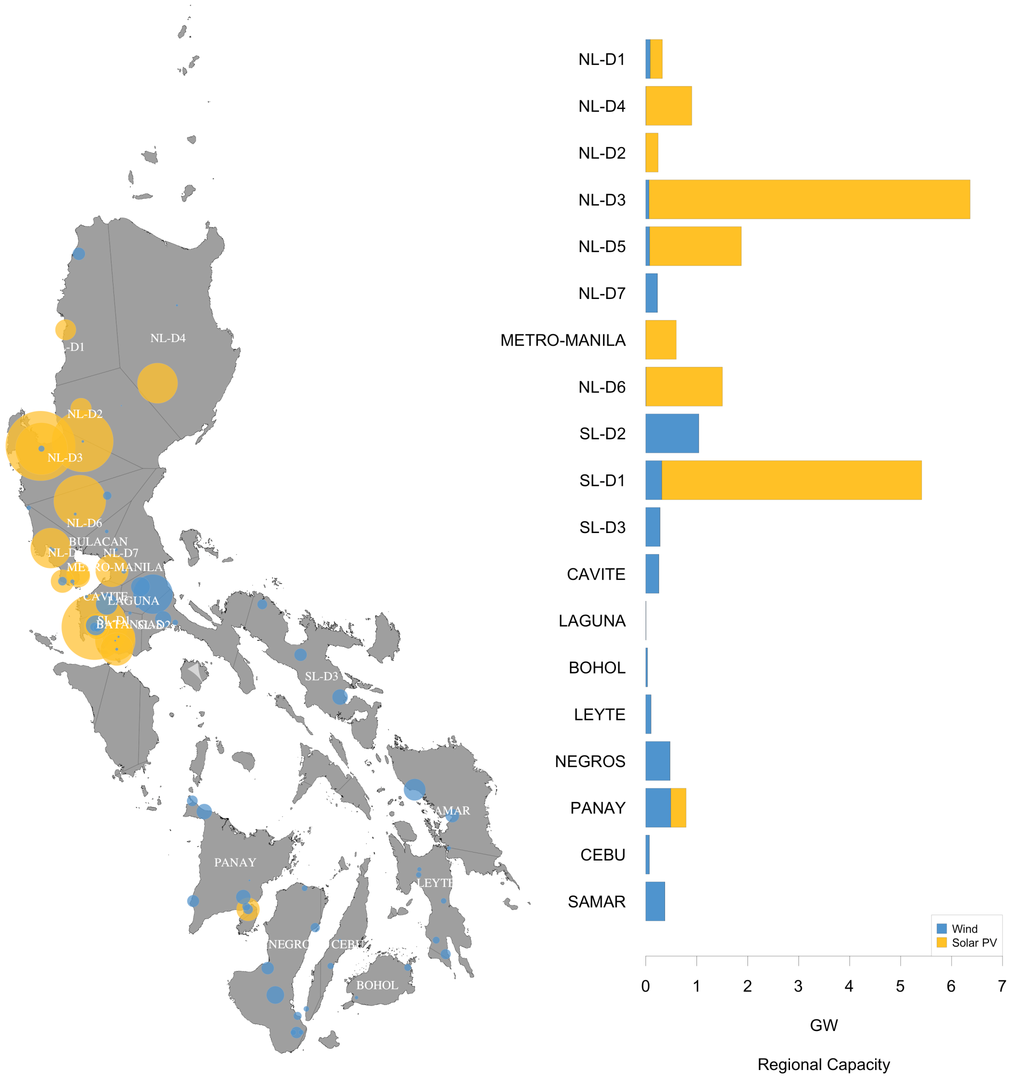


Figure 16. Approximate lowTx50 selected wind and solar site locations (left) and zonal capacity totals (right).

Solar and wind capacities and locations shown in this figure do not include the Base Case solar and wind installations, which are shown in Figure 4.

3.3 Net Load Analysis

By using time-synchronous load, solar, and wind data sets for 2014, the MWG was able to approximate the needs of the power system and to analyze a variety of impacts associated with wind and solar (e.g., evening ramps, periods of high instantaneous RE penetrations). Analyzing the interaction between the available RE generation and system load profiles can provide insight into the operational challenges that may be encountered when integrating variable RE. Because solar and wind generation is assumed to have zero marginal energy production cost (unlike conventional generation), the least cost operation will utilize as much available solar and wind generation as the system can accommodate. The remainder of demand (i.e., what the rest of the fleet must meet) is known as *net load.*[18]

Hourly Luzon-Visayas system net load, sorted in decreasing order, is shown in Figure 17 for each scenario. Comparing these net load duration curves shows the theoretical limit of coincident load that could be met by RE generation in each scenario. In Figure 17, the net load duration curves for the 30%

[18] Net load is calculated as the hourly system demand minus the hourly available energy from wind and solar generating capacity.

RE scenarios (lowTx30 and BR30) are shifted fairly uniformly downward from the Base Case and are indistinguishable from each other. Despite the differences between the BR30 and lowTx30 selected sites, the profiles for the selected resources in the two scenarios are virtually identical. This similarity is due in part to the high solar to wind capacity selection ratio (60% solar, 40% wind). The relatively uniform downward shift from the Base Case indicates a high correlation of available generation from selected resources with system demand in the 30% scenarios. The net load duration curves for the 50% RE scenarios (lowTx50 and BR50) show small differences for roughly 25% of the year. With the additional RE generation available in the 50% scenarios, the curves are further shifted downward. For a few hours of the year, net load approaches zero. However, the downward shift is not as uniform, suggesting that the available generation from selected resources in the 50% scenarios is not as consistent, relative to system load, as it is in the 30% scenarios. This is partially due to the selection of slightly lower quality resources in the 50% scenarios.

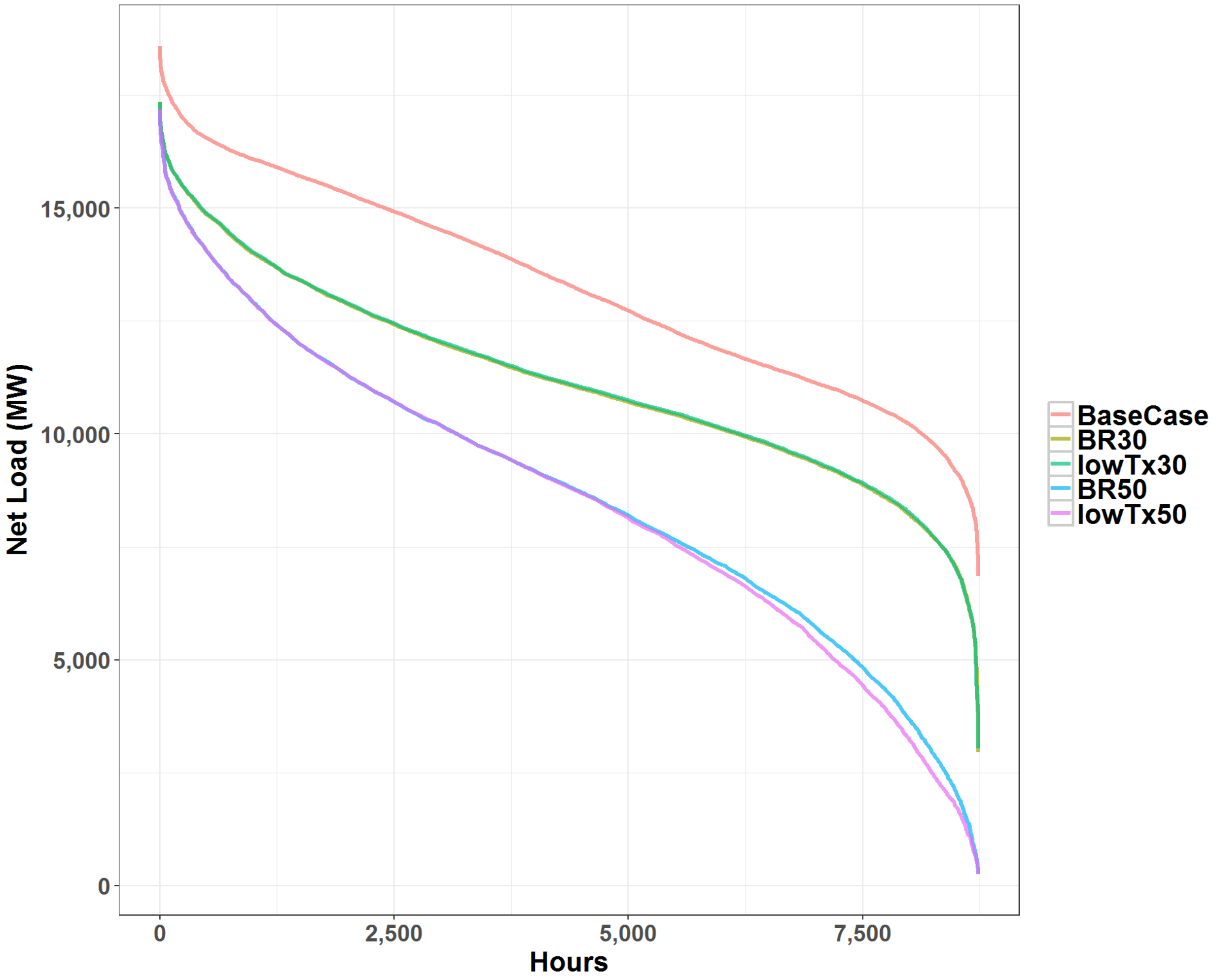


Figure 17. Luzon-Visayas net load duration curve

The duration curves in Figure 17 demonstrate how integrating variable RE resources changes the magnitudes of hourly net load values. To further understand the potential impacts of the four RE site selections, we analyze the net load variations resulting from each site selection scenario. Figure 18 and

Figure 19 show duration curves for the hourly and daily variation in net load, respectively. Again, the BR30 and lowTx30 curves on both the hourly and daily figures are virtually indistinguishable. Additionally, the hourly net load variations (i.e., hourly net load ramps) are relatively similar between the Base Case and 30% RE scenarios. The hourly net load variation similarity suggests that achieving

30% RE penetration is not likely to require significantly more hourly[19] ramping capabilities than the Base Case. Hourly net load variations are also relatively similar between the BR50 and lowTx50 scenarios. Extreme hourly variations are more prevalent in the 50% RE scenarios, suggesting that the system will rely upon more conventional generator ramping in the 50% scenarios than in the 30% RE and Base Case scenarios.

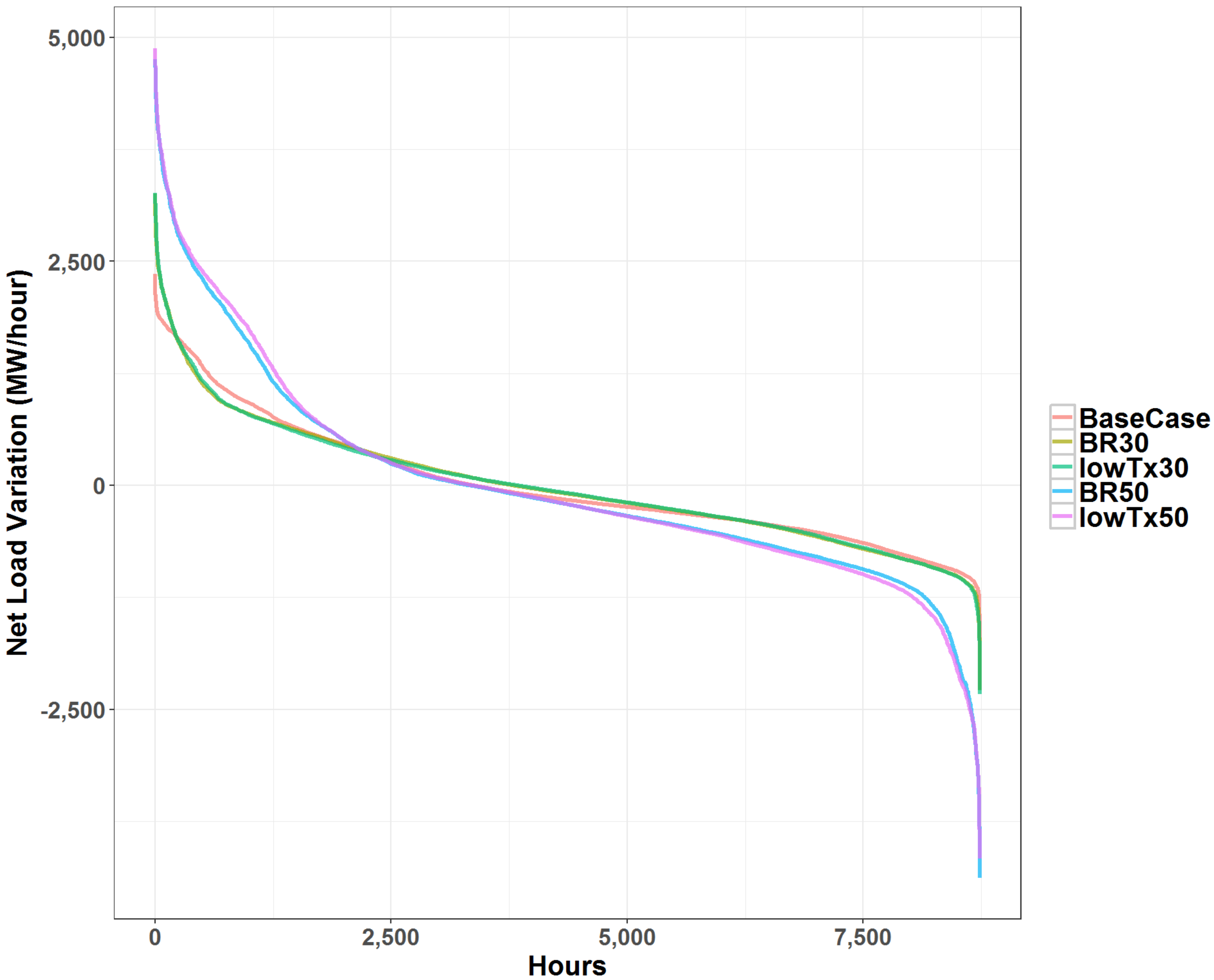


Figure 18. Luzon-Visayas net load ramp rate duration curve

Daily net load variations—the difference between the minimum and maximum hourly load in any single day—are again very similar between the Base Case, lowTx30, and BR30 scenarios, though in this case, the 30% RE cases exhibit a slightly higher daily net load variation for most hours of the year than the Base Case. The extreme increase in daily net load variation in the 50% scenarios suggests that the system will need to cycle conventional units more often to achieve 50% penetration levels. The daily net load variation difference between the BR50 and lowTx50 scenarios is more pronounced than in the other net load metrics. These daily net load variation discrepancies result from the different site selection processes employed for the BR50 and lowTx50 scenarios. The BR50 site selection favors sites with the greatest energy production potential. The lowTx50 scenario considers the deliverability of generation from RE resources in the site selection process. This tradeoff results in slightly lower correlation between the lowTx50 selected site energy profiles and system load, increasing the daily net load variability.

[19] Power system flexibility concerns often arise on timescales shorter than an hour. The hourly net load variability analysis presented here does not capture sub-hourly impacts of variable RE integration. Further analysis of sub-hourly wind, solar, and load data is required to address concerns of sub-hourly net load variability.

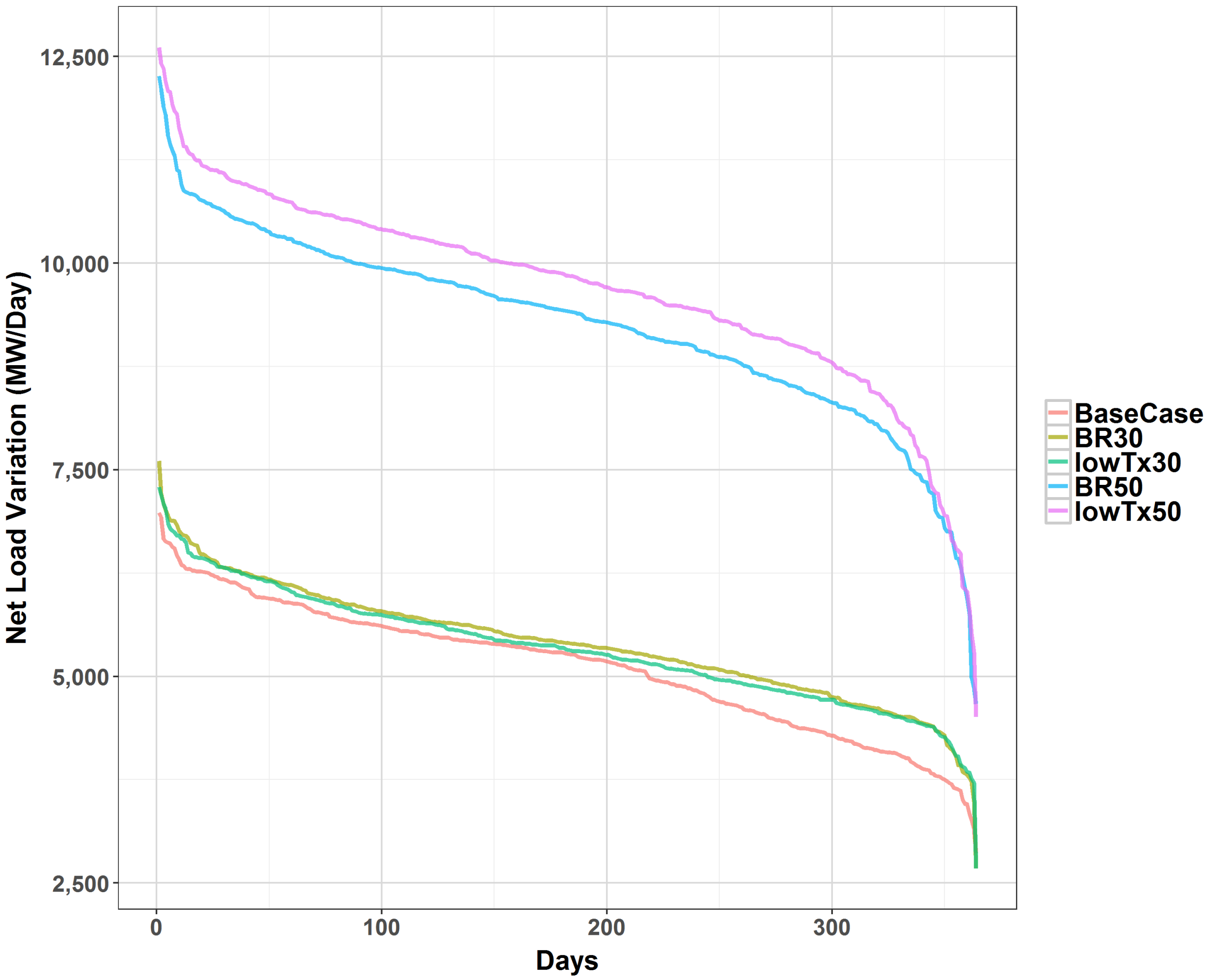


Figure 19. Luzon-Visayas net load daily swing

4 Luzon-Visayas System Operational Impacts and Modeling Results

This section presents results and analysis of the production cost model simulation of hourly system operations for the 2030 scenarios to gain insight into Luzon-Visayas system operations under greater renewable penetrations. We apply a variety of metrics across study scenarios to describe operational changes and potential challenges under different future system RE penetrations. In particular, we analyze the occurrence of solar and wind energy curtailment, which is zero-cost energy that the system is unable to use. We calculate curtailment by subtracting solar and wind energy generation from available solar and wind energy over a particular period (in most of the examples below, hourly curtailment is summed over the year). Percent curtailment equals curtailment divided by total available solar and wind energy.

Curtailment can occur because of physical or economic causes—physical, for example, when there is an oversupply of RE relative to demand or transmission availability, and economic, for example, if curtailing RE (and using coal instead) is less expensive to the system than alternatives because of the costs of shutting down and starting up coal plants. Curtailment therefore can reflect limitations to system flexibility that impede the utilization of zero-cost energy. For example, a more flexible thermal plant might be better able to turn down or off when its supply is not of value to the system. Throughout this section, we use the concepts of curtailment and system flexibility to describe the ability of the planned Luzon-Visayas system to rely upon greater amounts of wind and solar energy. Additionally, we analyze curtailment to indicate where system enhancements could be valuable. However, in all scenarios, curtailment is a tool that the operator can use strategically to improve power system flexibility and, hence, does not need to be eliminated entirely for successful integration.

4.1 How Do Wind and Solar Contribute to Total System Generation and Balancing?

4.1.1 *Contribution of RE to Annual Generation*

This study finds no technical barriers to balancing hourly supply and demand with high RE penetration, assuming the planned system evolution (i.e., addition of new transmission and generation) described in Section 2. Hourly balancing is achievable under all of the 30% and 50% RE scenario study assumptions. Figure 5 and Table 10 show the annual generation by generator type in the Luzon-Visayas system for each 2030 scenario. The Base Case demonstrates a modest RE penetration (15%), comprised primarily of geothermal and hydro generation. The four high RE scenarios achieve between 31% and 50% total RE penetration by increasing the amount of wind and solar capacity modeled in 2030.

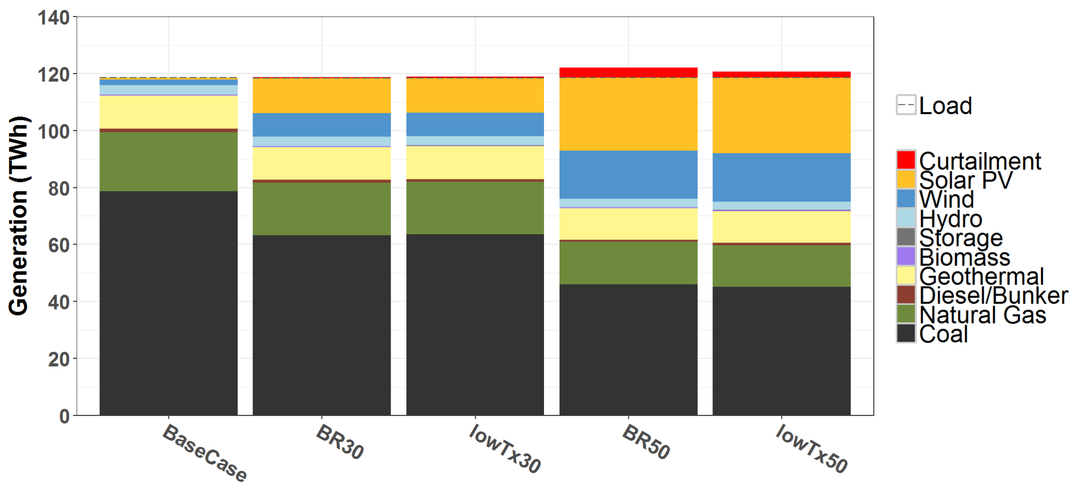


Figure 20. Annual Luzon-Visayas system generation by generator type across all five 2030 scenarios

Table 10. Total and Relative Generation by Scenario and Type

	Coal	Diesel/ Bunker	Gas	Biomass	Geothermal	Hydro	Storage	Solar PV	Wind	Curtailment	Total RE	Total[a]
GWh												
Base Case	78,600	1,245	20,872	288	11,550	3,359	66	705	1,812	–	17,715	118,498
BR30	63,304	982	18,428	289	11,512	3,212	52	12,444	8,256	206	35,713	118,479
BR50	45,963	851	14,894	272	11,048	2,842	122	25,630	16,934	3,513	56,726	118,556
lowTx30	63,537	986	18,436	288	11,513	3,199	54	12,211	8,257	397	35,468	118,481
lowTx50	45,185	865	14,536	277	11,132	2,837	152	26,500	17,107	2,028	57,853	118,592
Percent												
Base Case	66.3	1.1	17.6	0.2	9.8	2.8	0.1	0.6	1.5	0.0	15.0	100.0
BR30	53.4	0.8	15.6	0.2	9.7	2.7	0.0	10.5	7.0	1.0	30.1	100.0
BR50	38.8	0.7	12.6	0.2	9.3	2.4	0.1	21.6	14.3	7.6	47.9	100.0
lowTx30	53.6	0.8	15.6	0.2	9.7	2.7	0.1	10.3	7.0	1.9	29.9	100.0
lowTx50	38.1	0.7	12.3	0.2	9.4	2.4	0.1	22.4	14.4	4.4	48.8	100.0

[a] Total annual generation differs slightly in each scenario due to differences in pump load to operate pumped-hydro storage.

4.1.2 Variable RE Curtailment

Figure 20 and Table 10 indicate that solar and wind curtailment remains under 8% in all cases and under 5% in all but one scenario, which is typically considered a reasonable amount relative to costs of reducing RE curtailment. Curtailment, denoted by the red area at the top of each stacked bar in Figure 20, represents the available zero-cost wind and solar energy that the system is unable to utilize. Curtailment in the BR30 and lowTx30 scenarios is 1.0% and 1.9%, respectively. As indicated in the net load analysis in Section 3.3, the solar and wind siting strategy impacts curtailment more significantly in the 50% RE cases, with the lowTx50 and BR50 scenario exhibiting 4.4% and 7.6% curtailment, respectively. Because the transmission network is identical in each scenario, the amount of curtailment present in each scenario is driven by the specific wind and solar sites selected for each scenario, which represent unique combinations of weather data and network availability.

Curtailment is driven in part by solar and wind generation patterns. Figure 21 shows average solar and wind percent curtailment for each hour of the day. Diurnal solar generation is an important driver; curtailment reaches its peak in the middle of the day when solar availability is at its maximum. As is the case with annual curtailment, curtailment is most significant in the BR50 scenarios, with the average hourly curtailment reaching over 16% at midday.

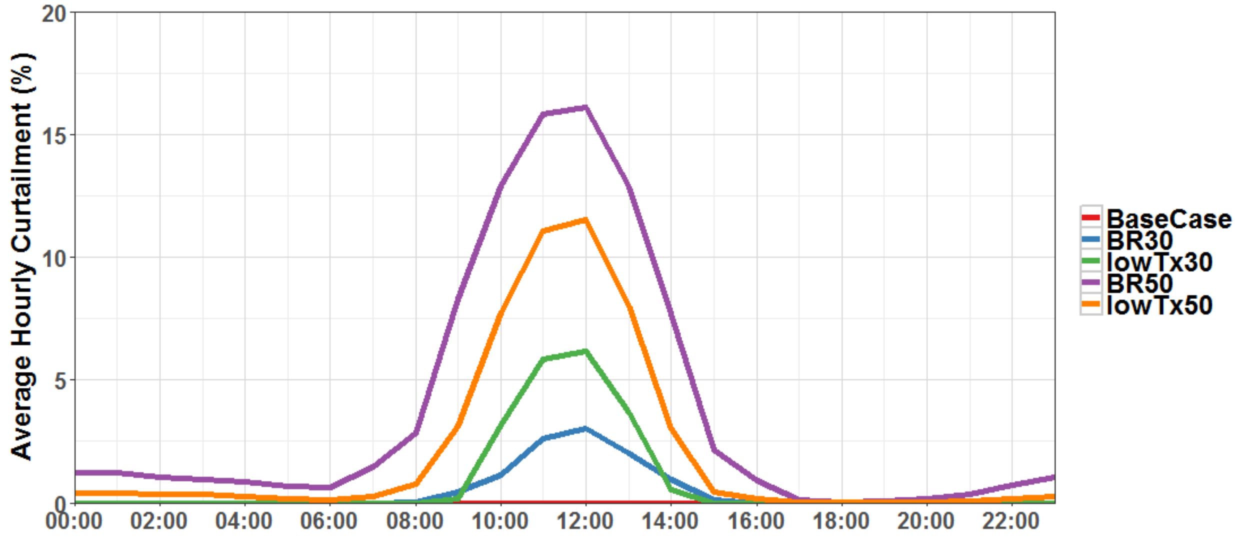


Figure 21. Average hourly solar and wind percent curtailment in all 2030 scenarios

4.1.3 Impact on Conventional Generation, Fuel Consumption, Variable Costs, and Emissions

In the 2030 scenarios, variable RE primarily displaces generation from coal and natural gas, leading to lower fuel consumption (and associated fuel costs and emissions). Figure 22 shows differences in total 2030 generation for each scenario relative to the Base Case (positive values indicate an increase in generation relative to the Base Case, while negative values indicate a decrease). The difference plot highlights the increased utilization of wind and solar and the resulting reduction in coal and natural gas generation. The increased wind and solar capacity simulated in the 30% (BR30 and lowTx30) and 50% (BR50 and lowTx50) RE scenarios predominantly displace coal and, to a lesser extent, natural gas generation. The lower marginal generation cost of coal relative to natural gas, in combination with the greater coal displacements suggests that the model requires the flexibility provided by natural gas generation. The reductions in coal and natural gas generation that result from increased variable RE capacity drive proportional reductions in fuel consumption. As shown in Table 11, solar and wind displace up to 40% of fuel consumption from diesel/bunker, natural gas, and coal generators in the lowTx50 scenario relative to the Base Case.

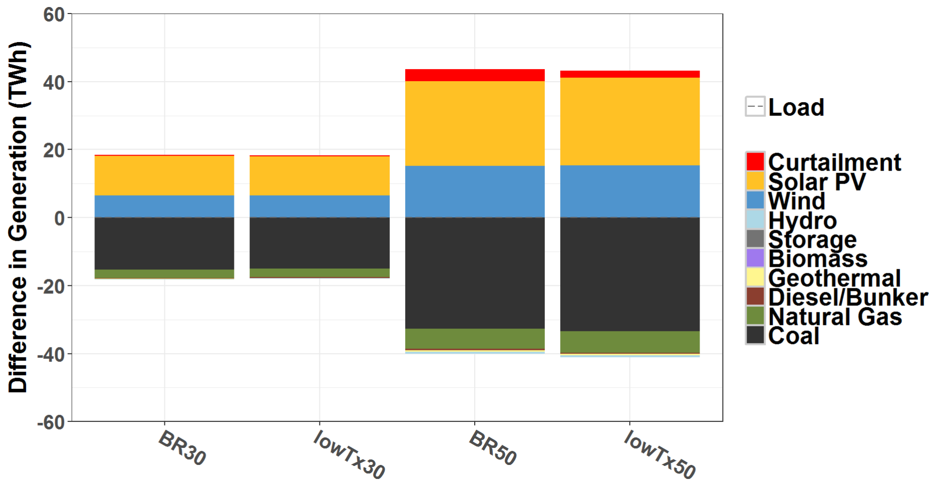


Figure 22. Annual Luzon-Visayas system generation differences by generator type relative to the Base Case

Table 11. Diesel/Bunker, Natural Gas, and Coal Fuel Consumption in MMBtu *(and Percent Difference from the Base Case)* in all 2030 Scenarios

Fuel Type	Base Case	BR30	lowTx30	BR50	lowTx50
Diesel/Bunker	20.0	18.0 (*-10%*)	18.0 (*-10%*)	16.5 (*-18%*)	16.6 (*-17%*)
Natural Gas	134.2	116.9 *(-13%)*	117.0 *(-13%)*	94.8 (*-29%*)	93.0 (*-31%*)
Coal	812.6	651.1 *(-20%)*	654.9 *(-19%)*	475.5 *(-41%)*	467.2 *(-43%)*
Total	**966.8**	**785.9 (*-19%*)**	**789.9 (*-18%*)**	**586.8 (*-39%*)**	**576.9 (*-40%*)**

Table 12 summarizes changes in annual variable costs (including fuel costs, start and shutdown costs, operations and maintenance costs, and total costs) in each high RE scenario relative to the Base Case. A negative value indicates a reduction in cost from the Base Case, while a positive value indicates an increase. These results indicate that total production costs would decrease significantly (between 17% and 37%, depending on the amount of RE and the siting strategy) in the high RE cases. This reduction in cost is primarily due to the decrease in fuel costs, which comprise 96% of total production costs in the Base Case. Thus, even though start and shutdown costs increase significantly in the high RE cases relative to the Base Case, these additional costs are more than offset by reductions in fuel costs. Note, while variable costs decrease in the high RE scenarios, capital costs increase compared to the Base Case. Evaluating capital cost differences is outside the scope of this study.

Table 12. Change in Variable Costs (in Million PHP) of Each High RE Scenario Relative to the Base Case

Variable Cost in Million PHP				
	BR30	**lowTx30**	**BR50**	**lowTx50**
Fuel	-52,300 (-18%)	-51,300 (-17%)	-110,100 (-37%)	-112,800 (-38%)
Start and shutdown	7.9 (+38%)	7.9 (+38%)	16.8 (+81%)	17.9 (+87%)
Operations and maintenance	-1,300 (-11%)	-1,300 (-11%)	-3,000 (-25%)	-3,100 (-26%)
Total	-53,700 (-17%)	-52,600 (-17%)	-113,100 (-36%)	-115,900 (-37%)

Similarly, due to the reduction in coal and natural gas consumption, **the high RE scenarios significantly reduce CO_2 emissions**. Figure 23 shows the annual Luzon-Visayas CO_2 emissions for each scenario. The 30% RE scenarios both achieve 19% reductions in CO_2 emissions relative to the Base Case, while the BR50 and lowTx50 scenarios achieve a 40% and 41% reduction, respectively. Annual emissions calculations account for the increased amount of time spent by thermal units at partial load in the high RE scenarios. However, any increase in emissions due to this less efficient operation is more than offset by emissions reductions associated with reduced fuel consumption.

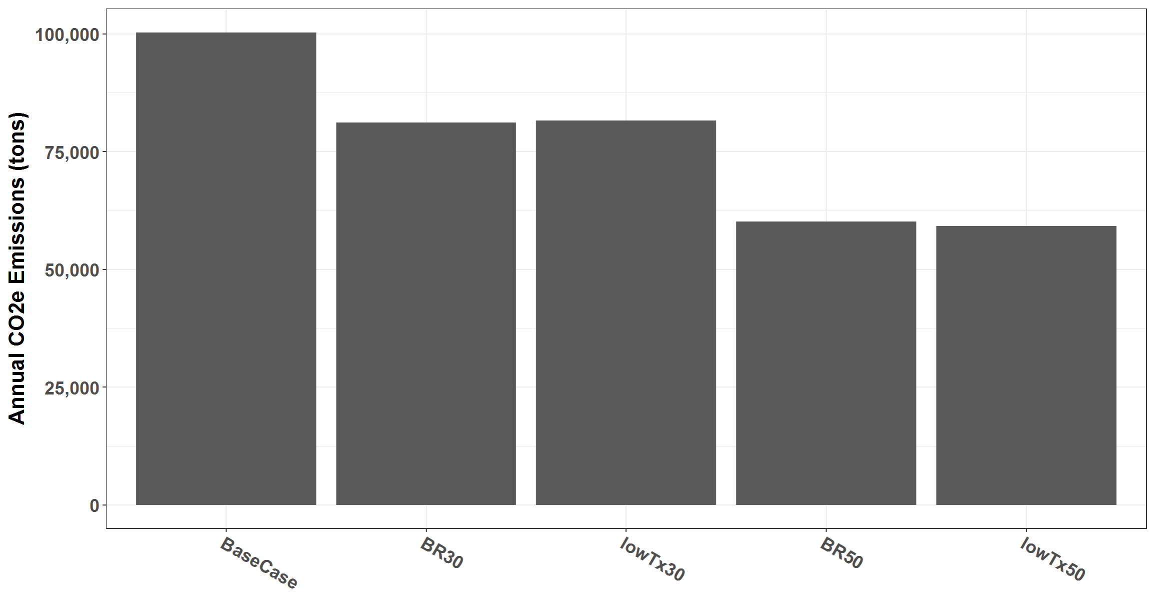


Figure 23. Annual Luzon-Visayas system CO_2 emissions

4.1.4 Instantaneous Variable RE Penetration

Hourly RE penetration will increase in all high RE scenarios. Figure 24 shows the duration curve of instantaneous variable RE (i.e., solar and wind) penetration for each scenario. Instantaneous variable RE penetration is the percent of hourly generation that is supplied by solar and wind. The variable RE penetration curves for the 30% RE scenarios are virtually indistinguishable, while the two 50% RE scenarios result in different variable RE penetrations for about 2,500 hours of the year. The differences in variable RE penetration result from a combination of the different sites selected for each scenario and the curtailment resulting from the system scheduling optimization. **The maximum instantaneous variable RE penetrations are approximately 65% and 97% for the 30% and 50% RE scenarios, respectively, while the maximum variable RE penetration for the Base Case only reaches 6.4%.** Further analysis on instantaneous penetration levels in the context of synchronous versus non-synchronous generation is presented in Section 4.5.4.

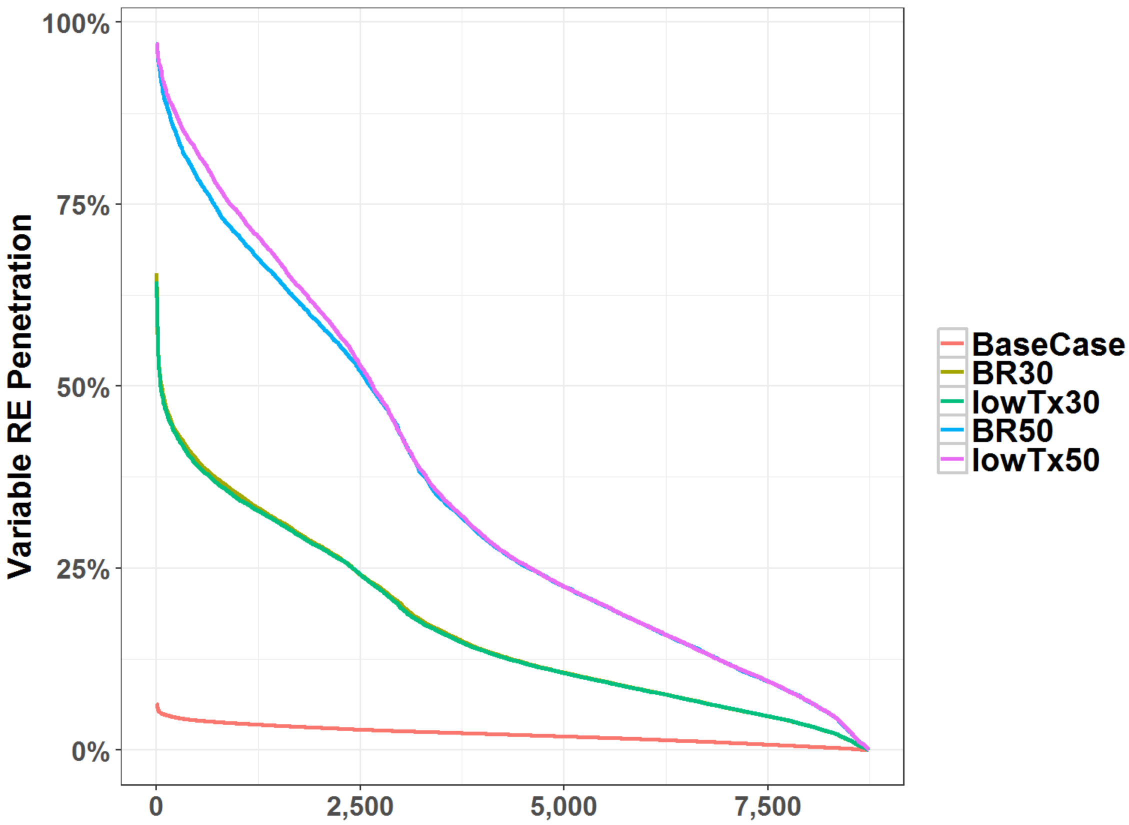


Figure 24. Luzon-Visayas system instantaneous wind and solar energy penetration duration curve

4.2 How Do Wind and Solar Differentially Affect Luzon and Visayas Interconnections?

In the high RE scenarios, generation, import, and export patterns change within the Luzon and Visayas interconnections, including Visayas becoming a net exporter to Luzon in the 50% RE penetration scenarios. Figure 25 presents the total annual generation for each of the Luzon and Visayas interconnections. The Luzon and Visayas interconnections are linked with a single HVDC underwater transmission line. In the 2014 Reference Case and in the Base Case 2030 model, the Luzon interconnection is a net exporter of energy to Visayas via the HVDC line. The difference between the dashed load line and the top of the generation stack denotes the total amount of net imports or exports for each interconnection. Under 30% RE penetrations, Figure 25 shows reductions in the annual net transfer of energy from Luzon to Visayas. The 50% RE scenarios demonstrate a direction reversal, such that Visayas becomes a net exporter to Luzon.

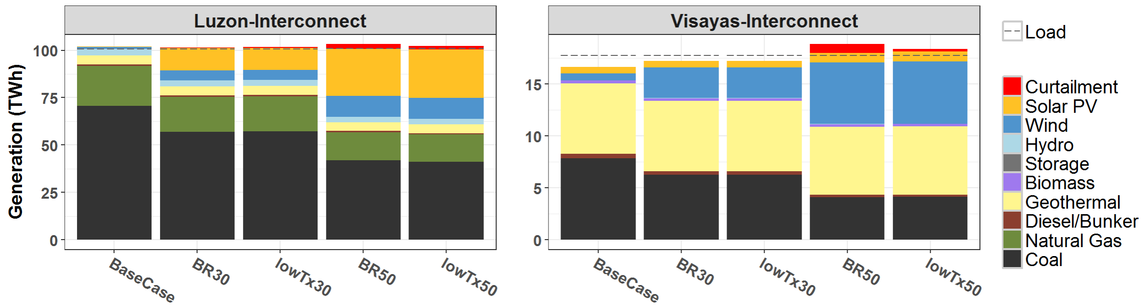


Figure 25. Annual Luzon and Visayas system generation by generator type across all five 2030 scenarios

Note: Y-axes between the left and right panels are not the same scale.

Figure 26 shows that increased wind generation is distributed relatively evenly across the two interconnections, while increased solar generation is primarily limited to Luzon. Although Visayas experiences small reductions in coal generation as RE penetration increases, the majority of coal and gas generation displacements occur in Luzon.

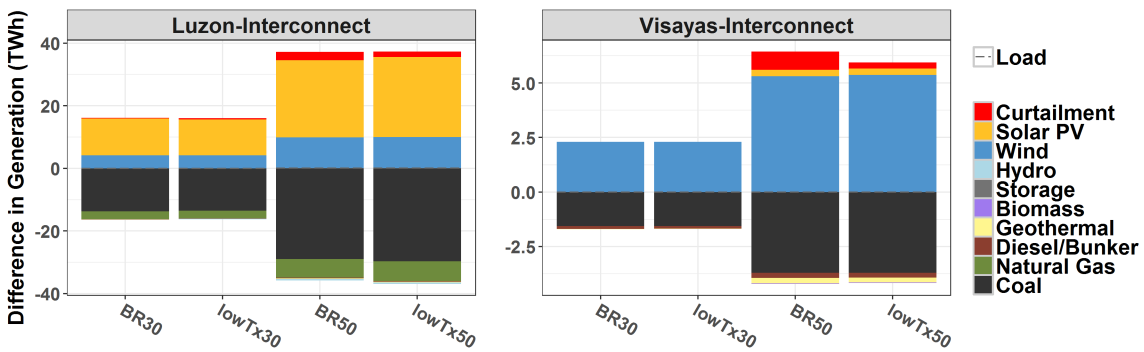


Figure 26. Annual Luzon and Visayas system generation differences by generator type relative to the Base Case

Note: Y-axes between the left and right panels are not the same scale.

Similar to the RE penetration duration curves for the Luzon-Visayas system shown in Figure 24, the individual interconnection RE penetration duration curves in Figure 27 show virtually no difference between the two 30% RE scenarios, while showing small differences between the two 50% scenarios. RE penetration in Luzon follows a similar pattern to the aggregated Luzon-Visayas curve. The Visayas curve demonstrates deviations in RE penetration for roughly the highest 10% penetration periods. This result is consistent with the differences in Visayas curtailment in the 50% scenarios and is likely driven by a combination of transmission congestion and system flexibility limitations.

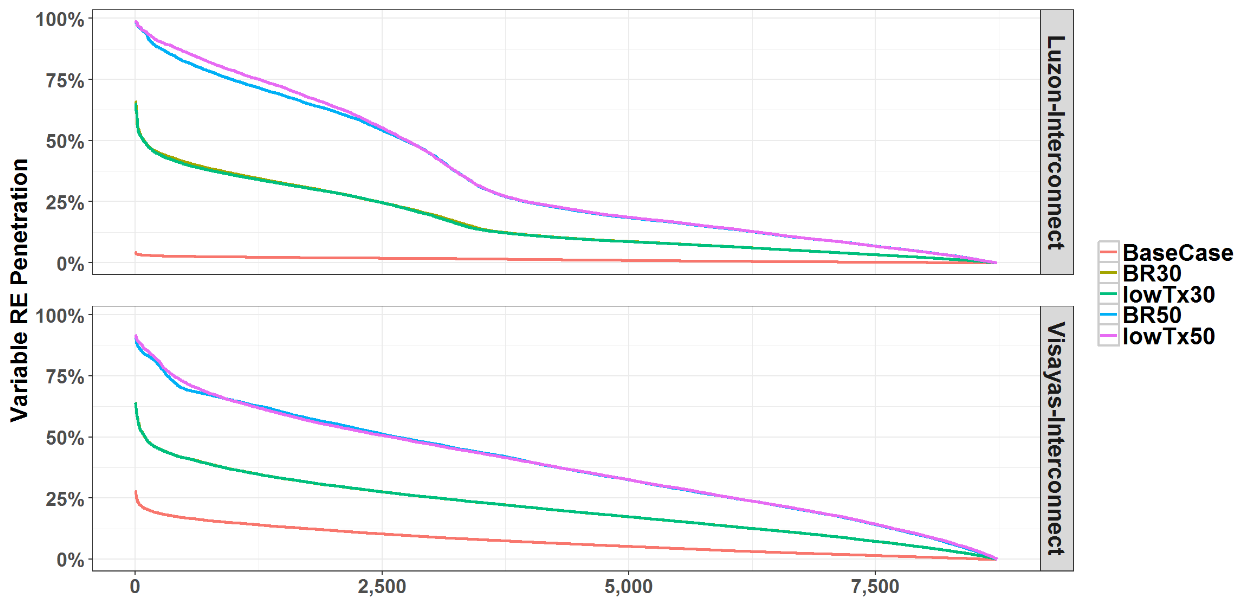


Figure 27. Luzon and Visayas system instantaneous variable RE (solar and wind) penetration duration curve

4.3 How Will Higher Variable RE Penetrations Impact the Operation of the Conventional Generation Fleet?

4.3.1 Results from the 2030 Core Scenarios

As described in Section 3.3, an increase in the penetration of variable RE will change the net load profile, which defines the non-variable RE generation and ramping requirements to mitigate variable RE curtailment. This analysis indicates that the planned 2030 fleet is capable of accommodating 30% or 50% RE generation. However, achieving these high RE targets is likely to involve several meaningful changes to the operation of the conventional fleet (both thermal generators as well as "dispatchable" RE technologies such as hydropower and geothermal). These changes will be most significant for the coal and natural gas fleet, which, as shown in Section 4.2, experience the largest reduction in annual generation in the high RE scenarios relative to the Base Case.

In addition to changes in annual generation, **the frequency of conventional generator starts and stops will change as solar and wind penetration increase**. Figure 28 illustrates the total number of annual generator startups for each fuel type, differentiating RE site selection methods (Base Case, BR, and lowTx) and RE penetration level. Across almost all fuel types, the higher penetration scenarios experience more startups per year, despite the overall drop in generation from thermal fuels. RE selection method has a smaller and less consistent impact. While the number of startup events helps to describe the cycling impacts of generators, it is also important to understand the duration of online time associated with each startup. Figure 29 shows the average hours online per startup.

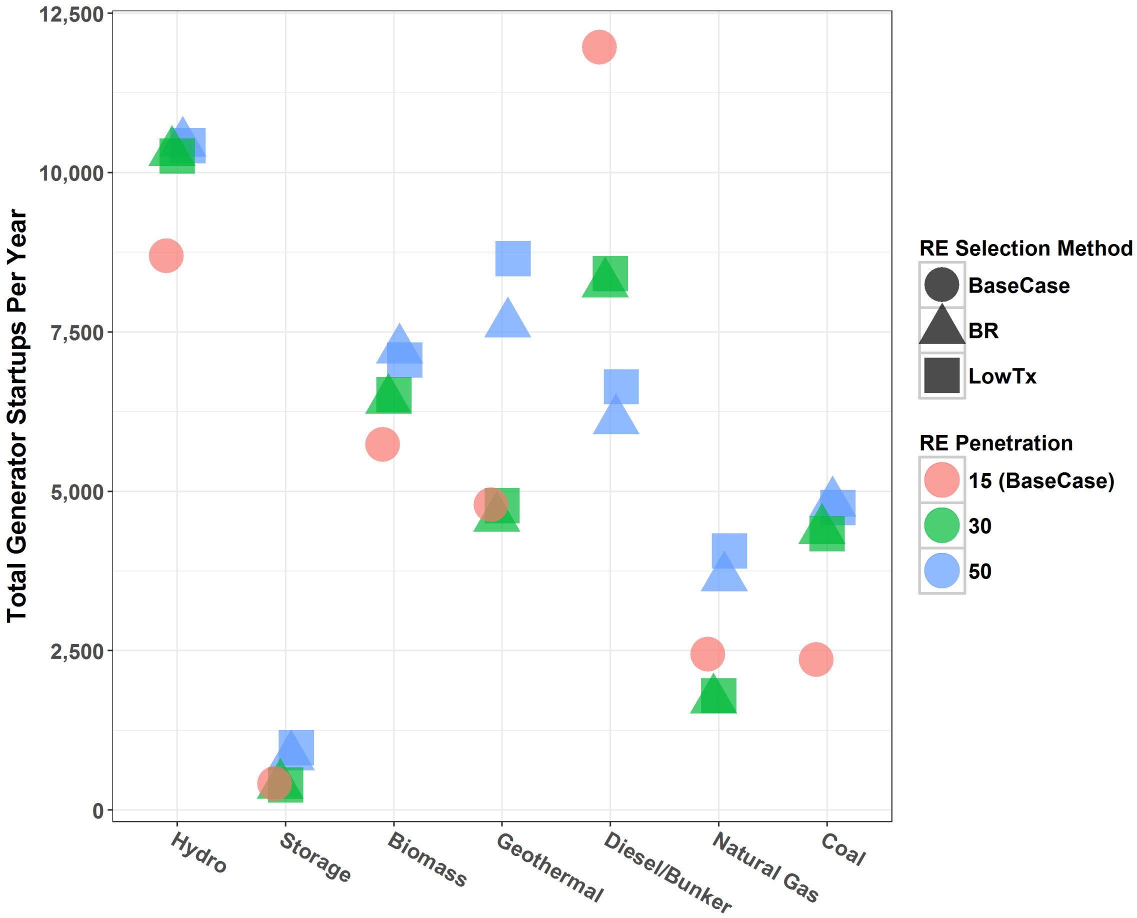


Figure 28. Total modeled Luzon-Visayas generation startups

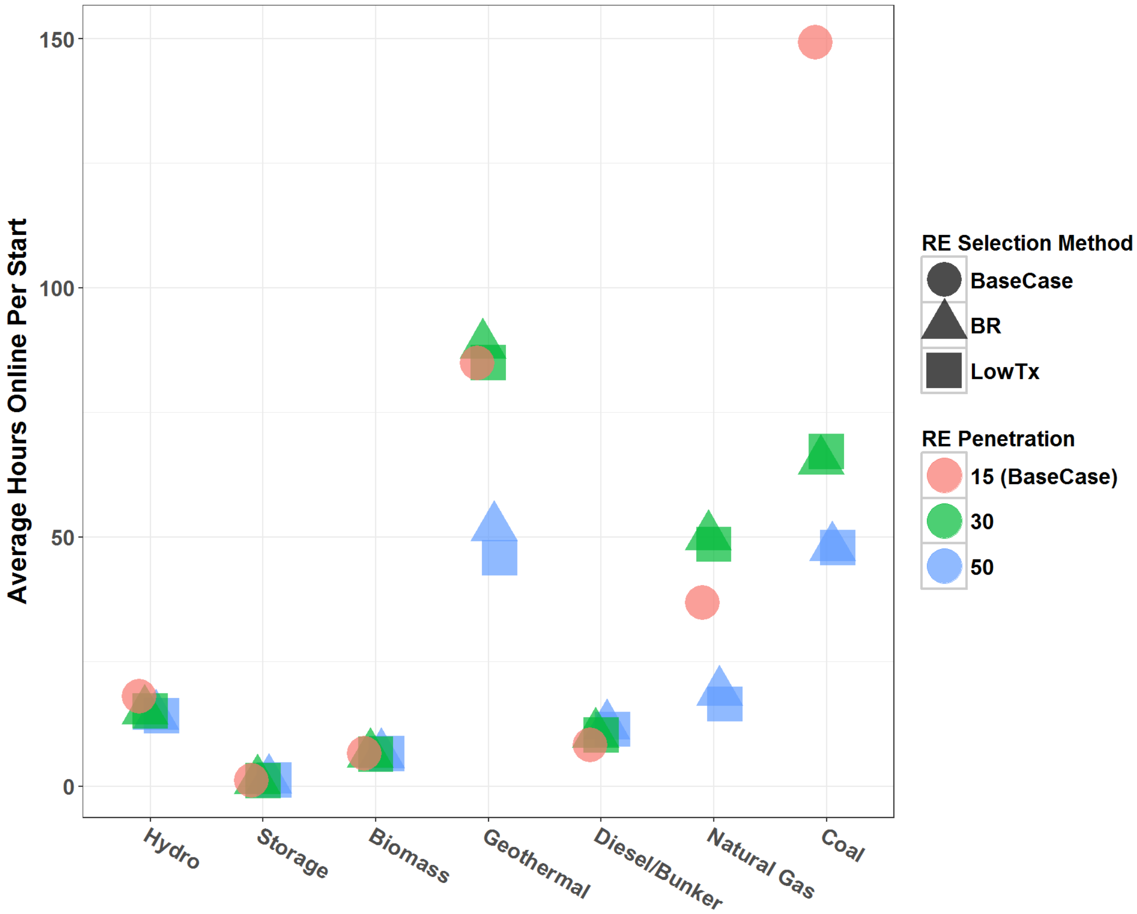


Figure 29. Average hours online per startup

Additionally, as RE penetration increases, the amount of time that conventional generators spend at their minimum stable output levels will change. Figure 30 shows the average time that units of each fuel type spend at their (non-zero) minimum generation level, using the same convention for differentiating scenarios as Figure 28.

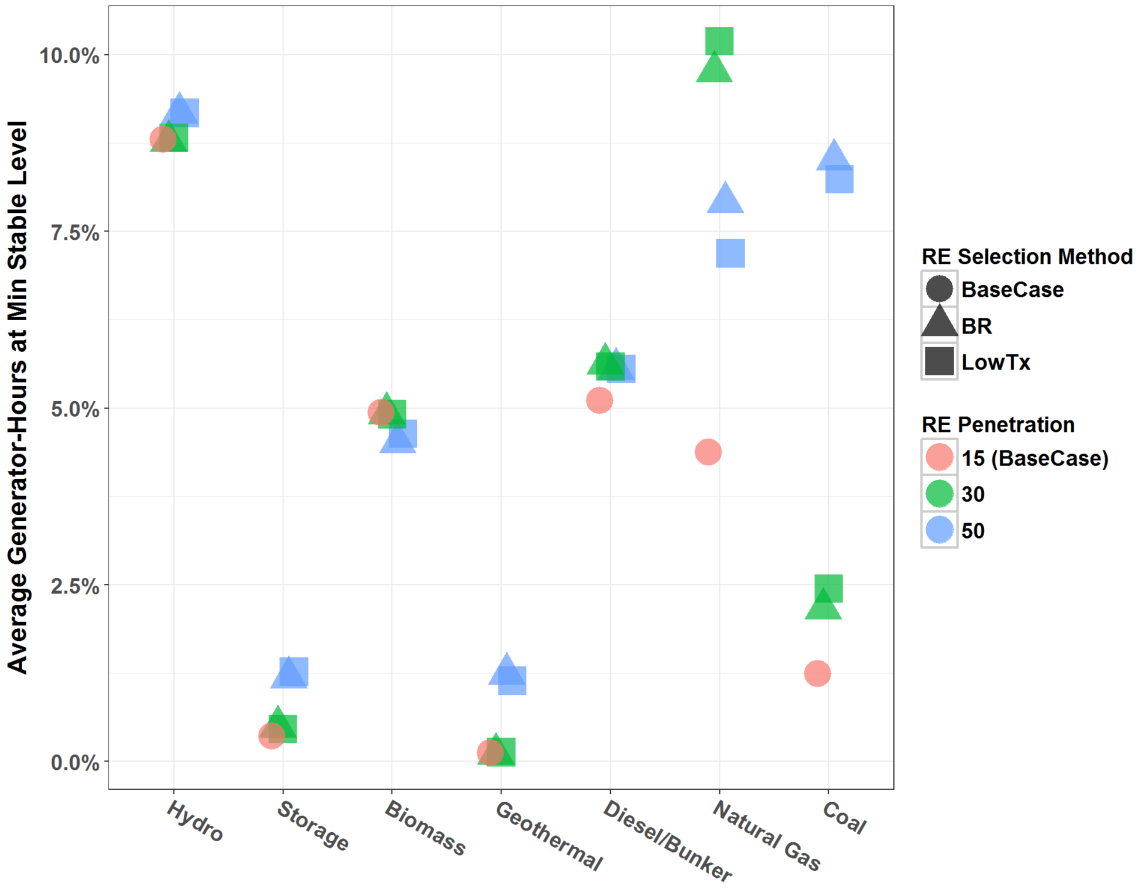


Figure 30. Average time spent at minimum generation set point by generator type

Finally, **capacity factors for some generators—especially coal and natural gas—will decrease as RE penetration increases**. Figure 31 and Table 13 show the annual capacity factor for each technology type for each 2030 scenario. Only coal and natural gas experience significant declines in capacity factors between the high RE scenarios and Base Case.

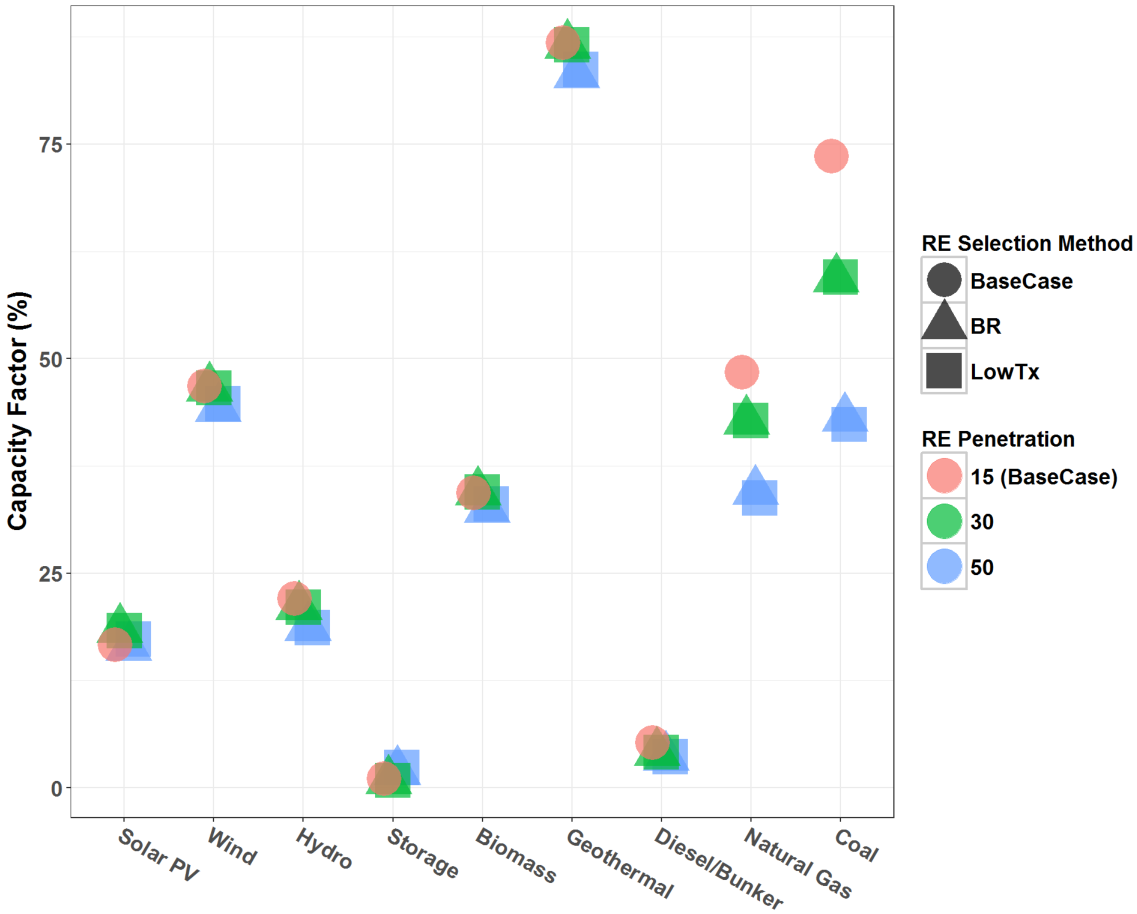


Figure 31. Average modeled plant capacity factor by generator type

Table 13. Average Modeled Plant Capacity Factor (%) by Generator Type in Each 2030 Scenario

	Biomass	Coal	Diesel/ Bunker	Geothermal	Hydro	Natural Gas	Solar PV	Storage	Wind
Base Case	34.4	73.6	5.2	86.8	22.1	48.4	16.7	1.0	46.8
BR30	34.5	59.3	4.1	86.6	21.1	42.8	18.5	0.8	46.6
lowTx30	34.5	59.5	4.1	86.6	21.0	42.8	18.3	0.8	46.6
BR50	32.5	43.1	3.6	83.1	18.7	34.6	16.4	1.9	44.2
lowTx50	33.1	42.3	3.6	83.7	18.6	33.7	17.3	2.4	44.7

Taken together, Figure 28, Figure 30, Figure 31, and Table 13 highlight several trends in the high RE scenarios relative to the Base Case:

- Hydropower (including pumped hydro storage) and biomass generators start more frequently in both the 30% and 50% RE scenarios; however, they do not spend significantly more time operating at their minimum stable levels. In general, the capacity factors of these generator types decrease only slightly in the high RE scenarios.

- Geothermal generator operation does not change significantly in the 30% RE scenarios. However, under the 50% RE scenarios, the frequency of geothermal generator starts and the amount of time these units spend at their minimum stable levels both increase substantially. Geothermal plant capacity factor decreases slightly in the 50% case.
- Diesel/bunker generators start less frequently and spend slightly more time at their minimum stable outputs as RE penetration rises. As shown in Figure 8, the variable costs of diesel/bunker facilities are higher on average than those of other generator types, so these generators tend to be dispatched last in the merit order operation. For this reason, in the Base Case operations, diesel/bunker generators primarily meet peaking needs and therefore start and stop frequently. As significant new solar and wind-generating capacity is added in the high RE scenarios, these facilities cycle on and off less frequently because a combination of lower-cost generators can meet peaking needs. The capacity factor of these facilities therefore decreases slightly from its already-low level in the 30% and 50% RE scenarios.
- The utilization of natural gas generators changes as RE penetration increases. In the 30% RE scenarios, natural gas generators start less frequently but spend significantly more time at their minimum stable levels. As low-cost wind and solar displace the need for diesel/bunker generators to meet peaking needs, natural gas plants meet both mid-merit and peaking needs and therefore are online more frequently, cycling to and from their minimum stable levels. This pattern changes in the 50% RE scenarios, in which natural gas units start more frequently, but spend fewer hours operating at minimum stable levels relative to the 30% RE scenarios (though more hours relative to the Base Case). In the 50% RE cases, natural gas generators are primarily peaking plants, as mid-merit needs are met with less expensive generators. The capacity factor of natural gas facilities decreases as RE penetration increases.
- Coal plants start more frequently in the 30% and 50% RE scenarios, though the increase in annual starts in the 50% RE scenario relative to the 30% RE scenario is relatively small. The reverse is true for time spent at minimum stable level; in the 50% scenario, coal generators spend significantly more time operating at minimum stable than they do in the 30% RE scenario. The capacity factor of coal generators decreases more significantly than that of other technologies as RE penetration increases.
- The RE siting methodology (BR, lowTx) does not significantly impact the number of generator startups and the number of generator hours at minimum stable level in the 30% RE scenarios. In the 50% scenarios, small differences between the BR and lowTx scenarios appear: For example, geothermal, diesel/bunker, and natural gas generators start more frequently in the lowTx50 scenario than they do in the BR50, while geothermal, natural gas, and coal generators spend more hours at their minimum stable levels in the BR50 scenario than they do in the lowTx50 scenario.

These patterns indicate a need for more variable operation of the conventional fleet—especially coal and natural gas generators—as the share of solar and wind in the power mix increases. Figure 32 further illustrates some of the operational changes that may be necessary in moving from the Base Case to the high RE scenarios (in this case, the BR30 and BR50 scenarios), focusing on hourly operations in an extreme case when daily peak load occurs in the evening. In the Base Case, coal generators have a relatively constant output over the course of the day, cycling at a gradual rate from a daily minimum of 7.2 GW to a maximum of 11.4 GW. In contrast, in the BR50 scenario for the same day, coal turns down to a much lower level (2.9 GW) when solar generation reaches its midday maximum and must ramp quickly to 9.4 GW to meet the evening peak load after the sun sets.

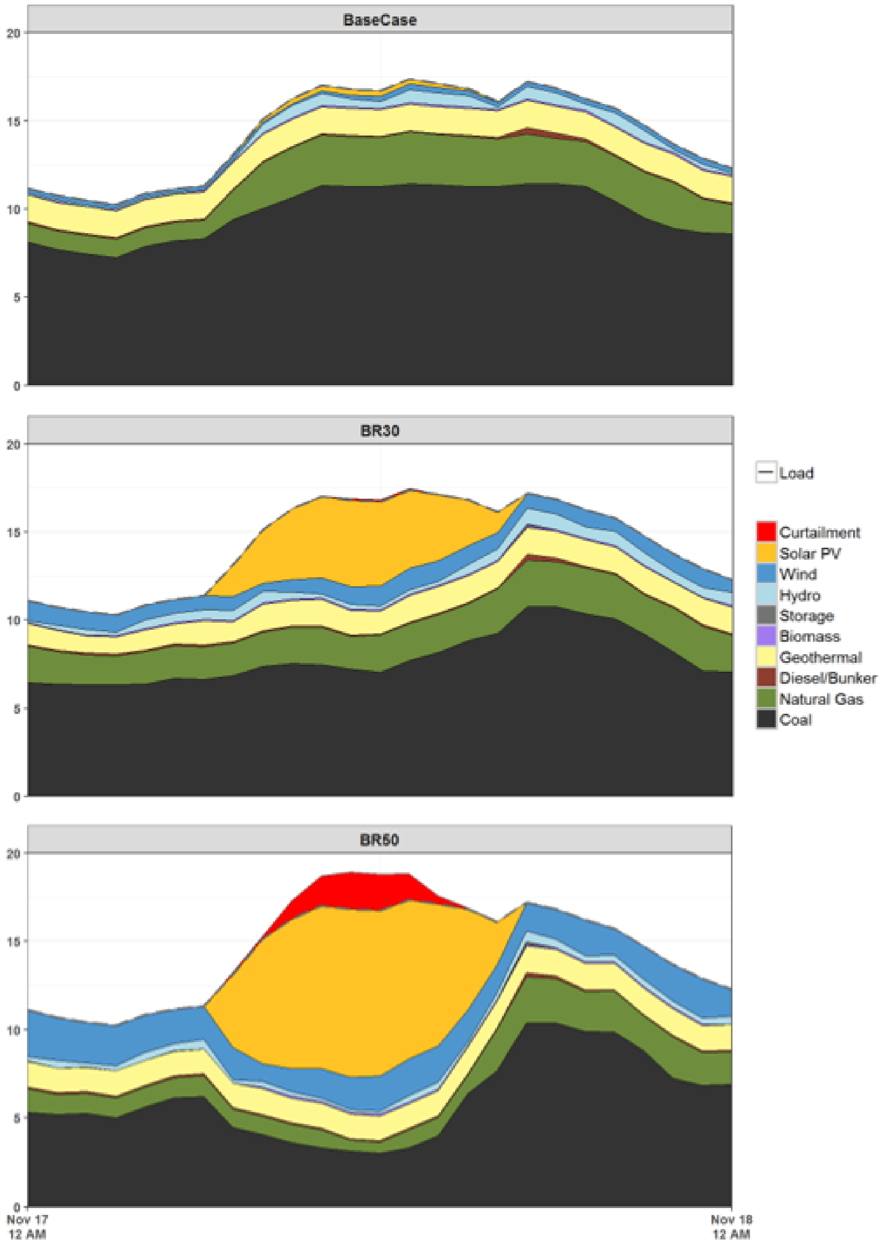


Figure 32. Hourly generation schedule on November 17 (Visayas evening peak day) in the Base Case, BR30 and BR50 scenarios

Based on the data available, the existing (and by projecting the same capabilities, the planned) generation fleet has the technical capabilities to start and stop more frequently, spend more time at minimum stable levels, and operate in the more flexible manner exhibited in Figure 32. As shown, extracting this inherent flexibility through operational rules and/or market incentives will become increasingly important as RE penetration increases and may require significant changes to the way generators operate today.

The MWG's modeling approach idealistically assumes that generators will bid their full technical capabilities (e.g., technical minimum stable level) into the market. Perhaps more importantly, the model assumes that the system operator is able to schedule units to turn on and off based on least-cost operations. This practice is known as *unit commitment* or, in some cases, centralized market operations. Unit commitment differs from the current operation of the Philippine power system, which allows generators to self-schedule their availability to the grid (self-commit). Currently, when generators indicate their availability, the market operator automatically commits them at their technical minimum. The Philippine power sector is in the process of implementing a new market management system, which will set the technical minimum set point at zero (0) and allow generators to manage their minimum loading through their offer prices. While this change may enable more flexibility than the current market practice of dispatching generators at their technical minimum generation set point, movement toward a centralized market design for unit commitment would help achieve the most economic efficient system balance as well as the flexible operation apparent in the modeled results.

Section 5 describes different operational and market designs that could help facilitate these changes.

4.3.2 Sensitivity Analysis: Exploring the Impacts of Varying the Flexibility of the Conventional Fleet

In addition to more fully utilizing the inherent flexibility of the existing fleet, the Philippine power sector planners can encourage flexibility by procuring new generators with flexibility capabilities (e.g., low minimum stable levels, short down times, fast ramping). To more deeply understand the value of flexible generation to variable RE integration, the MWG conducted a sensitivity analysis comparing the impacts of relatively flexible and inflexible generation fleets in the Luzon-Visayas system. This sensitivity analysis varied two key characteristics of generator flexibility: minimum stable level and minimum downtime (i.e., the minimum amount of time a generator must remain off before it can start again).[20]

The MWG conducted this sensitivity analysis specifically on the BR50 scenario, which exhibited the most significant curtailment and other impacts relative to the other high RE scenarios, with the objective of determining how conventional generator flexibility mitigates or exacerbates these impacts. To construct the sensitivity analysis, the MWG replaced the default unit-specific minimum stable level and minimum downtime values in the core BR50 scenarios with a set of reference values for "flexible" and "inflexible" generators. The basis for these reference values is the International Energy Agency's (IEA's) *The Power of Transformation* report (IEA 2014), which summarizes survey and literature values for minimum generation and startup time for various generator types and differentiates between flexible and inflexible coal generators. The MWG used these values (using startup time in the IEA report as a proxy for minimum downtime) to develop two new scenarios:

- ***"BR50_IEAFlex" scenario*****:** applies the more flexible set of IEA reference values for each generator type
- ***"BR50_IEAInflex" scenario***: applies the less flexible set of IEA reference values for each generator type.

Table 14 and Table 15 define the minimum stable factor and minimum downtime assumptions, respectively, for each of these scenarios and also compare these values to the default assumptions in the core scenarios. Because the generator types in the IEA report do not exactly match the generator types in this study, the MWG in some instances used multiple generator categories from the IEA report to develop a range of minimum stable factor and minimum downtime value for a single generator type in this study. For example, IEA does not include a diesel/bunker generator category, so the MWG used the values from the "Steam" and "Other" categories to define reference flexibility characteristics for steam turbine diesel/bunker generators. For some generator types (e.g., combined cycle technologies) IEA does not differentiate between flexible and inflexible parameters.

[20] Ramp rate is another important flexibility characteristic but is not included in this analysis, as varying ramp rate is not likely to have major impacts in an hourly study.

Table 14. Minimum Stable Factor Assumptions for Flexible Generation Sensitivity Analysis, Expressed as a Percentage of Maximum Dependable Capacity

FUEL	CORE SCENARIOS (average for Luzon-Visayas system based on DOE and load flow data)	IEAFlex SCENARIO	IEAInflex SCENARIO
Combined Cycle Diesel/Bunker	22.2	40	40
Combined Cycle Natural Gas	54	40	40
Combustion Turbine Diesel/Bunker	31.7	15	50
Dam Hydro	19.4	0	0
Biomass	86.1	50	50
Steam Turbine Coal	33.4	30	60
Steam Turbine Diesel/Bunker	44.4	30	50
Steam Turbine Geothermal	17.6	30	50

Table 15. Minimum Downtime Assumptions for Flexible Generation Sensitivity Analysis, Expressed in Hours

FUEL	CORE SCENARIOS (average for Luzon-Visayas system based on DOE data)	IEAFlex SCENARIO	IEAInflex SCENARIO
Combined Cycle Diesel/Bunker	8	3	3
Combined Cycle Natural Gas	8	3	3
Combustion Turbine Diesel/Bunker	2	0.16	2
Dam Hydro	-	0.16	0.16
Biomass	1	2	3
Steam Turbine Coal	12	4	8
Steam Turbine Diesel/Bunker	-	3	2
Steam Turbine Geothermal	0	3	2

As Table 14 illustrates, the Philippine fleet (as characterized by data from DOE and NGCP) does not fit uniformly into either the “flexible” or “inflexible” definition. For example, the average minimum stable factor for Philippine coal generators (33.4% of maximum dependable capacity) is similar to IEA’s flexible definition of this metric (30%). Conversely, Philippine combined cycle natural gas generators are relatively inflexible (minimum stable factor of 54%) compared to IEA reference values (40%). For this reason, the sensitivity analysis compares the modeled solutions to the IEAFlex and IEAInflex scenarios only to one another—not to the core BR50 scenario that uses the Philippine-specific assumptions for minimum stable factor and minimum downtime. The objective of this sensitivity analysis is to compare a more and less flexible generation fleet; in reality, the Luzon and Visayas fleets fall somewhere between these hypothetical reference fleets.

Figure 33 illustrates a subset of results from the two flexible generation sensitivity analyses and highlights some of the operational differences between the more and less flexible generation fleets in a 2-day period in January (which encompasses the lowest load period in the early morning of January 22). The two scenarios exhibit significantly different coal operations during this period. In the BR50_IEAFlex scenario, aggregate coal generation is able to ramp more quickly, presumably because more coal generators are able to come online at their minimum levels after shutting down for relatively short periods. The BR50_IEAInflex scenario, in contrast, is more reliant on relatively expensive natural gas to ramp quickly when the sun sets each day.

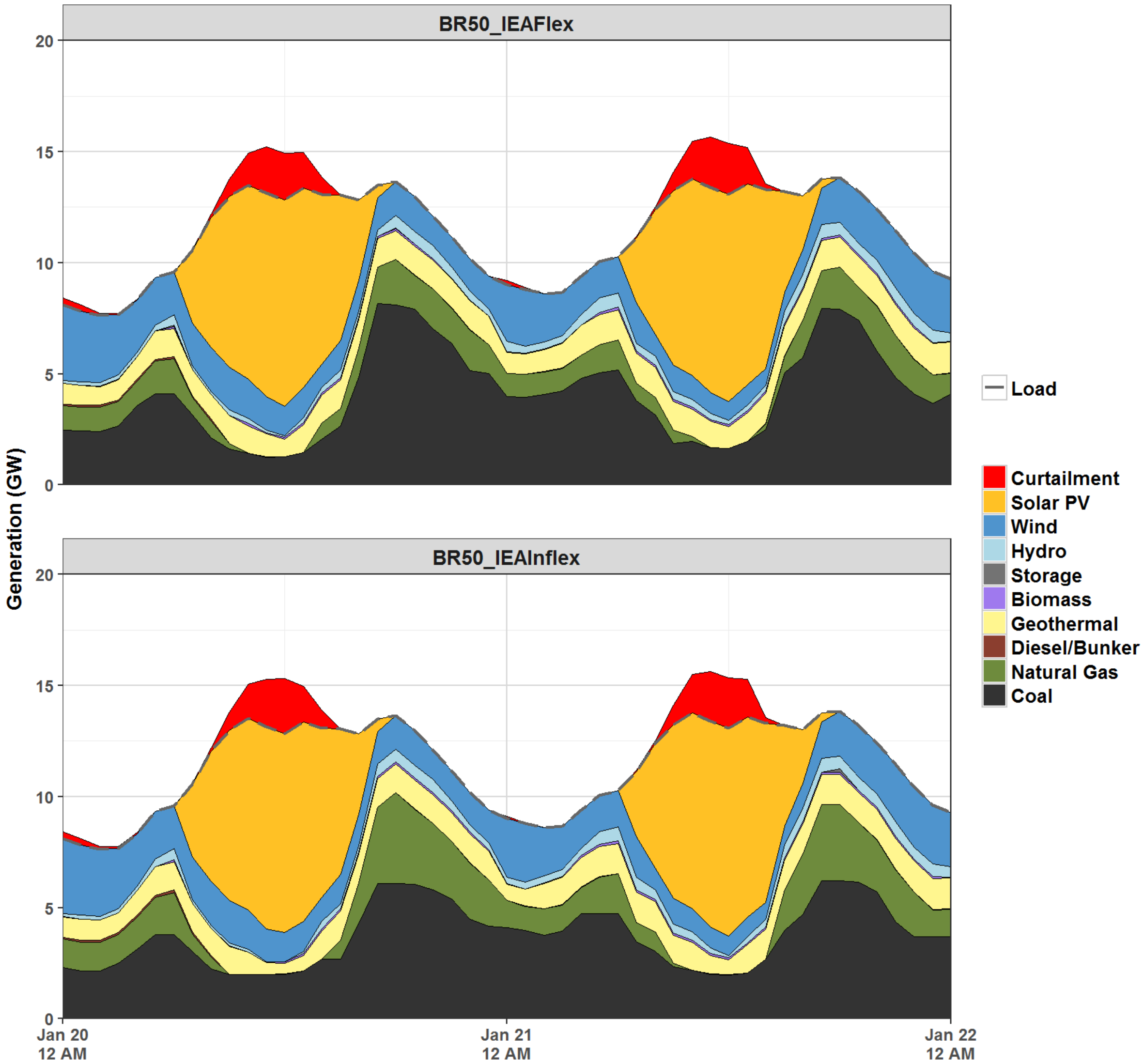


Figure 33. Hourly generation schedule for January 20–22 (annual minimum load period) in the "flexible" and "inflexible" BR50 sensitivity scenarios

Table 16 compares selected results for the BR50_IEAFlex and BR50IEAInflex scenarios. These results indicate a modest increase in RE penetration, reduction in solar and wind curtailment, and decrease in variable costs in the flexible relative to the inflexible scenario. Even these modest improvements may be meaningful—for example, how production cost savings between the BR50_IEAFlex and BR50_IEAInflex scenarios are approximately 1%. This decrease in costs represents a savings of more than 1.5 billion PHP annually.

Table 16. Selected Results Comparing the Flexible and Inflexible Reference Fleets

	BR50_IEAFlex	BR50_IEAInflex
Annual RE penetration (wind and solar penetration)	47.9% (*36.1%)*	47.5% (*35.9%)*
Annual CO_2 emissions (tons)	59,500	59,000
Annual solar and wind curtailment	7.1%	7.7%
Total variable costs	188.9 billion PHP	190.4 billion PHP

4.4 How Does the Transmission System Affect RE Utilization and What are the Impacts of Transmission Enhancements?

4.4.1 Results from the 2030 Core Scenarios

The curtailment differences across scenarios highlighted in Sections 4.1 and 4.2 indicate system limitations due to transmission access and generator flexibility. To understand the limitations imposed by the modeled 2030 transmission system, we analyzed transmission congestion under each scenario. Line congestion is defined as a binding transmission line flow limit during a particular period (hour). Figure 34 shows duration curves for the total number of congested lines in each scenario. Without modeling additional wind and solar resources, the Base Case has congested transmission lines in 2,800 out of 8,760 hours in the year (32%). Wind and solar integration increases the frequency of transmission congestion, especially in the BR scenarios where sites are selected without considering the limitations of the transmission infrastructure. The high RE scenarios are transmission-constrained in roughly 60% of hours (5,200 hours and 5,580 hours for the lowTx50 and BR50 scenarios, respectively). Congestion differences between the BR and lowTx site selections at each RE penetration level show the potential impact of transmission limitations when developing RE.

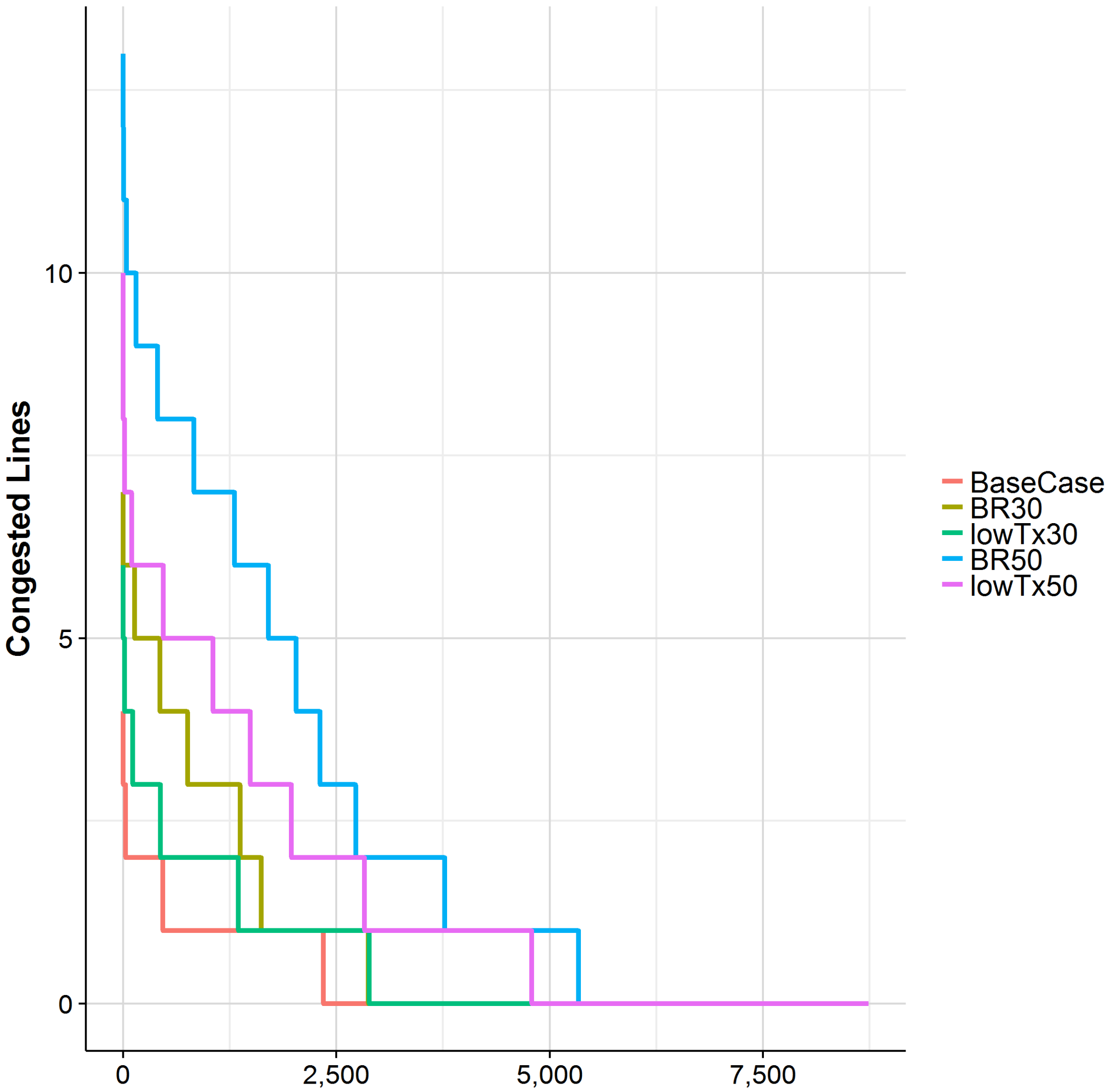


Figure 34. Number of lines congested at each hour of the year in the Luzon-Visayas system

While higher RE penetration levels experience greater congestion, this congestion does not necessarily impede RE utilization. Figure 39 displays the relationship between the congestion price and the Luzon-Visayas RE curtailment level during each simulated period. The congestion price describes the marginal cost imposed by a transmission flow limit or, conversely, the marginal value of relaxing a transmission line flow limit. While curtailment levels are correlated with congestion prices, the greatest curtailment levels do not occur when congestion is most prevalent. This suggests that **curtailment is only driven in part by transmission flow limits**. Other factors that contribute to curtailment are system (generator) flexibility, net load variability (flexibility requirements), and reserve requirements.

Comparing congestion prices and curtailment across scenarios shows that the RE site selection strategy can impact the system utilization of RE generation. Figure 12 and Figure 15 show that RE sites are more concentrated in the lowTx30 scenario than the BR30 scenario. The RE site locations in the 30% scenarios drive some additional curtailment that is correlated with congestion prices. In addition to showing that curtailment is most prevalent in the BR50 scenario, Figure 35 shows that, relative to lowTx50, more BR50 curtailment occurs in the 10,000–1,000,000 PHP/MWh congestion price range. This suggests that **considering the transmission infrastructure limitations when choosing RE locations can help avoid some operational challenges**, especially under larger amounts of RE integration.

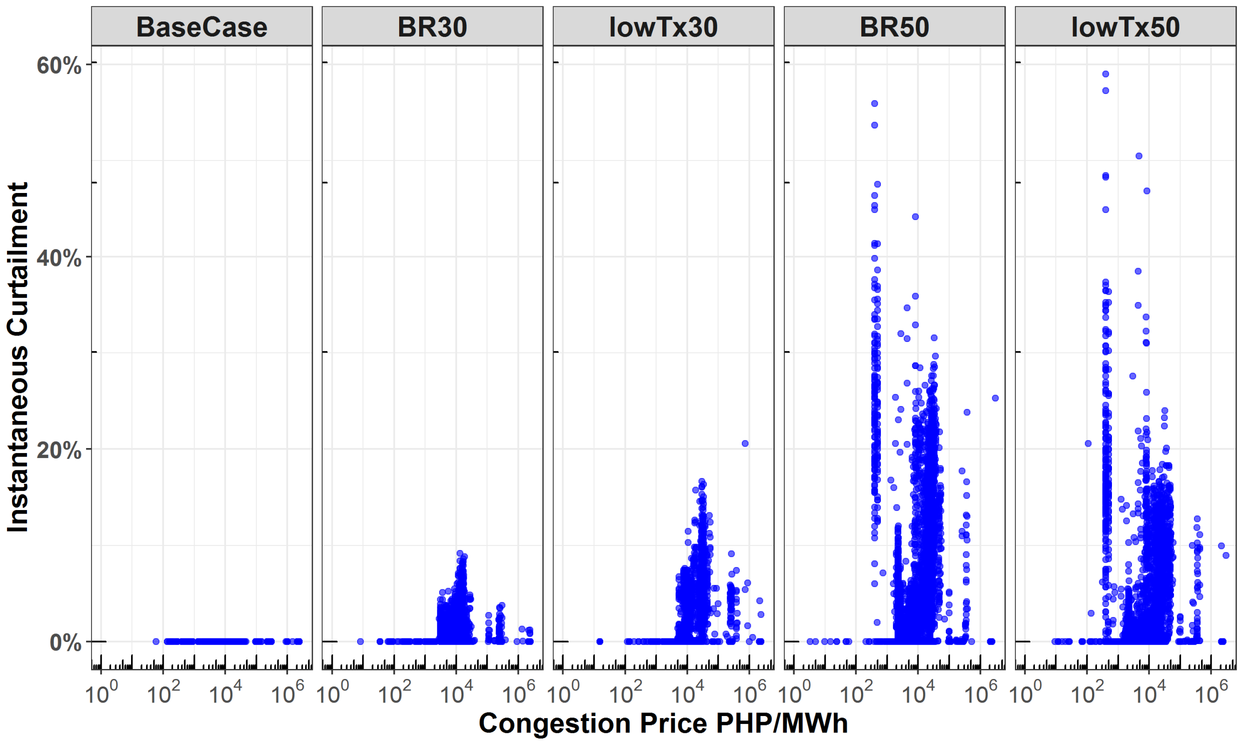


Figure 35. Congestion prices (log scale) vs. instantaneous Luzon-Visayas system curtailment

4.4.2 Sensitivity Analysis

To understand the impacts of increasing transmission infrastructure, the MWG conducted two sensitivity analyses on the BR50 scenario:

- ***"RlxTxLim" sensitivity***: Adds transmission flow capacity along congested paths in the BR50 scenario. To simulate the impacts of additional transmission capacity, the power flow limits of 22 lines were increased by 50% above their original rated capacities. In total, 3.4 GW of transmission capacity was added to the Luzon-Visayas system. Figure 36 shows the locations of the transmission lines that are relaxed in the RlxTxLim sensitivity.
- ***"NoTxLim" sensitivity:*** Relaxes all transmission flow limits in the entire system. To understand the theoretical limit of BR50 capacity operations, all transmission flow limits were removed.

Figure 36. RlxTxLim scenario transmission limits increased by 50%

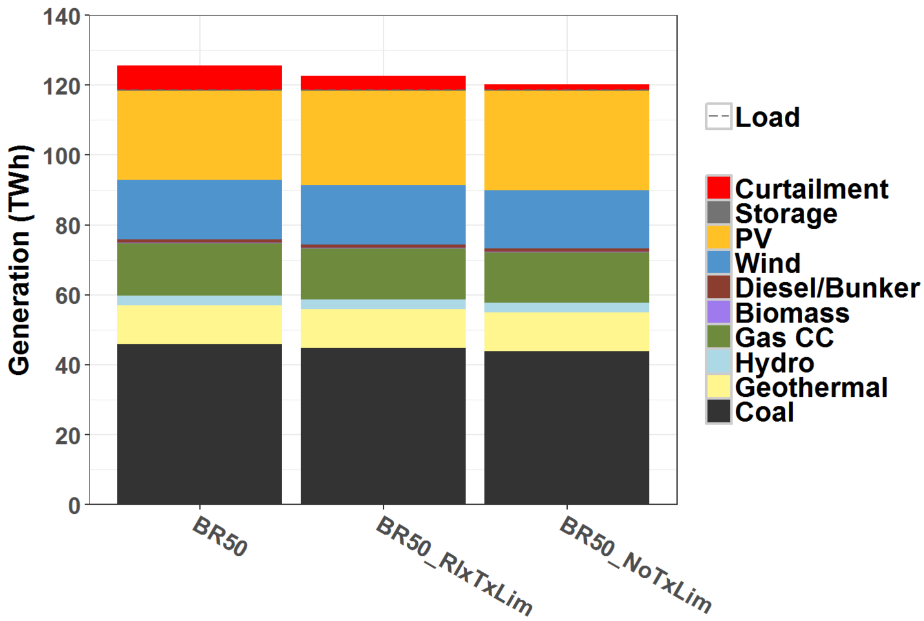


Figure 37. Total annual generation and curtailment for the BR50 transmission sensitivity analysis

Figure 37 shows the total annual generation and curtailment in the BR50 scenario and transmission sensitivities (BR50_RlxTxLim and BR50_NoTxLim). Curtailment reduces from 7.6% in the BR50 scenario to 3.8% in the BR50_RlxTxLim scenario and 1.9% in the BR50_NoTxLim scenario. Figure 38 shows that the additional simulated transmission capacity enhances solar utilization that primarily displaces coal generation. The 38% reduction in curtailment achieved by adding 3.4 GW of transmission capacity in the RlxTxLim scenario indicates that additional transmission capacity can lead to increased RE utilization. However, the presence of some curtailment in the case where transmission limits are completely relaxed (NoTxLim) indicates that **curtailment could not be completely eliminated by transmission enhancements alone**.

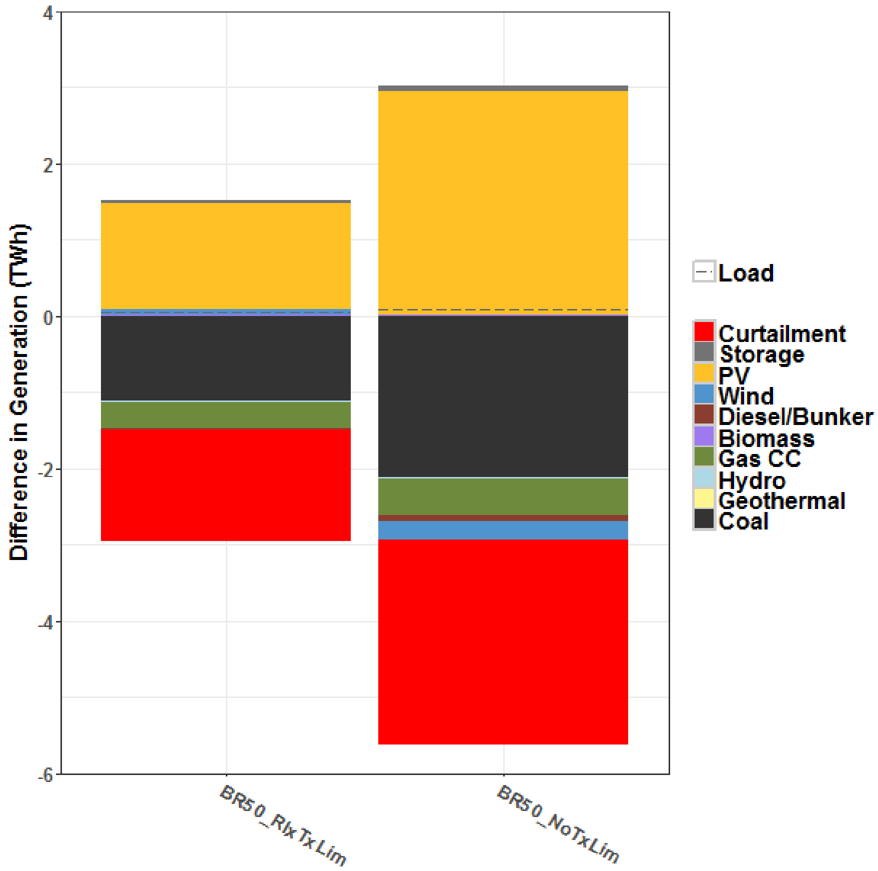


Figure 38. Total annual generation and curtailment differences in the transmission sensitivity scenarios relative to the BR50 scenario

4.5 What Implications Might High RE Scenarios Have on Reliability?

4.5.1 Results from the 2030 Core Scenarios

Reliability is a primary concern of the power system operator. This study seeks to identify potential impacts of high RE scenarios on certain elements of reliability—namely, the holding of reserves. Analysis of voltage, stability, and recovery after a contingency on an intra-hour level is beyond the scope of this hourly production cost modeling study. Assessing these issues via load flow simulations is a crucial area for follow-on study by NGCP and other power system stakeholders.

As Section 2 describes, this study does not simulate the deployment (or the deliverability) of any reserve product through the transmission network. Instead, the MWG simulated the scheduled holding of each of the three reserve products (primary, secondary, and tertiary reserve in the 2030 scenarios). While this approach does not enable a direct assessment of system reliability, these simulations can address the system's ability to procure reserves according to the defined requirements.

Based on the definitions of reserve products and QFs detailed in Section 2, Figure 39 shows the annual modeled reserve provision in each of the 2030 scenarios. Annual reserve provision is expressed as a percentage, which the MWG calculated by dividing the simulated annual provision (in GWh) by the requirement (also in GWh) for each reserve product in each of the two grids. Thus, 100% indicates that all reserve requirements of a specific type were met.

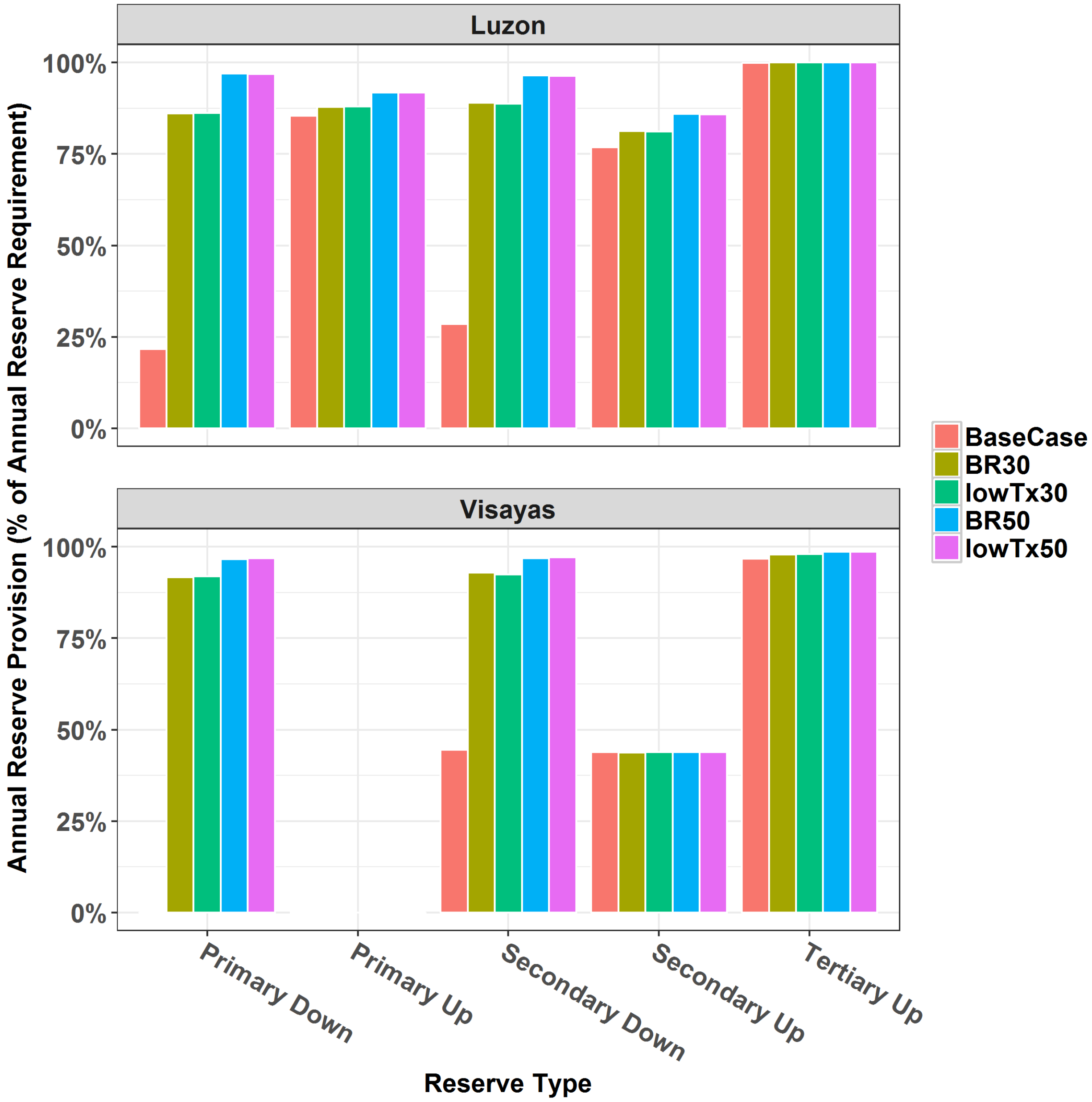


Figure 39. Annual modeled reserve provision by reserve product in the Luzon and Visayas grids

Figure 39 illustrates some of the implications of the various 2030 scenarios on the ability of the Luzon-Visayas system to meet its reserve requirements. First, **the 2030 system may face reserve shortages under the requirements assumed in this study.** These shortages are most pronounced in the Visayas grid and for primary and secondary up reserves, which do not meet 100% of the annual requirement in any scenario. Perhaps most critically, the Visayas grid holds no primary up reserves in any scenario.

Reserve shortage results from two related factors: the capacity adequacy of the system and the availability of QFs to provide reserves. Figure 40 and Figure 41 show the average hourly and daily reserve provision in each scenario, aggregated for both grids and all products. These figures as well as Figure 39 indicate that the Base Case experiences the highest levels of reserve shortage for all products. For all of the reserve products in Luzon as well as the down reserves and tertiary reserves in Visayas, as RE penetration increases, reserve provision also increases. Enhanced reserve provision in the 30% and 50% RE scenarios occurs because the penalty value for lost load is much higher than the penalty value for reserve shortfall. Thus, the addition of solar and wind capacity in the high RE scenarios relative to the Base Case system reduces the demand for energy provision from QFs, which can then be held for reserve provision. This enhancement of reserve provision does not necessarily reflect benefits specific to solar and wind; similar impacts would likely occur if the capacity from other generator types were added to the Base Case.

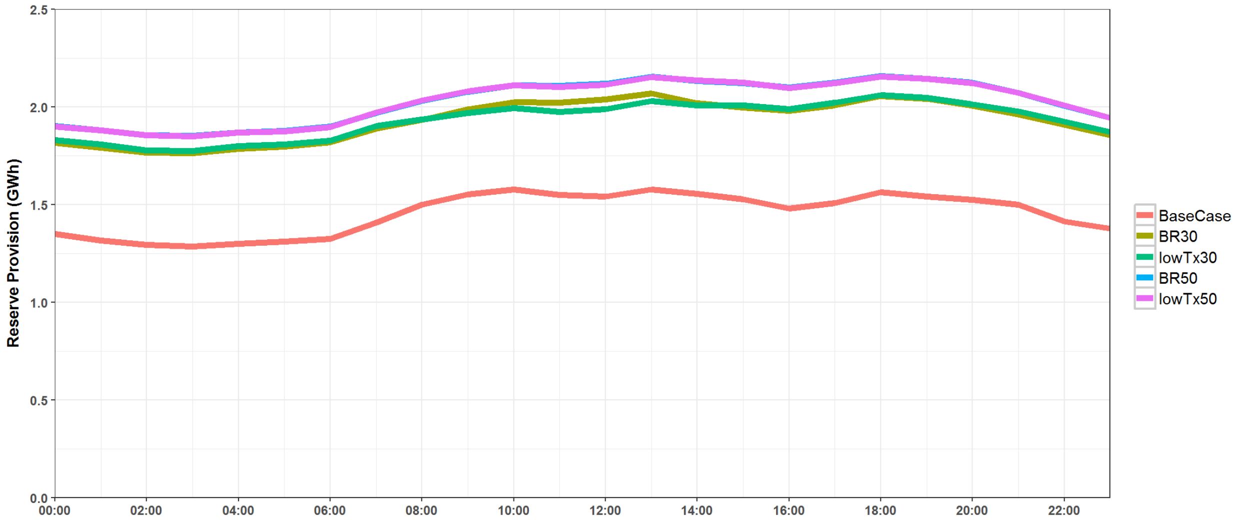


Figure 40. Average hourly modeled reserve provision (all products)

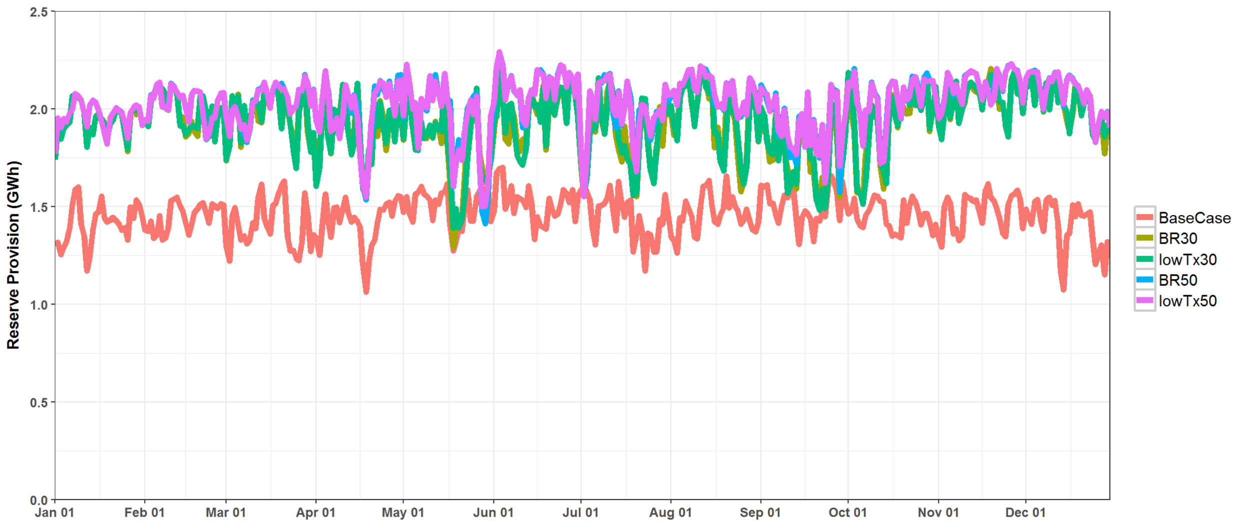


Figure 41. Average daily modeled reserve provision (all products)

Figure 39 also illustrates a more explicit need for more QFs. The 2030 scenarios assume the same set of QFs that existed in 2014, with one exception: Additional wind generators in the 30% and 50% that do not exist in the Base Case are allowed to provide down reserves. Along with providing additional capacity that can enable non-wind QFs to provide reserves, including wind as QFs significantly improves the provision of primary and secondary down reserves in both Luzon and Visayas relative to the Base Case. This effect is particularly evident in Visayas: In the Base Case, no primary down reserve provision occurs, while in the 30% and 50% RE scenarios, the interconnection meets 85% or more of its annual reserve requirements.

This study specifically considers new wind generators as down reserve providers to illustrate the importance of encouraging communication and technology capabilities (e.g., automatic generation control [AGC]) on turbines that will enable these generators to provide this service. These technologies are available for modern wind turbines (and, to a lesser extent, solar PV systems).[21] The results above

[21] Modern wind turbines can also provide upward reserve products by pre-curtailing wind generation levels. However, upward reserve provision from wind generators was not modeled here.

indicate that **wind plants can contribute to ancillary service provision**. These services are not limited to wind; other generators, including solar as well as conventional fossil and RE units, could also potentially become QFs to provide additional down reserves. The results do not preclude conventional generators from providing these capabilities; the study merely demonstrates value specifically of wind being allowed to provide these capabilities.

4.5.2 Sensitivity Analysis

To understand options for mitigating reserve shortage, the MWG conducted two sensitivity analyses:

- ***"AddQF" sensitivity***: Allows the six new natural gas units in the 2030 scenarios to become QFs for primary and secondary reserve provision (in addition to the 2014 QFs). The MWG chose natural gas units as potential QFs because they are relatively fast acting and would be more likely than other generators to meet the ERC's requirements to become ancillary service providers. Figure 42 shows the number of QFs in Luzon and Visayas in the Base Case core and AddQF scenarios. Because no new natural gas (or hydropower) units are added to the Visayas system in 2030, the AddQF scenario does not include any additional ancillary service providers in Visayas relative to the Base Case.
- ***"1ResGrp" sensitivity:*** Assumes the same set of QFs as the AddQF sensitivity, and also allows QFs to be shared between the Luzon and Visayas grids, effectively creating one reserve-sharing group facilitated by the HVDC underwater cable. In this scenario, QFs in Luzon may provide reserves in Visayas and vice versa.

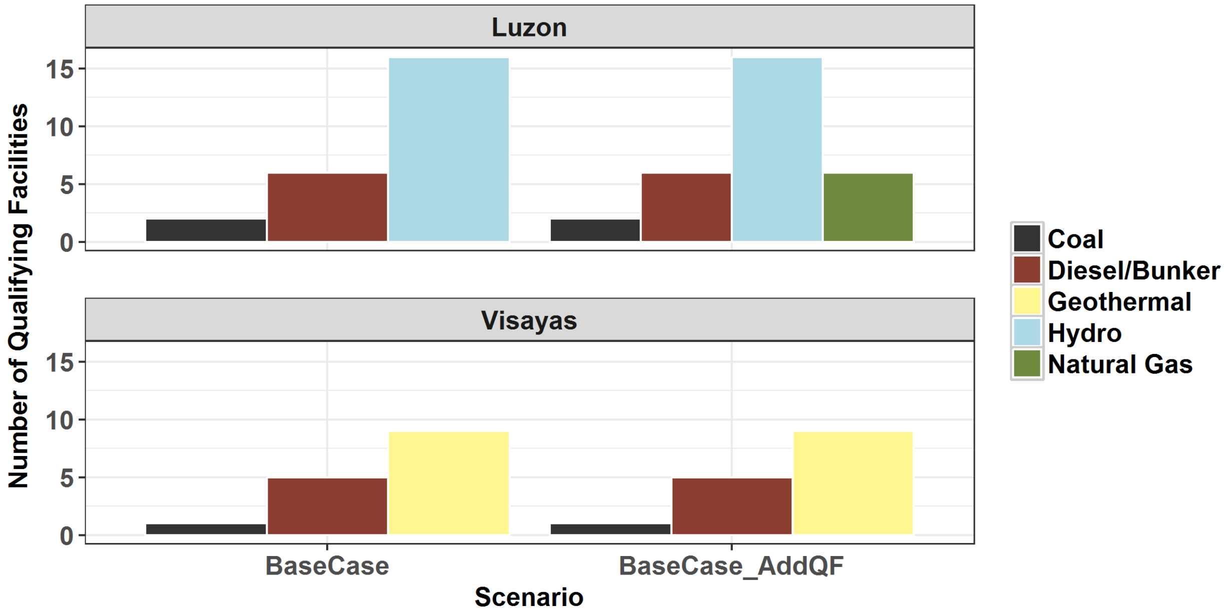


Figure 42. Number and type of units that qualify to be ancillary service providers in the core and AddQF sensitivity scenarios

Figure 43 shows the total annual provision of primary and secondary across the Luzon-Visayas system resulting from the core, AddQF, and 1ResGrp versions of the Base Case, lowTx30, and lowTx50 scenarios. The BR30 and BR50 scenarios, while not shown, exhibit similar trends across these three sensitivities. At each level of RE penetration, **adding QFs generally improves reserve provision. Furthermore, enabling reserve sharing in addition to adding QFs further reduces reserve shortages**.

The combination of increasing generation adequacy (i.e., adding new solar and wind generators in the 30% and 50% scenarios), allowing wind generators to provide down reserves and broadening the pool of QFs to include more natural gas in Luzon enables the Luzon-Visayas system to meet nearly 100% of its primary down, secondary down, and secondary up reserve requirements. For these products, the difference between the AddQF and 1ResGrp sensitivity scenarios is minimal, and both scenarios improve provision relative to the core scenario. The 1ResGrp sensitivity significantly improves the provision of primary up reserves relative to the AddQF sensitivity, as sharing QFs across the HVDC enables the QFs in Luzon to help meet some of the shortage in Visayas in the core cases. However, even in the 1ResGrp sensitivity, primary up reserve provision meets only about 90% of the requirement for this product, indicating that more qualifying facilities are likely to be needed in the future—particularly in Visayas—to meet the reserve requirements assumed in this study.

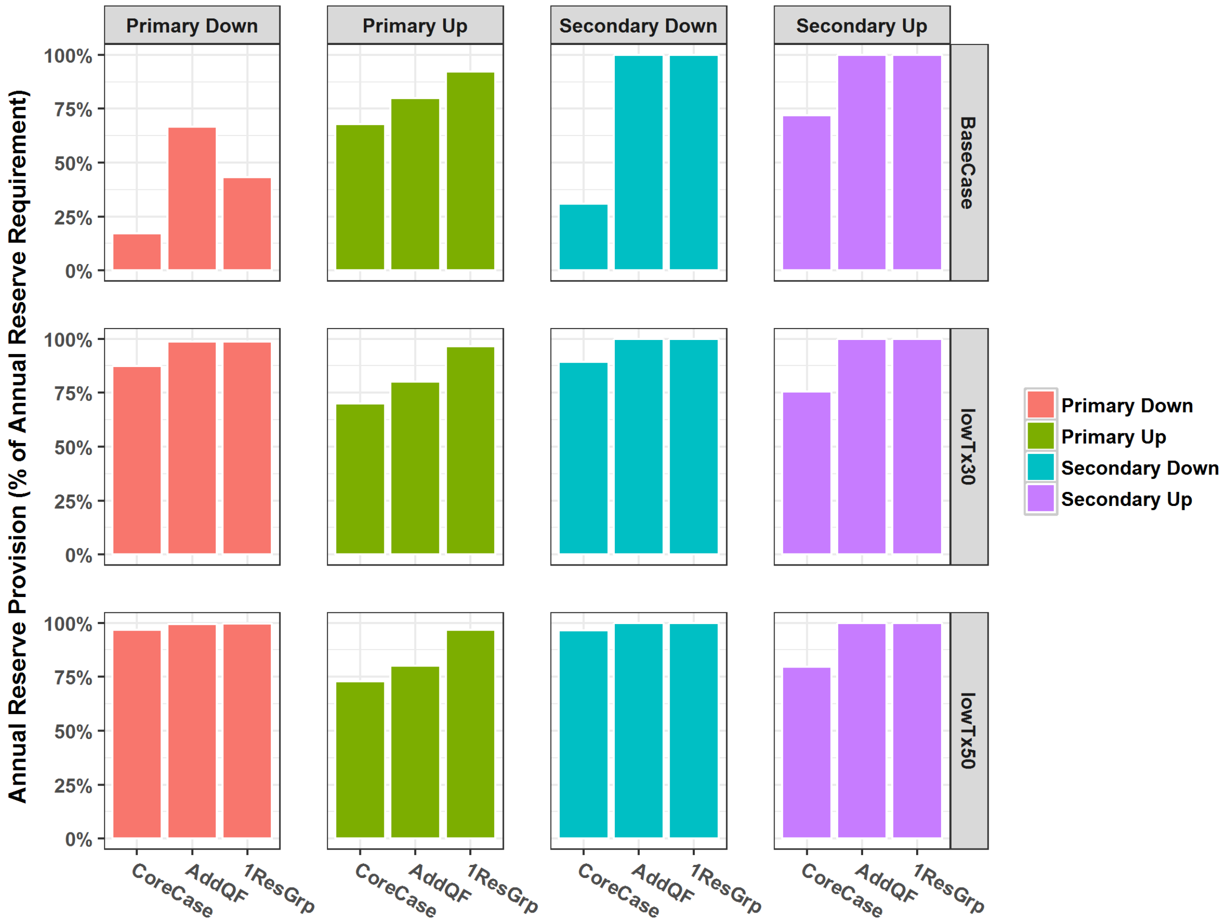


Figure 43. Annual modeled reserve provision by reserve product for the Base Case and lowTx core and reserve sensitivity scenarios

4.5.3 Implications of Reserve Requirements on RE Penetration

According to our analysis, the definition of reserve requirements and the ability of QFs to provide fast-response capabilities have the potential to be important drivers of solar and wind curtailment in the 30% and 50% RE scenarios. The Luzon-Visayas system has a limited number of fast-acting generating units that are able to ramp quickly up and down. These units are most likely to meet the stringent response requirements articulated in the ERC's *Ancillary Services Procurement Plan* to become QFs. However, because of their ramping capabilities, these units are also the most capable of responding to relatively rapid changes in solar and wind output. If the only fast-acting units must be held for reserves instead of being available to respond to variable generation, curtailment may increase in high RE cases.

The MWG was able to mitigate this issue in the 2030 model simulations by assuming QFs may ramp more quickly when they are providing reserves than when they are providing energy, as discussed in Section 2. Without this assumption, annual solar and wind curtailment, for instance, in the BR30 core scenario, increases from just 1% to over 20%. When ramping capabilities of all QFs are not fully represented in the model (or, more importantly, are not present in the system), the fast-acting units that can respond to solar and wind variability must be held for reserves, leading to curtailment of these resources. This analysis therefore underscores the importance of procuring and/or accessing flexibility capabilities of conventional generators to meeting high RE goals.

4.5.4 Other Reliability Considerations

Though this study is based on hourly production cost modeling and, by design, cannot simulate intra-hour dynamic stability, the results provide insight on certain hours of the year when stability may be a particular issue. These "periods of interest" can be examined in further detail through load flow modeling.

Figure 44 illustrates one approach to identifying periods of interest in each of the core 2030 scenarios. This figure graphs non-synchronous penetration, which is calculated as the instantaneous non-synchronous generation divided by the sum of committed synchronous capacity plus non-synchronous generation (Miller 2015). Non-synchronous generation and synchronous capacity are aggregated by interconnection to represent the sum of all inverter-based generation (including HVDC imports) and the sum of all committed spinning capacity, respectively.

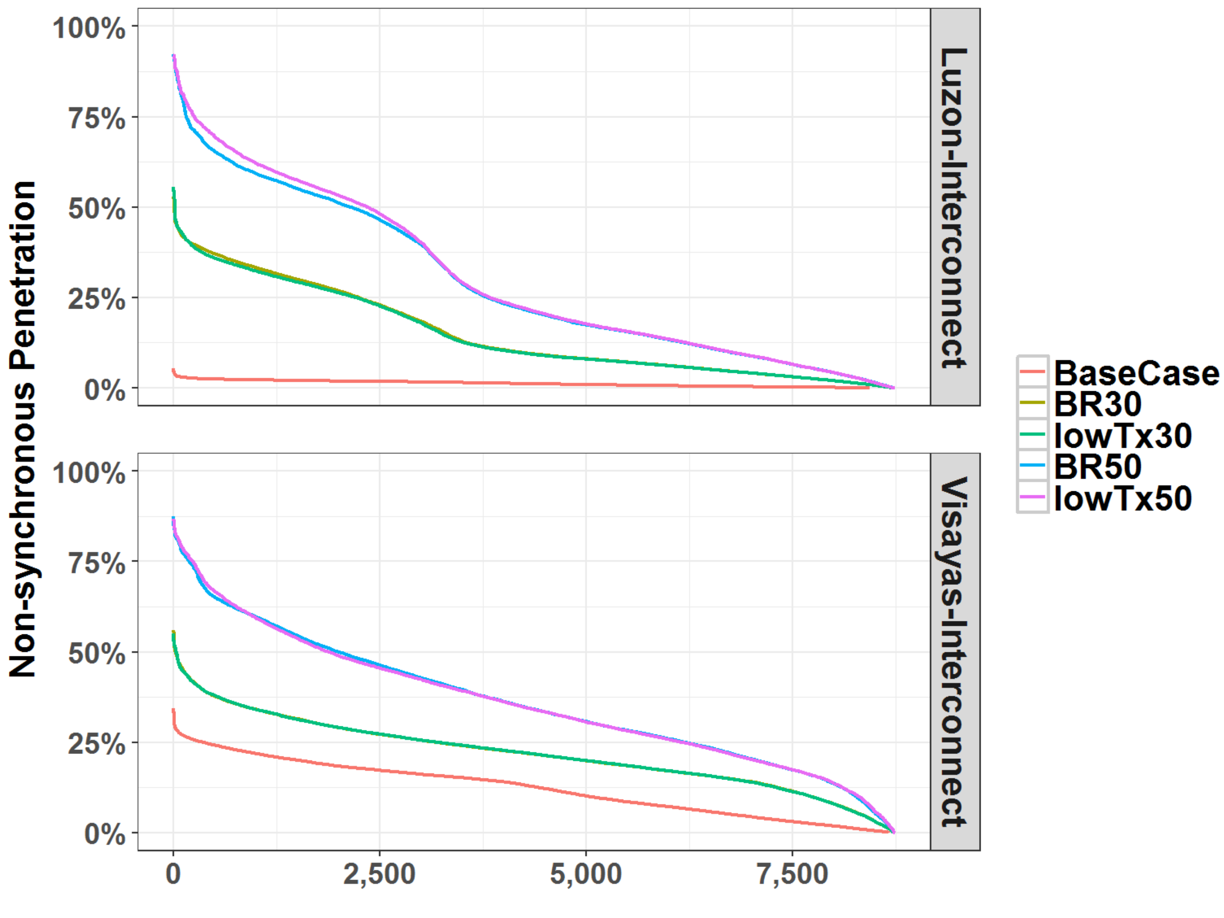


Figure 44. Non-synchronous penetration duration curve

As shown in Figure 44, some periods, especially in the 50% RE scenarios, will experience very high penetrations on non-synchronous generation. Power systems around the world have historically relied on synchronous generators to enable the system to recover in the event of a disturbance such as a large plant or generator outage. High levels of non-synchronous penetration may be a concern if non-synchronous generators such as wind turbines and solar panels are not equipped with the appropriate technologies to support system recovery. No universal standard for the appropriate level of non-synchronous penetration exists. Rather, NGCP would need to determine this threshold in the context of achieving its reliability goals for the power system. For each of the 2030 scenarios, selecting the hours in which non-synchronous penetration is very high in one or both grids can serve as a starting point for load flow analysis.

Modern solar and wind technologies are able to provide grid services such as frequency response and can contribute to contingency response (California ISO 2017, Milligan et al. 2015). Deploying these capabilities on new variable RE generators can help mitigate concerns surrounding non-synchronous penetration.

5 Summary and Implications for Decision Makers

Based on the results detailed in the previous section, the discussion below synthesizes five key findings of this study. Each finding is associated with one or more implications for Philippine power sector policymakers, regulators, and system and market operators.

Finding 1: RE targets of 30% and 50% are achievable in the power system as planned for 2030. Achieving these high RE targets will likely involve changes to how the power system is operated.

- ***Implication: The generation and transmission capacity expansion currently planned through 2030 will aid the integration of variable RE and will likely resolve some of the integration-related issues that have been observed since 2014.***

  This study did not find a technical limit to RE penetration: The modeled 2030 Luzon-Visayas system can balance all four high RE scenarios on an hourly basis. Further power flow, contingency, and system dynamic analysis is required to verify system balancing capabilities under high RE penetrations. However, this finding indicates that the planned 2030 system has the technical capability to reach a 50% RE target, even when the majority of this RE (up to 37%) comes from variable solar and wind.

  Importantly, all modeled 2030 scenarios assume the addition of generation and transmission capacity based on existing power sector development plans outlined by DOE and NGCP. These additions represent significant expansion beyond the power system infrastructure that exists today, and these investments are crucial to addressing many of the concerns that emerged in between 2014 and 2016 regarding the addition of significant solar and wind generation to the Luzon-Visayas system. For example, solar energy curtailments have occurred on the island of Negros in 2016. These curtailments have been attributed to the significant, rapid development of solar coupled with limitations in transmission capacity and ties with neighboring islands (NGCP 2015; Publicover 2016; Velasco 2016). In this study, neither the 2030 Base Case nor the high RE scenarios exhibit major solar curtailments in Negros. While the MWG did not conduct a sensitivity analysis specifically to assess the impacts of adding any particular transmission element, new infrastructure such as the Cebu-Negros-Panay 230-kV transmission backbone will very likely play an important role in mitigating the congestion and curtailment issues that occurred in 2016.

  This study makes the necessary scope-limiting assumption that the planned 2030 transmission system is realized. In reality, uncertainty surrounds the realization of many transmission developments. Because the modeled 2030 transmission system (which is constant across all 2030 scenarios) has been designed to meet the peak demand projected for 2030, the failure to realize one or many of the assumed transmission system enhancements could affect the overall ability of the system to balance not only the high RE scenarios but also the 2030 Base Case itself.

- ***Implication: Achieving high levels of variable RE will require an evolution in power system operation, especially the operation of conventional thermal generators.***

  In the 2030 scenarios, variable RE displaces generation primarily from coal and natural gas, leading to an 18%–40% reduction in thermal fuel consumption and a 19%–41% reduction in greenhouse gas emissions relative to the Base Case. In addition, because of the increased variability associated with higher levels of variable RE, the 30% and 50% RE scenario results show several operational changes relative to the Base Case: Conventional generators (especially coal and natural gas) start and stop more frequently, spend more time at their minimum stable output levels, and experience more significant ramps. Import and export patterns between the Luzon and Visayas grids also shift as RE penetrations increase. These changes are most significant in the 50% RE scenarios.

Finding 2: System flexibility will contribute to cost-effective integration of variable RE.

- ***Implication: Power sector decision makers can achieve multiple objectives—including low-cost, low-carbon, resilient, and reliable electricity production—by targeting system flexibility in operations and planning procedures.***

  The operational changes associated with the high RE scenarios highlight the crucial role of power sector flexibility in achieving significant levels of variable RE on the grid. The core high RE scenarios in this study do not assume any additional investments in flexibility beyond the implementation of planned new generation and transmission capacity described above.[22] For example, additional transmission capacity beyond the existing plans, while beneficial, is not necessary to achieve the 30% or 50% RE penetrations in the modeled power system. The modeled power system is able to achieve 30% and 50% RE penetrations because the Luzon-Visayas system is inherently somewhat flexible. Accessing this inherent flexibility will become essential for balancing the Luzon-Visayas system as variable RE penetration increases. This study models the physical capabilities of the generation fleet and transmission infrastructure to balance a variable net load. Access to this physical flexibility could be limited by institutional mechanisms, which are not fully modeled. For example, the Philippine electricity system currently requires generators to schedule their availability (generator on/off status) instead of centrally optimizing the system-wide unit-commitment schedule. This divergence between existing operational practices and the model representation may result in less flexible behavior than is exhibited by generators in the model.

  Enabling the flexibility required to achieve high levels of solar and wind generation likely involves a balance between changing institutional practices and making capital investments. Furthermore, the Luzon-Visayas system may require additional sources of flexibility to manage sub-hourly balancing and achieve reliable system operations. Beyond enabling the integration of solar and wind generation, flexibility is a critical component of overall electricity sector modernization and benefits the objectives of the Philippine power sector, including improved reliability and resilience, diversification of energy sources, reduced environmental impacts, utilization of indigenous resources, and reduced cost to the consumer.

  Numerous options are available to improve the flexibility of the Philippine power system. The sensitivity analyses in this study specifically tested two of these options (more flexible conventional generators and additional transmission capacity); others include solar and wind power forecasting, demand response, and storage. *Accessing and utilizing the flexibility of existing resources* likely represents the most cost-effective initial pathway to enabling the efficient integration of variable RE, including the solar and wind generation already committed in the next 5 years, as well as additional capacity.

  While a full assessment of the institutional and operational barriers to accessing flexibility in the Philippine power system is beyond the scope of this study, the implications below provide a variety of options for accessing existing power system flexibility. The Philippine power sector is also already implementing or planning several other actions that will enhance flexibility in the near term, including faster market scheduling intervals, solar and wind forecasting, and an ancillary services market. Over the longer term, additional investments in transmission, demand response, and storage

[22] As discussed in Section 2, the high RE scenarios add new variable RE capacity to the generation fleet planned for 2030. These scenarios do not replace Base Case generation capacity with solar and wind generation capacity nor do they assume any retirements to the 2014 Reference Case capacity. We recognize that this method represents a simplification relative to actual power sector planning in the Philippines, which would better optimize the future fuel mix. Generation capacity is one factor that impacts the need for power system flexibility and reserves. Future studies can better assess the sensitivity of the results presented in this report to assumptions about the 2030 fuel mix.

will help to ease integration issues, especially if the Philippines seeks to enable very high levels of variable RE (e.g., a 50% RE target).

- ***Implication: Comprehensive regulations and capacity procurement strategies may be required to encourage the procurement and operation of flexible assets.***

  At high penetrations, variable RE will necessitate more flexible operation of the conventional generation fleet than occurs in the current system. As the Philippines establishes its new ancillary services markets, an opportunity exists to define products that encourage flexible generation and provide new revenue sources for flexible conventional generators.[23] Additional options to improve existing conventional generator flexibility include retrofits to existing units to enable faster ramping, shorter startup and downtimes, and lower minimum stable levels.

  For new generation assets, selecting the most flexible technologies (e.g., natural gas and hydropower) and, regardless of technology, requiring new generators to implement the most flexible possible configurations will help achieve a modern and responsive fleet that can meet a variety of goals. System flexibility can also be improved through several technologies (many of which the Philippines is already implementing) that were not explicitly analyzed in this study, including: demand response, energy storage, improved forecasting, and intra-hour dispatch. Power sector planners can weigh the costs and benefits of these various resources in future capacity expansion planning efforts.

  Finally, solar and wind generators themselves can contribute to power system flexibility and reliability. The findings below discuss opportunities related to encouraging services from variable RE.

- ***Implication: Adopting best practices for reliable and efficient power system operations will help to integrate variable RE resources.***

  Wide area system scheduling, improved forecasting (load and variable RE), multiple scheduling horizons (day-ahead, intra-day, and real-time), sub-hourly scheduling intervals, dynamic reserve requirements, and centralized co-optimal unit commitment, economic dispatch, and reserves scheduling are all examples of operational practices that can help integrate variable RE resources. Several recent and ongoing Philippine power sector initiatives have made steps toward adopting these best practices. For example, NGCP recently implemented a wind and solar power forecasting program, and PEMC is adding sub-hourly resolution to the WESM and will soon open ancillary service markets that will enable the co-optimization of energy and tertiary reserves scheduling. Flexibility may be further enhanced by expanding the market to co-optimize the scheduling of energy and all operational reserve products (including primary and secondary reserves).

Finding 3: Achieving high levels of solar and wind integration will require coordinated planning of generation and transmission development.

- ***Implication: Strategically siting solar and wind generation can reduce the need for transmission investments beyond those already planned.***

  At 30% RE penetration, the differences between the modeled results of the BR and lowTx scenarios are negligible for most metrics, even though RE generator siting (particularly for solar) differs substantially in the two scenarios. This result, coupled with the relatively low (<2%) curtailment in both scenarios, implies that the 2030 power system is flexible enough to manage the impacts when variable RE resources are distributed across the power system based on either approach to RE siting. However, at 50% RE penetration, the differences between the results of BR and lowTx scenarios

[23] For example, the California Independent System Operator is operationalizing a "flexible ramping product" that is helping to manage variability of solar and wind generation in that system (California ISO 2015).

become more pronounced. Perhaps most notably, curtailment in the BR scenario (7.6%) is significantly higher than the lowTx scenario (4.4%). Driven at least in part by these higher levels of variable RE curtailment, variable costs and thermal fuel consumption are 1.4% and 1.7% higher in the BR50 scenario relative to the lowTx50 scenario, respectively.

Based on these results, strategically siting solar and wind generation can reduce the need for transmission investments that would otherwise be needed to reduce congestion and curtailment, especially at very high (e.g., 50%) RE penetrations. One approach to strategic siting is to establish capacity installation limits for certain geographic regions, for example, using the method applied in the lowTx scenarios, which defines zone-specific solar and wind capacity limits based on RE resources relative to transmission availability and load. This approach favors solar and wind in areas with high-quality RE resources and high levels of both load and transmission (e.g., NL-D3 and SL-D1), which maximizes the local consumption of variable RE and helps mitigate curtailment due to insufficient inter-zonal transmission. It also prevents potential overdevelopment of RE in regions that do not (and will not) have sufficient local consumption or transmission to efficiently use the RE generation locally (e.g., NL-D1, NL-D2, NL-D4, and Panay).

A rigorous power system planning process that balances the tradeoffs between renewable resource quality, access to transmission, and land access will help ensure the reliability and efficiency of future system operations. It will also help manage the cost of electricity, which depends in part on the location of generating capacity relative to transmission: If congestion occurs because generators are located in areas with limited transmission capacity, more expensive generating facilities would need to be dispatched to meet demand. Philippine power sector planners can further evaluate different approaches to siting new RE resources through capacity expansion modeling activities, which provide insight into development trajectories and guide policy design to achieve the desired outcome.

- ***Implication: Additional strategic investments in transmission infrastructure can help enable the lowest-cost solar and wind resource integration.***

  The results of the lowTx50 scenario indicates that the Philippines can achieve high RE levels while minimizing issues such as transmission congestion by encouraging solar and wind development in robust areas of the planned 2030 transmission system. This approach helps maximize the utilization of the planned 2030 system and reduce the need for additional grid enhancements. However, recognizing that the Philippine transmission planning process is dynamic and will likely involve numerous iterations between the publication of this study and 2030, our results also highlight the opportunity to utilize available resources in the country by upgrading or expanding the transmission system.

  The BR scenarios identified several zones that are home to some of the Philippines' highest-quality RE resources but where planned transmission may be insufficient to utilize these resources to their fullest potential (i.e., more restrictive solar and/or wind capacity limits were imposed in these zones in the lowTx scenarios in order to reduce local curtailment). In particular, these zones include areas of northern Luzon (especially NL-D1, NL-D2, and NL-D4), where the capacity factors of solar and wind are among the highest in the country. Transmission constraints also may limit the utilization of excellent RE resources in areas of southern Luzon and Visayas. When the transmission flow limits of 22 congested lines in these locations are increased by 50% above their original rated capacities to simulate the impacts of additional transmission capacity, RE curtailment in the BR50 scenario falls from 7.8% to 3.8%. RE resources with high capacity factors will produce more energy, lowering the cost per megawatt-hour of generating solar and wind resources. Strategic transmission investments—through transmission expansion or upgrades—that enable the energy delivery from areas where high quality RE resource can be developed will therefore enable more cost-efficient integration of RE resources in the Philippines.

To improve the ability of the Philippine power system to take advantage of the country's lowest-cost indigenous solar and wind resources, power system planners can consider more closely coordinating the clean energy generation and transmission system planning processes. One model for this type of integrated planning is the Competitive RE Zones (CREZ) approach, which the Texas power system implemented with the goal of planning transmission expansion to high wind energy resource areas. This approach involves identifying "RE zones," which are geographic areas characterized by a combination of high quality, abundant RE resources, suitable topography for RE project development, and strong private sector interest in developing these resources. The integrated clean energy and transmission planning process customizes the traditional transmission planning and approval process to direct transmission enhancements to these RE-rich regions (Hurlbut et al. 2016). Exploring this type of planning process may be a useful area for future work for Philippine power sector decision makers.

Finding 4: Strategic, economic curtailments of solar and wind energy can enhance system flexibility.

- ***Implication: Updates to existing policies, regulations, and practices may be required to facilitate minimal strategic curtailment of solar and wind generation to support flexible, economic power system operation.***

  Solar and wind curtailment occurs in all high RE scenarios (though at different levels—less than 2% in both 30% RE scenarios and 4.4% and 7.6% in the 50% RE lowTx and BR, respectively). Curtailment has several drivers, including:

  - Transmission flow limits: The transmission sensitivity analysis on the BR50 indicates that curtailment drops from 7.6% to 1.8% when all transmission flow limits are relaxed.
  - Generator flexibility: Particularly in the 50% RE scenarios, curtailment occurs during midday (peak generation from solar) when relatively inflexible generators such as coal and geothermal cannot be turned off and restarted quickly enough to meet demand after the sun sets. The need to operate these generators at their minimum stable output levels prevents the further utilization of solar and wind energy during the day.
  - Startup and shutdown costs: In some cases, the cost of stopping and restarting conventional generators may exceed the fuel cost savings associated with using all available solar and wind generation. In this case, curtailment is the most economic option.

  Minimizing curtailment is an important step towards lowering the cost of operating the power system and can help address stakeholder concerns regarding revenue sufficiency of RE generators. However, curtailment need not be zero for successful solar and wind integration; in fact, strategic curtailment is an important tool that the power system operator can draw upon to support flexible, economic power system operation, without investing in the generation and transmission infrastructure necessary to eliminate curtailment.

  The production cost model underlying this study allows solar and wind to be curtailed as part of the unit commitment optimization; we do not impose must-run constraints on solar, wind, or any other generator but instead allow the model to choose the least-cost dispatch within the physical constraints of the system. This approach differs from current Philippine system operations because of the laws and associated regulations that mandate preferential dispatch of solar and wind generators (along with other RE). In current market operations, RE generators provide their forecasts to the market operator, which then schedules these capacities for dispatch. Although NGCP can curtail solar and wind generation for reliability reasons, these laws and regulations prevent the *economic* curtailment of solar and wind generation. In many cases, utilizing all available RE in accordance with preferential dispatch requirements is the most economic option because the marginal costs of solar and wind are zero. However, in some cases, the most economically efficient operating point can result in RE curtailment, even when RE submits the lowest marginal cost generation bid, relative to other market participants. This situation can occur when it is less expensive from a system perspective to operate a coal generator at its minimum stable output level instead of stopping and restarting the generator to allow RE to be fully utilized. Thus, under preferential dispatch, the market settlements may not achieve the most efficient schedule.

As the Philippines increases the penetration of variable RE on the power system, economic curtailment of solar and wind generation may become an increasingly important source of power system flexibility. Enabling strategic, economic curtailment may involve reviewing and, if necessary, revising laws, rules, and operational practices that mandate preferential RE dispatch. It may also involve updating power supply agreements with solar and wind generators to enable economic as well as reliability-related curtailment by the power system operator.

Finding 5: Reserve provision may become an issue regardless of RE penetration. Additional QFs, including from solar and wind generators, and/or enhanced sharing of ancillary services between the Luzon and Visayas interconnections will likely be needed.

- ***Implication: When planning for new generation capacity, prioritizing fast-acting, flexible resources can support reserve and system balancing requirements.***

  Qualifying more generators to provide ancillary services and enhancing the capability to share reserves across the HVDC underwater cable will help reduce reserve shortages in 2030. The definition of reserve requirements and the ability of QFs to provide fast-response capabilities will help ensure reliable system operations and enable variable RE integration. Thus, procuring and/or accessing flexible capabilities of conventional generators will be crucial to meeting high RE goals. Furthermore, broadening generation planning to consider not only forecasted peak demand but also the necessary flexibility to respond to net load variability will help create a framework in which these procurement decisions can be evaluated.

- ***Implication: New or updated institutional measures may be needed to encourage variable RE generators (solar PV and wind turbines) to implement technical capabilities to provide a variety of reserves.***

  Wind turbines and solar PV generators can be equipped with technologies that enable them to provide downward reserves through AGC. Through recent technology advancements, variable RE can contribute additional ancillary reserve capabilities, such as synthetic inertia, frequency response, regulation up and down, voltage control, and active power management. The implementation of these technologies, especially in combination with NGCP's implementation of solar and wind power forecasting, can enable solar and wind generators to help supply grid services. Beyond the automatic variable RE curtailment currently allowed by the Philippine Grid Code for reliability reasons, new or updated regulations, contractual mechanisms, and ancillary service market product design can encourage these capabilities.

6 Conclusions and Opportunities for Further Study

RE, including variable resources such as solar and wind, will play an important role in achieving the government of the Philippines' vision for sustainable, stable, sufficient, accessible, and affordable energy. As the capital costs of solar and wind technologies continue to fall, the economic deployment of these abundant resources will become increasingly possible. Proactively planning for higher penetrations of variable RE will help to prepare the grid for the increased variability and uncertainty associated with these technologies, while also supporting the development of a more flexible, modern power system.

This study seeks to support such planning by simulating the hourly operation of the Luzon-Visayas system under various high RE scenarios, identifying potential technical concerns associated with these scenarios and potential options to improve cost-effective integration. The results indicate that annual RE penetrations of 30% and 50% based predominantly on generation from variable RE are achievable by 2030, assuming the planned evolution of the power system takes place. This planned evolution includes additions to both generation and transmission capacity beyond what existed in 2016. Achieving very high levels of solar and wind energy production will have a significant impact on the operation of the power system. The Philippines is already planning and/or implementing several activities that will enhance the flexibility of the Luzon-Visayas system to efficiently balance high levels of variable RE, and this study provides insights on additional options to access or improve power system flexibility.

While this study provides an initial indication that there are no fundamental technical barriers to achieving 30% or 50% RE, additional studies are needed to assess the reliability of the Luzon-Visayas system at these high penetrations (especially during the hours identified in this study in which very high penetrations of non-synchronous generation occur). Analysis of reliability, including voltage, stability, and recovery, is beyond the scope of this production cost modeling study. Assessing these issues via AC power flow simulations is a crucial area for follow-on work.

This study evaluated only the costs of operating the power system under different RE scenarios but did not study the capital costs of constructing the transmission and generation in each scenario. Conducting capacity expansion modeling that considers capital costs and optimizes the fuel mix based on cost and policy priorities is a valuable area for follow-on work and essential to understanding the broader economic implications of various future scenarios beyond operational costs. Capacity expansion analysis can simulate the siting and proportion of solar and wind generation in the power mix, rather than analyzing "snapshot" scenarios, as is the case in this study. It can also compare the effectiveness and cost of all energy resources to meet demand and reserve requirements under different policy, capital cost, and fuel price scenarios.

This study is intended to provide a long-term outlook but should not replace the normal short- and mid-term power sector planning processes that DOE, NGCP, and others undertake on a regular basis. These processes may provide an appropriate forum to continuously update assumptions (e.g., on-demand growth and spatial distribution and future fuel prices) both in the production cost model developed for this study and in the other analyses that support system planning. Many opportunities exist to expand and update the production cost analysis pioneered in this study, including:

- Expanding the scope of the analysis to Mindanao
- Simulating intra-hourly balancing (this would require sub-hourly solar, wind, and load data, which is not readily available at the time of this study)
- Considering the impacts of embedded RE generation (i.e., rooftop solar PV connected to the distribution grid)
- Simulating the impact of adding demand response and/or battery energy storage systems
- Testing different market tariff and market participant behavior assumptions (including must-run versus dispatchable generation)

- Testing different generation and transmission planning assumptions (including the realization of different electric sector planning scenarios).

Integrating high levels of variable RE requires an evolution in power system planning and operation. This study, along with the many opportunities for follow-on work identified above, can inform that evolution and contribute to the analytical basis for addressing the technical barriers to achieving a clean, reliable, and flexible Philippine power system.

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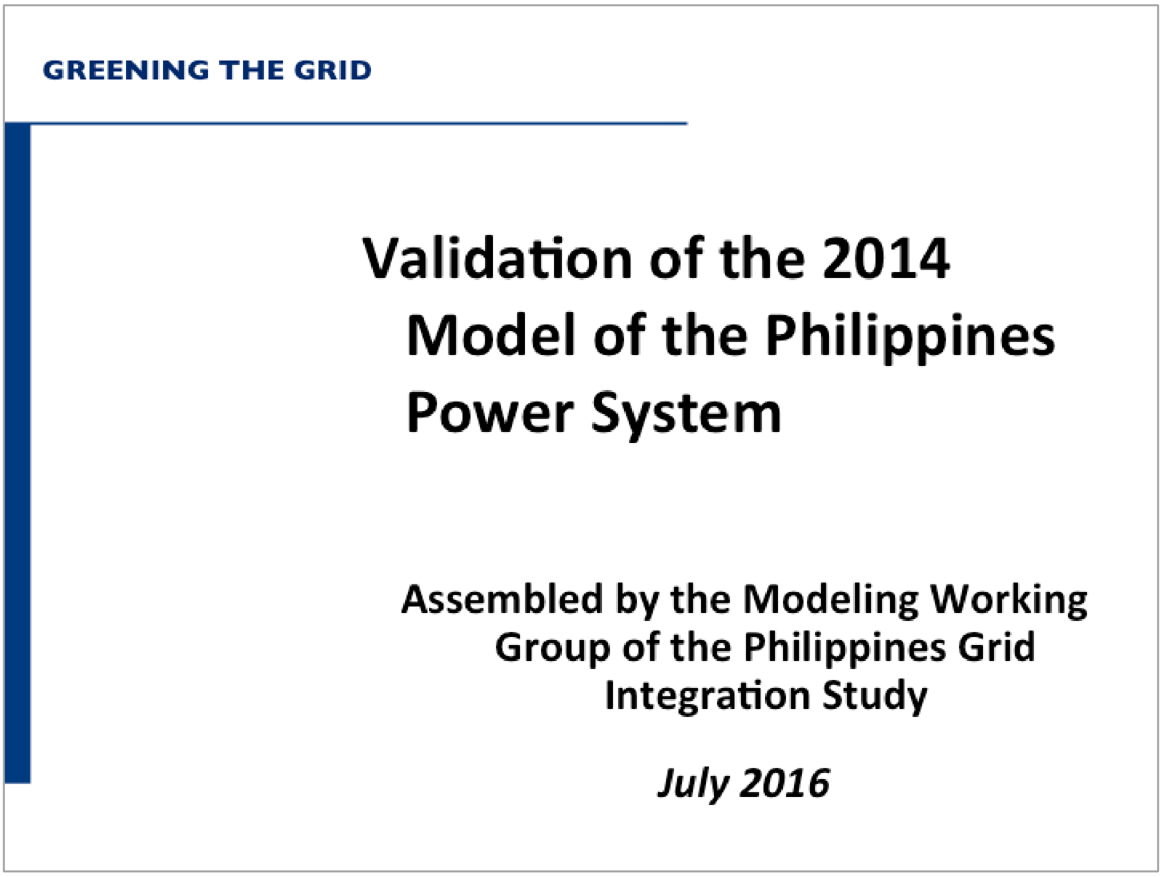
Appendix A: Overview and Validation of the 2014 Model of the Philippine Power System

The following presentation was delivered to the DOE TAC co-chairs in July 2014. These slides provide the results of the MWG's efforts to validate the 2014 Reference Case based on historical data.



Greening the Grid Partnership

The creation of the Technical Advisory Committee (TAC) and Modeling Working Group (MWG) will ***enable variable renewable energy (VRE) integration and installation targets. This goal shall be achieved through the conduct of a grid integration study…"***

-Department Circular No. DC 2015-11-0017

Co-Chairs:

Republic of the Philippines
DEPARTMENT OF ENERGY
(Kagawaran ng Enerhiya)

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Overview

- **This presentation is intended to support the examination and validation of the 2014 "reference case" PLEXOS model of the Philippine power system**
- **Outline:**
    - Purpose and process for developing the 2014 reference case
    - Key differences between modeled and actual operations in 2014
    - Comparison of modeled and actual statistics
    - Conclusions

2nd TAC Meeting – 3 June 2016

Seda BGC Hotel

Why do we need a reference case?

- The objective of the Greening the Grid study is to model the impacts of significant variable renewable energy on the 2030 Philippine power system.
- In order to have confidence in 2030 results, we need to test the model to make sure it produces realistic results compared with an actual year of operation—in this case, 2014.

How was the 2014 reference case developed?

- Significant team effort by the five agencies involved in the Modeling Working Group
- Non-disclosure agreement among the five MWG organizations to facilitate data sharing
- Each organization has made significant efforts to provide data and shape modeling assumptions
- Preliminary outputs vetted by the TAC (June 3) and separately by DOE principals (June 30)

Department of Energy (DOE)	Grid Management Committee (GMC)	National Grid Corporation of the Philippines (NGCP)	Philippine Electricity Market Corporation (PEMC)	National Renewable Energy Laboratory (NREL)

Data used for 2014 reference case	Source
Transmission network details	• NGCP operational planning PSS/E case • Lat/long for approximately 150 nodes
Hydro, geothermal, and seasonal biomass generation constraints	• Daily and monthly hydro and geothermal generation data from DOE • 2015 biomass offers from PEMC
Variable cost of generators	• Fuel and O&M costs based on monthly operations report to DOE • U.S. defaults for start costs
Time series (hourly) load data	• Hourly load for Luzon and Visayas provided by NGCP • Node-level load participation factors calculated based on PSS/E
Wind and solar generation in 2014	• Wind and solar resource profiles developed by NREL • Actual daily or hourly generation provided by DOE-REMB
Unit-level generator information • Maximum dependable capacity • Minimum stable level • Ramp rate • Heat rate (partial & full load)	• Provided by DOE • Cross-checked against PSS/E case and GMC feedback • Min up & down times based on India study defaults
Outages • Maintenance rate • Mean maintenance time • Forced outage Rate • Mean time to repair	• Generator maintenance and outage information by fuel type provided by GMC • Transmission forced outage data provided by NGCP
• Reserve requirements	• Historic and proposed reserve products, rules, and qualifying generators provided by NGCP

Validating the 2014 reference case

- **Goal for validation of 2014 model: "reasonable" representation of operations**
  - Annual generation by generator type
  - Plant capacity factors
  - System flexibility
  - General flow patterns
  - Outage rates
- **Our goal is not to model 2014 exactly as it happened, but rather to create a model that we have confidence will represent operations during a future year (i.e., 2030)**
  - We want to avoid "over-tuning" the model so that it represents only the specific circumstances of 2014 operations.

How does our model differ from the Philippine electricity market?

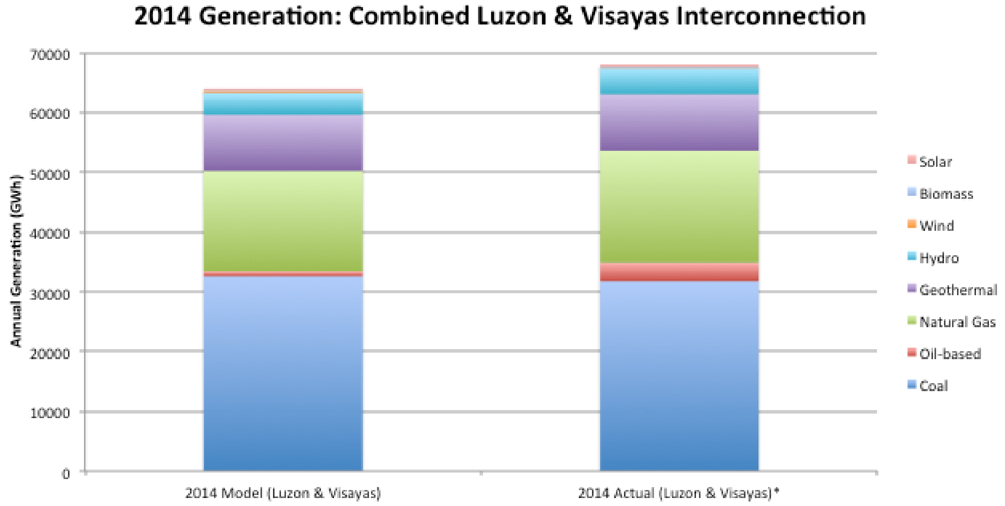
- The model does not capture:
  - Bidding behavior, including self-scheduling. Model assumes all generators bid their assumed marginal cost and capability.
  - Bilateral transactions
  - Must-run / reliability commitments or dispatch by operator
- Model applies constant hourly load participation factors for each interconnection
- Data on forced and maintenance outages only covers generating plants that have an aggregated capacity of 20 MW and above in accordance to ERC Resolution No. 17, Series of 2013
  - Variable Renewable Energy (VRE) Power Plants are not covered in the scope of Resolution No. 17

GREENING THE GRID

Comparison of Modeled and Actual Statistics for 2014

Annual Generation: Model vs. Actual

2014

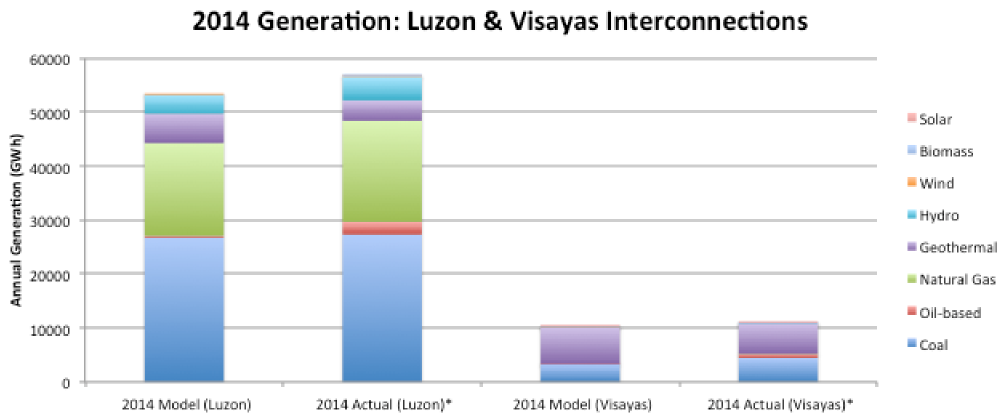


Luz + Vis	Solar	Biomass	Wind	Hydro	Geothermal	Natural Gas	Oil	Coal	Total
Model	<0.1%	0.2%	0.6%	5.7%	14.7%	26.3%	1.4%	51.1%	100%
Actual	<0.1%	0.3%	0.2%	6.5%	13.9%	27.6%	4.6%	46.9%	100%

*Source: 2014 Philippine Power Statistics. http://www.doe.gov.ph/doe_files/pdf/02_Energy_Statistics/power_statistics_2014.pdf.
Note: Actual 2014 data includes generation from grid connected, embedded, and off-grid generators.

Annual Generation by Region: Model vs. Actual

2014



Luzon	Solar	Biomass	Wind	Hydro	Geothermal	Natural Gas	Oil	Coal	Total
Model	0%	0%	0.7%	6.8%	6.7%	31.5%	1.6%	52.7%	100%
Actual	0%	0%	0.3%	7.7%	6.7%	32.9%	4.1%	48.2%	100%

Visayas	Solar	Biomass	Wind	Hydro	Geothermal	Natural Gas	Oil	Coal	Total
Model	0.2%	0.9%	<0.1%	0.3%	55.6%	0%	0.2%	42.7%	100%
Actual	0.1%	1.1%	0%	0.3%	51.1%	0%	7.0%	40.4%	100%

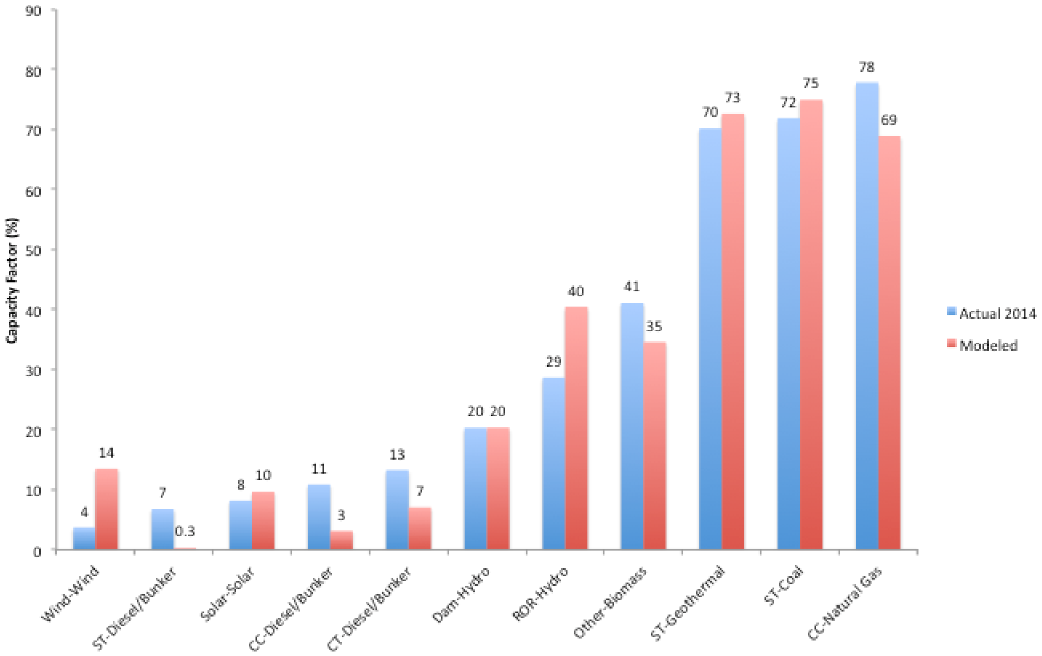
*Source: 2014 Philippine Power Statistics. http://www.doe.gov.ph/doe_files/pdf/02_Energy_Statistics/power_statistics_2014.pdf.
Note: Actual 2014 data includes generation from grid connected, embedded, and off-grid generators.

Observations: Annual Generation

- **Overall, relative generation by different fuel sources is *very similar* between the modeled output and actual data.**
  - Share of total annual generation for each fuel type deviates by <5% between the simulation results and actual generation.
- **Data on actual total generation in 2014 includes embedded and off-grid generators, which are not included in the model.**
  - This explains the difference in absolute generation, and could also partially account for the higher diesel generation observed in the actual data relative to the modeled results.
- **Other differences:**
  - Biomass is lower in the model than in reality because we have imposed seasonal fuel supply limitations for biomass.
  - Some curtailment of wind took place in 2014; because this energy was never generated, it is outside both actual and modeled 2014 data.

Generator Capacity Factors: Model vs. Actual

2014



Capacity factor calculation is based on maximum dependable capacity, not rated capacity. Actual 2014 data courtesy of DOE.

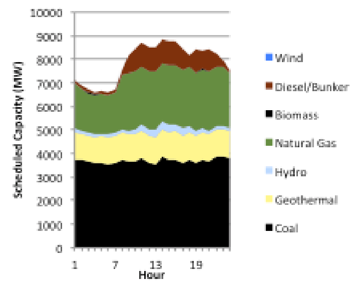
Observations: Capacity Factors

- **The relative magnitude of technology capacity factors is consistent between the model and actual operations.**
- **Capacity factors deviate by <10% between the simulation results and actual generation for almost all technologies.**
- **Potential causes for discrepancies:**
  - Incomplete actual generation data from 2014 to which to compare modeled outputs.
  - Differences between the model and the market (see slide 9), e.g., the model does not capture self-scheduling, bilateral transactions, or reliability commitments.
  - Biomass and wind: see slide 13. Some wind generation was curtailed in 2014. No curtailment occurs in the modeled solution, so the capacity factor of wind is higher in modeled results than it is in the actual 2014 statistics.

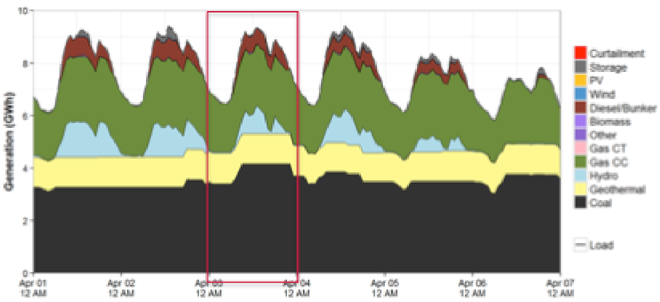
System dispatch

2014

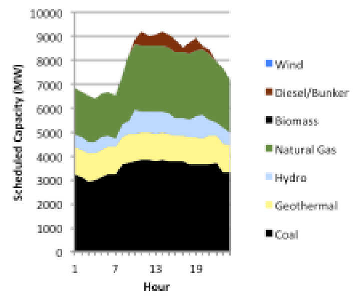
Actual Market Schedule (Apr 3, 2014)



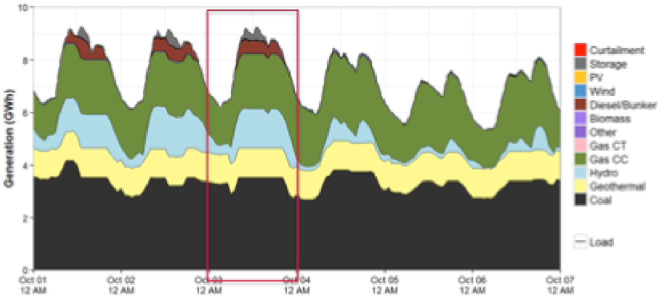
Modeled dispatch (April 1-7, 2014)



Actual Market Schedule (Oct 3, 2014)



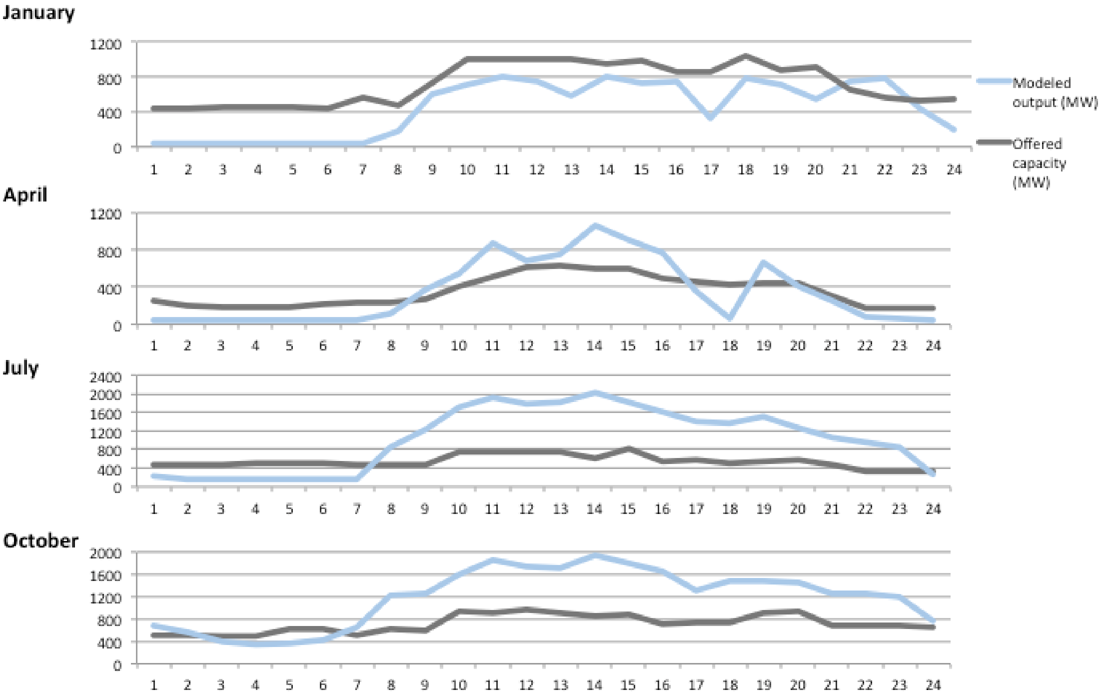
Modeled dispatch (October 1-7, 2014)



Actual market schedules courtesy of PEMC

Hydro dispatch (hourly; selected days)

2014

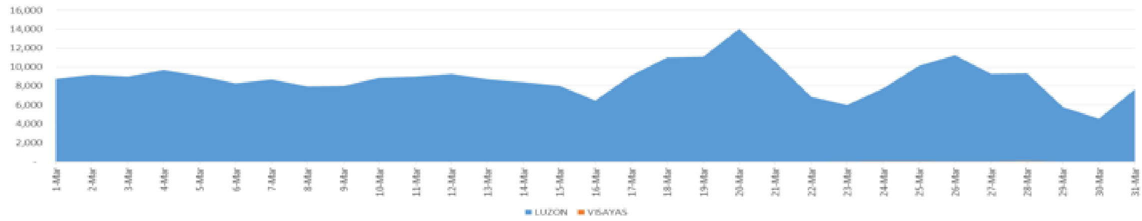


Actual hydro offer data courtesy of PEMC

Hydro Generation (Daily – March 2014)

2014

Actual, MWh hydro generation



Modeled, MWh hydro generation

Actual hydro generation data courtesy of DOE.

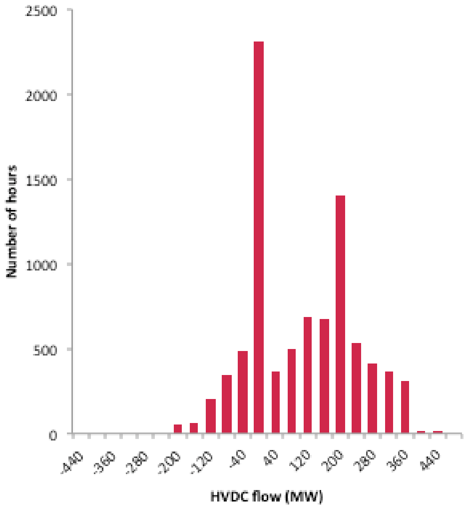
Observations: System Dispatch

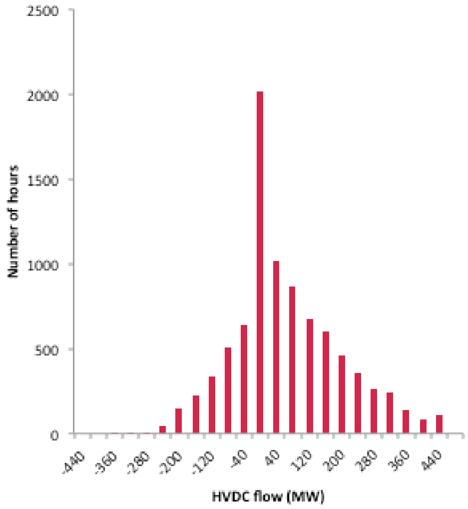
- **Coal is more flexible in the model than it is in reality**
  - Model reflects that every unit (including coal) bids its capability at marginal cost.
  - In reality, the market allows for self-schedule (for example, coal plants are self-committed).
  - While we could adjust the 2014 model to reflect self-scheduling, we have chosen not to because the transition to a 5-minute market before 2030 will effectively eliminate this issue.
- **Modeled hydro operations follow the pattern of actual operations at an hourly level.**
  - We are applying monthly hydro energy limits to capture seasonal constraints on hydro resource availability.
  - Further constraining daily or hourly hydro production might lead to over-tuning of the model.

Transmission flows: Luzon-Visayas HVDC interconnection

2014

Actual 2014 | **Modeled**





Positive values represent **flows *from* Visayas *to* Luzon**

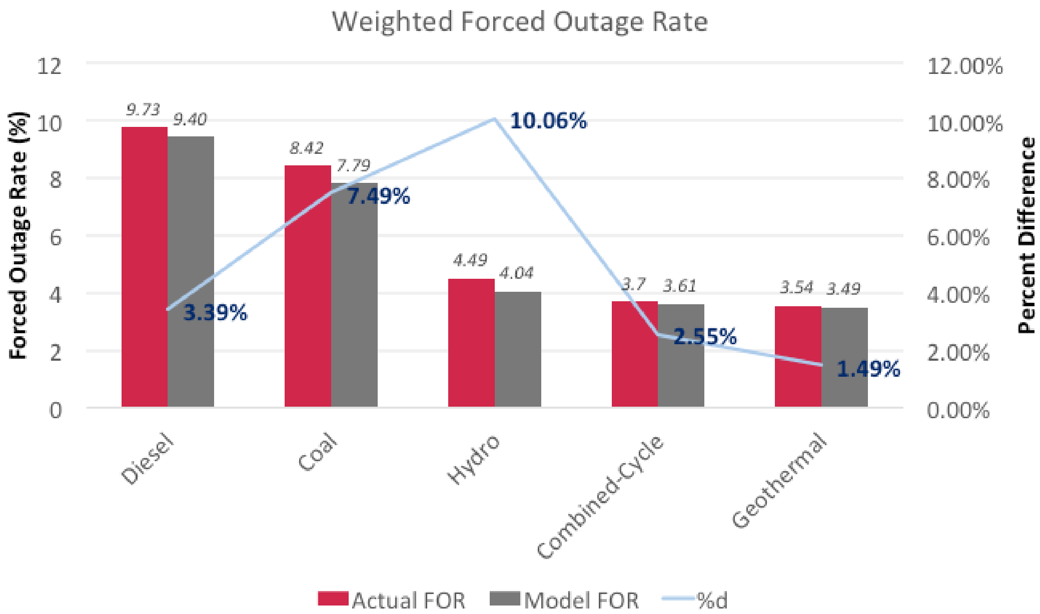
Actual HVDC flow data courtesy of NGCP

Observations: Transmission Flows

- **HVDC flow discrepancies are likely due to two issues:**
  - The WESM schedules HVDC flow based upon the difference between Luzon and Visayas net-load that results from a dispatch that differs from the PLEXOS simulation
  - The PLEXOS model does not capture the losses associated with the AC-DC-AC conversion of power
- **To capture friction imposed by these differences, we have applied a 'wheeling' charge to energy transfers across the HVDC line in the model**
  - The wheeling charge of 100 PHP/MWh results in flow patterns with a similar shape to the 2014 actual HVDC flows

2014

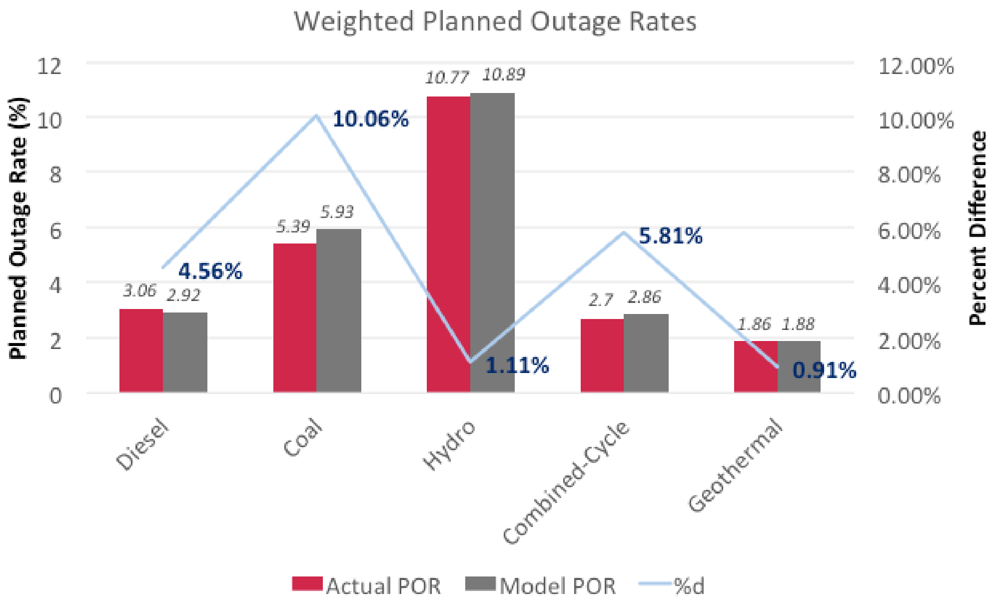
Forced Outage Rates Validation



Actual outage rate data courtesy of GMC

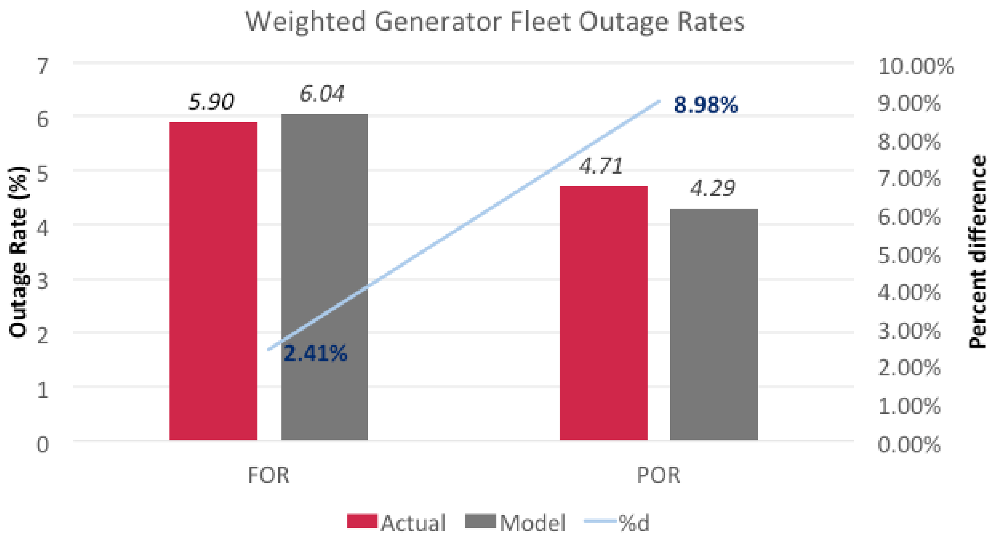
2014

Planned Outage Rates Validation



Actual outage rate data courtesy of GMC

Overall Generator Fleet Weighted OR Validation



Actual outage rate data courtesy of GMC

Observations: Generator outages

- **Forced and planned outages are consistent between model outputs and actual data.**
  - At the fleet level, the difference between modeled and actual forced outage rate is <3%. The difference between modeled and actual planned outage rate is <9%.
- **Sources of minor inconsistences:**
  - For each technology, GMC calculates *weighted* average forced and planned outage rate, taking into the consideration the size of each generator. PLEXOS does not apply any kind of weighting when it simulates outages.
  - 2014 outage data covers 72.15% of the total capacity of Luzon and Visayas grids (9,752 MW out of 13,516 MW of LV Grids).
    - Future iterations will utilize 2015 outage data, which covers >90% of total capacity.
    - Future iterations will also likely utilize *Equivalent* Forced Outage Rate (EFOR) instead of the standard Forced Outage Rate (FOR). EFOR considers derating hours, which are converted to equivalent outage hours and supplemented to the computation of FOR to arrive at a value of EFOR.

Conclusions

Though there are differences between 2014 modeled output and actual 2014 operations, the MWG has *high confidence* that the 2014 reference case well represents capabilities and limitations of the Philippine power system and recommends moving forward with using this model as the basis for 2030 analysis.

Classification of ancillary services used in 2014

2014

Currently modeled

OLD					
NAME	CONTROL MODE	AMOUNT	PERFORMANCE REQUIREMENT		
			Reaction	Saturation	Sustainability
Frequency Regulating Reserve	Primary Response: **FGM**	4% of the system demand	within 5 seconds	none	25 seconds
	Secondary Response: **AGC**		within 25 seconds	none	at least 30 minutes
Contingency Reserve	Primary Response: **FGM**	Load of the largest unit online	none	10 minutes	none
	Secondary Response: **AGC/Manual**		none	10 minutes	at least 30 minutes
Dispatchable Reserve	Manual	Load of the second largest unit online	synchronize within 15 minutes	none	at least 8 hours

Appendix B: Wind Resource Data Set Development

Wind resource assessment in this project was limited by the data available and required the integration of two data sets. The first was the 2014 Wind Atlas for the Philippines developed by NREL.[24] The Wind Atlas is a TMY data set, which provides high spatial resolution (~1 km) wind resource data at hourly time intervals. The TMY data were created from a 15-year forced sampling based on a numerical weather prediction model. The data set was a mosaic of daily time intervals (of hourly data) from across the 15-year sample period, which aimed to capture inter-annual variability and estimate the long-term expected wind resource (i.e., expected wind speed). However, the assembly of the TMY data created "seams" in the time series where data from different years were placed in adjacent time periods, as shown in Figure 45. Additionally, the time series was constructed from daylong time periods from multiple years and thus was not temporally synchronized with the 2014 system load data. These two limitations made the TMY data inappropriate for production cost modeling.

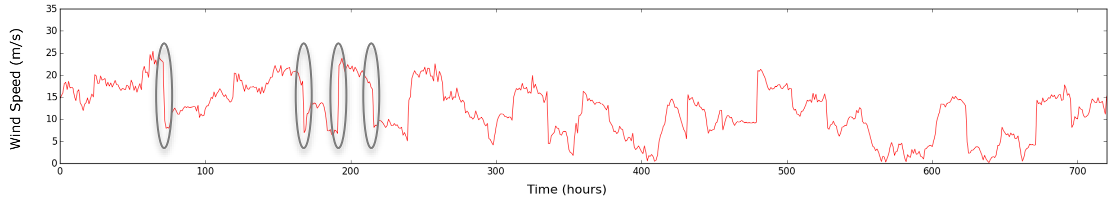


Figure 45. A time slice of one month from the hourly TMY data set is shown in red. Examples of prominent "seams" between mosaicked days are shown with gray ovals.

The second data source was a 2014 hourly wind resource data set, made available by the Aarhus University in Denmark (Andresen et al. 2015), which is based on global reanalysis of data from the U.S. National Centers for Environmental Protection. The 2014 data set is time-synchronous with the load data, but the spatial resolution (~30 km) is too coarse to model wind resource potential. To overcome the limitations of each data set, NREL blended the Wind Atlas TMY data with the Aarhus University 2014 data set to produce a high spatial resolution data set that captured the long-term resource availability, while being temporally synchronized with the 2014 load data.

B.1 Data Set Blending Methodology

The algorithm developed by NREL to integrate the two data sets aimed to capture four components:

1. Magnitude—measured as area under the curve (AUC)—of long-term wind potential represented by the Wind Atlas TMY data set
2. The spatial variability of wind resource captured at 1-km spatial resolution by the TMY Wind Atlas data set
3. The distributional properties of the Aarhus University 2014 data set, which followed a Weibull distribution
4. The time-synchronicity of the Aarhus University 2014 data set with the load data.

The approach was a two-step algorithm, where each Wind Atlas TMY data set location was first associated with an Aarhus University 2014 data set location. Then the two profiles were blended using a moving window operation. Around each Wind Atlas TMY data set location, an 80-km circular buffer was drawn to isolate the closest Aarhus University 2014 data set locations. Then, the Aarhus University 2014 data set location with the most similar mean annual wind speed to that of the TMY location was selected. This approach associated the two profiles based on both distance and wind resource quality. The buffer distance was chosen after examining varied distances from 40 km to 200 km. The 80-km buffer distance provided a balance between minimizing the spatial separation of locations and the difference between mean annual wind speeds. In the second step, the Wind Atlas TMY profile was first smoothed using a Gaussian filter to reduce the influence of the TMY variability in the subsequent

[24] For more information, see http://www.nrel.gov/international/ra_philippines.html.

blending method. Because the variability in the Wind Atlas TMY data set was not time-synchronous with the load data, filtering removed short-term variability while preserving the overall magnitude (AUC) of the wind resource.

The blending algorithm was a moving window operation that scaled the Aarhus University 2014 profile to approximate the area under the curve of the Wind Atlas TMY profile, while forcing the values of the Aarhus University 2014 profile to fall within the range of the smoothed TMY values. First, the Aarhus University 2014 profile was scaled to a range from 0 to 1. Then the profile was simply scaled up so the minimum and maximum values matched those of the Wind Atlas TMY profile (Figure 46). This moving window operation was conducted with a temporal overlap so that seams would not exist between windows in the time series. The width of the moving window was 48 hours, and the overlap was half of that. Overlapping values were averaged to remove seams. The window width was selected to match the AUC of the TMY profile as closely as possible based on a sample subset of sites.

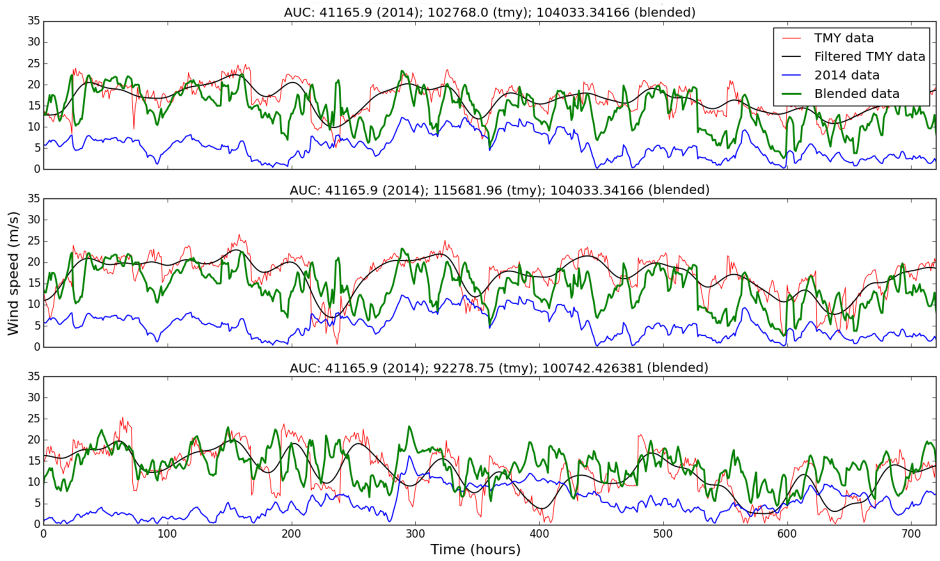


Figure 46. Profiles from the blending method for three sample sites in Luzon are shown across one month.

The Wind Atlas TMY profile (red) was first smoothed with the Gaussian filter, and then the Aarhus University 2014 profile (blue) was scaled to the filtered Wind Atlas TMY profile (black), resulting in the blended profile (green). AUC shown above each plot for the 2014, TMY, and blended profiles.

B.2 Outcome of the Profile-Blending Method

The blending approach was successful in capturing a balance of the four components that were desired from the two data sets. The filtered Wind Atlas TMY profile (black lines in Figure 46) captured the long-term AUC, and blending the Wind Atlas TMY site profiles provided at 1-km spatial resolution. By simply scaling the Aarhus University 2014 profiles, time-synchronicity with the load data was preserved as well as the distributional properties. In general, time-synchronous wind data tend to follow a Weibull distribution, while TMY data tend to have a bimodal nature. The blending method preserved the Weibull-distributed properties of the Aarhus University 2014 data (Figure 47). Given the limitation of data availability, the described methodology was effective in providing the high-resolution wind resource data needed for this project.

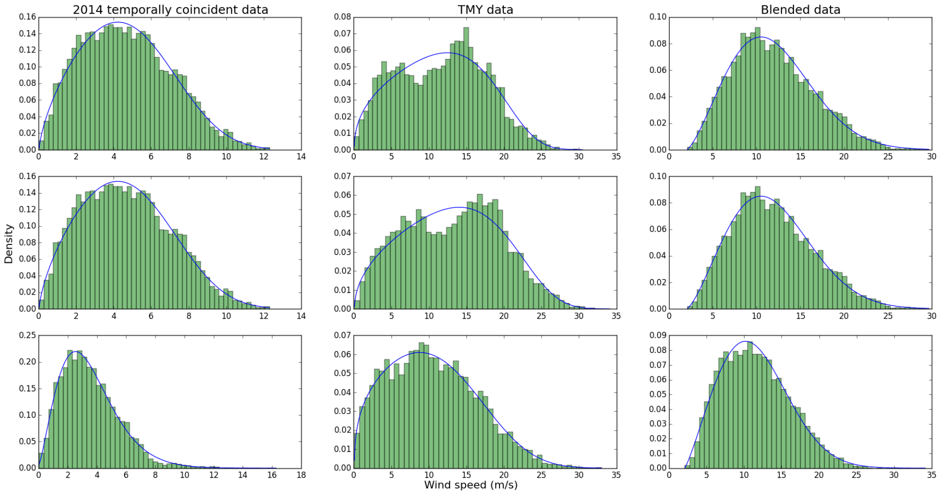


Figure 47. Histograms from the profiles for the three sample sites in Luzon (shown in Figure 46.

A Weibull distribution (blue line) was fit to each histogram.

Appendix C: Site Selection Parameters and Results

Table 17. Site Selection Parameters and Results

Zone	Inter-conn-ection	Peak Zonal Load	BR30					BR50					lowTx30					lowTx50				
			Maximum Installed Capacity Limit (Zonal Peak Load Multiplier)		Selected Capacity (MW)			Maximum Installed Capacity Limit (Zonal Peak Load Multiplier)		Selected Capacity (MW)			Maximum Installed Capacity Limit (Zonal Peak Load Multiplier)		Selected Capacity (MW)			Maximum Installed Capacity Limit (Zonal Peak Load Multiplier)		Selected Capacity (MW)		
			Solar	Wind	Solar	Wind	Total	Solar	Wind	Solar	Wind	Total	Solar	Wind	Solar	Wind	Total	Solar	Wind	Solar	Wind	Total
NL-D1	Luzon	298	4	4	900	33	933	4	4	900	111	1,011	3	0	600	33	633	1	0	239	88	327
NL-D2	Luzon	243	4	4	300		300	4	4	300		300	1	50	243	-	243	1	50	243	-	243
NL-D3	Luzon	744	4	4	2,700	25	2,725	4	4	2,700	68	2,768	10	50	6,300	25	6,325	9	50	6,300	65	6,365
NL-D4	Luzon	451	4	4	-	-	-	4	4	1,800	9	1,809	50	50	-	-	-	2	50	900	4	904
NL-D5	Luzon	766	4	4	1,200	26	1,226	4	4	1,800	83	1,883	50	50	-	26	26	50	50	1,800	77	1,877
NL-D6	Luzon	1,118	4	4	-	-	-	4	4	3,000	9	3,009	50	50	-	-	-	1	50	1,500	5	1,505
NL-D7	Luzon	242	4	4	-	156	156	4	4	900	237	1,137	50	50	-	156	156	50	50	-	230	230
BULACAN	Luzon	478	4	4	-	-	-	4	4	-	-	-	50	50	-	-	-	50	50	-	-	-
METRO-MANILA	Luzon	7,884	4	4	-	-	-	4	4	600	-	600	50	50	-	-	-	50	50	600	-	600
CAVITE	Luzon	674	4	4	-	27	27	4	4	-	290	290	50	50	-	27	27	50	50	-	258	258
LAGUNA	Luzon	1,792	4	4	-	-	-	4	4	-	5	5	50	50	-	-	-	50	50	-	5	5
BATANGAS	Luzon	101	4	4	-	-	-	4	4	-	-	-	50	50	-	-	-	50	50	-	-	-
SL-D1	Luzon	717	4	4	2,100	105	2,205	4	4	2,700	337	3,037	50	50	-	105	105	50	50	5,100	316	5,416
SL-D2	Luzon	227	4	4	-	466	466	4	4	900	908	1,808	50	50	-	466	466	50	50	-	1,041	1,041
SL-D3	Luzon	448	4	4	-	109	109	4	4	1,200	309	1,509	50	50	-	109	109	50	50	-	281	281
SAMAR	Visayas	105	2	2	-	171	171	2	2	-	210	210	50	50	-	171	171	50	50	-	377	377
LEYTE	Visayas	335	2	2	-	42	42	2	2	-	112	112	50	50	-	42	42	50	50	-	104	104
BOHOL	Visayas	127	2	2	-	23	23	2	2	-	38	38	50	50	-	23	23	50	50	-	34	34
CEBU	Visayas	1,449	2	2	-	27	27	2	2	-	81	81	50	50	-	27	27	50	50	-	71	71
NEGROS	Visayas	432	2	2	-	210	210	2	2	-	555	555	50	50	-	210	210	50	1	-	477	477
PANAY	Visayas	429	2	2	-	161	161	2	2	600	569	1,169	50	50	-	161	161	1	50	300	492	792
Total	-	19,058	-	-	7,200	1,581	8,781	-	-	17,400	3,931	21,331	-	-	7,143	1,581	8,724	-	-	16,982	3,925	20,907

Appendix D: Photo Documentation

Photo credits: Cover photo from Energy Development Corporation, showing Energy Development Corporation's Burgos Wind and Solar Project located at Burgos, Ilocos Norte, Philippines

1st Technical Advisory Committee (TAC) Meeting

Shangri-la Hotel Makati – 21 January 2016

Figure 48. MWG member Mary Grace Gabis (DOE) opens the meeting

Figure 49. Dr. Jaquelin Cochran (NREL) presents to the TAC

Figure 50. Director Mylene C. Capongcol provides remarks on behalf of DOE

2nd Technical Advisory Committee (TAC) Meeting

Seda Hotel Bonifacio Global City – 3 June 2016

Figure 51. Director Capongcol (DOE) provides opening remarks to the TAC

Figure 52. Question and answer session with the TAC

Figure 53. Members of the MWG

From left to right: Jessica Katz (NREL), Mary Grace Gabis (DOE), Kenneth Jack Muñoz (DOE), Dr. Clayton Barrows (NREL), Hanzel Cubangbang (NGCP), Jonathan de la Viña (PEMC), Noriel Christopher Reyes (DOE), Rommel Reyes (NGCP), Dr. Jennifer Leisch (USAID), and Mark Christian Marollano (DOE)

3rd Technical Advisory Committee (TAC) Meeting

University of the Philippines Bonifacio Global City (UP-BGC) – 2 February 2017

Figure 54. Dr. Clayton Barrows (NREL) addresses the members of the TAC

Figure 55. Attendees of the third TAC meeting

Figure 56. Members of the Greening the Grid MWG

From left to right: Rommel Reyes (NGCP), Hanzel Cubangbang (NGCP), Mark Christian Marollano (DOE-EPIMB), Jake Binayug (GMC), Nielson Asedillo (GMC), Undersecretary and incumbent TAC Chairperson Felix William Fuentebella (DOE), Jonathan dela Viña (PEMC), Dr. Clayton Barrows (NREL), Jessica Katz (NREL), Mary Grace Gabis (DOE-EPIMB), Kenneth Jack Muñoz (DOE-EPIMB), and Noriel Christopher Reyes (DOE-EPIMB)

Not pictured: Dr. Jaquelin Cochran (NREL), Clarita De Jesus (DOE-REMB), Edward Olmedo (PEMC), and Galen Maclaurin (NREL)

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