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COMMONWEALTH OF PUERTO RICO
PUBLIC SERVICE REGULATORY BOARD
PUERTO RICO ENERGY BUREAU

IN RE: LUMA RESOURCE ADEQUACY STUDY	**CASE NO.: NEPR-MI-2022-0002** SUBJECT: Motion to Submit Corrected Exhibit 1 of Motion to Submit LUMA's 2024 Resource Adequacy Study filed on November 14, 2023

MOTION TO SUBMIT CORRECTED EXHIBIT 1 OF THE MOTION TO SUBMIT LUMA'S 2024 RESOURCE ADEQUACY STUDY FILED ON NOVEMBER 14, 2023

TO THE HONORABLE PUERTO RICO ENERGY BUREAU:

COME NOW LUMA Energy, LLC and **LUMA Energy ServCo, LLC** (jointly referred to as "LUMA"), and, through the undersigned legal counsel, respectfully state and request the following:

1. On November 14, 2023, LUMA filed with the Puerto Rico Energy Bureau of the Public Service Regulatory Board ("Energy Bureau") a *Motion to Submit LUMA's 2024 Resource Adequacy Study* enclosing as Exhibit 1 (the "November 14 Exhibit") a document titled "Puerto Rico Electrical System Resource Adequacy Analysis" and dated November 14, 2023 ("2024 Resource Adequacy Study").

2. LUMA has become aware of the following two minor inadvertent typographical errors in the November 14 Exhibit 1: that the word "Draft" appears in the cover page and that the automatic error message "Error! Bookmark not defined" appears once in the table of contents where the page number for one subsection should appear. LUMA has corrected the November 14 Exhibit 1 to eliminate these two minor issues and is herein re-submitting it. *See Exhibit 1*.

3. LUMA respectfully requests this honorable Energy Bureau to substitute the November 14 Exhibit 1 with the attached *Exhibit 1* and consider the attached *Exhibit 1* to be LUMA's 2024 Resource Adequacy Study.

WHEREFORE, LUMA respectfully requests the Energy Bureau to take notice of the foregoing, accept the attached *Exhibit 1*, substitute the November 14 Exhibit 1 with the attached *Exhibit 1*, and consider the attached *Exhibit 1* to be LUMA's 2024 Resource Adequacy Study.

RESPECTFULLY SUBMITTED.

In San Juan, Puerto Rico, this 11th day of December 2023.

I hereby certify that I filed this Motion using the electronic filing system of this Energy Bureau and that I will send an electronic copy of this motion to lionel.santa@prepa.pr.gov.

DLA PIPER

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Exhibit 1

Corrected November 14 Exhibit 1

2024 Resource Adequacy Study

Puerto Rico Electrical System Resource Adequacy Analysis

Report

December 11, 2023

Contents

Appendices

Figures and Tables

Acronyms and Abbreviations

Acronym/Abbreviation	Definition/Clarification
BESS	battery energy storage system
BTM	behind the meter
ERM	energy reserve margin
FY2023	fiscal year 2023
FY2024	fiscal year 2024
HECO	Hawaiian Electric Company
IRP	Integrated Resource Plan
LOLE	loss of load expectation
LOLH	loss of load hours
LOLP	loss of load probability
LUMA	LUMA Energy [also, the “System Operator”]
MW	megawatt
MWh	megawatt hour
NERC	North American Electric Reliability Corporation
PRAS	Probabilistic Resource Adequacy Simulation
PREB	Puerto Rico Energy Bureau
PREPA	Puerto Rico Electric Power Authority
PRM	planning reserve margin
PV	photovoltaic
System Operator	LUMA Energy [also, “LUMA”]
VIWAPA	Virgin Islands Water and Power Authority
Acronyms & Abbreviations Appearing in Appendices Only	
ELCC	effective load carrying capability
EUE	expected unserved energy
FRCC	Florida Reliability Coordinating Council

Executive Summary

LUMA operates government-owned transmission and distribution assets in accordince with a long-term operating agreement administered as part of a public-private partnership overseen by the Puerto Rico Public-Private Partnerships Authority (P3A or P3 Authority) and is subject to regulatory oversight by the Puerto Rico Energy Bureau (PREB or Energy Bureau). Under the Puerto Rico Transmission and Distribution Operation and Maintenance Agreement between the Puerto Rico Electric Power Authority (PREPA), the Public Private Partnerships Authority (P3 Authority), LUMA Energy, LLC and LUMA Energy ServCo (collectively, LUMA) effective June 21, 2020 (T&D OMA), LUMA carries out multiple activities in order to improve the energy reliability and grid resilience of the Puerto Rico electric system. Among these are planning and conducting studies to assess the risks of resource adequacy for the electric system to meet the energy demands of Puerto Rico. While LUMA does not generate electricity, it is the system operator for Puerto Rico and carefully monitors and dispatches available generation resources – operated by Genera PR, EcoElectrica, AES and others – to meet customer demand and ensure the reliability of the overall system.

It is important to note that the generation adequacy analysis contained in this report utilizes the operational history of Puerto Rico's generators dating back to 2013 and predates the July 1, 2023 commencement of Genera PR as a generation operator in Puerto Rico.

This second resource adequacy report provides information on the strategic resource planning decisions for the Puerto Rico electric system. Even though LUMA does not own or operate any generation facilities, it is committed to doing everything it can to address Puerto Rico's long-standing generation capacity issues. For example, LUMA has been actively working with all generation operators, the Government of Puerto Rico and federal agencies to increase the amount of available and reliable generation, especially after Hurricane Fiona substantially worsened the reliability of the generation resources. LUMA's efforts to support increased generation capacity on behalf of its customers include but are not limited to:

- **Completing the First Resource Adequacy Report for Puerto Rico:** This 2022 study (for the 2023 FY) highlighted the very high risk of inadequate generation supply to meet demand and proposed solutions.

- **Advocating for Emergency Generation:** Working with key stakeholders, LUMA advocated for an emergency generation solution to reduce the impacts to customers in the short-term while continuing to work toward a more robust system in the long term.

- **Supporting the Addition of FEMA Generation:** In less than a year, this effort led to the first FEMA-funded, land-based electricity generator coming to Puerto Rico in May 2023, bringing approximately 150 megawatts of generation to support the system with an additional 200 megawatts of generation installed in September 2023.

- **Expanding Clean Energy:** LUMA is connecting approximately 3,500 customers to solar a month, a rate that has never been seen before in Puerto Rico. As of September 30, 2023, LUMA has helped connect over 71,000 customers with solar panels, representing more than 450 megawatts of clean energy added to the electric grid.

- **Collaborating on Renewable Energy Projects:** LUMA is actively working with renewable energy operators, investors and the Government of Puerto Rico to implement renewable energy projects to build a world-class energy system that will reliably serve Puerto Rico for generations to come.

Resource Adequacy Report: Key Findings

The adequacy report analysis assesses overall electricity generation sufficiency needs by evaluating the risk of insufficient electric supply to meet demand. Although there is a substantial amount of generation installed in Puerto Rico, **most of that generation is historically unreliable and too frequently incapable of operating reliably when electricity peak demand is needed**. As a result, using electric utility industry standards for measuring resource adequacy, the analysis summarized in this report concludes that **Puerto Rico has inadequate generation supply resources to deliver reasonable system stability and reliability.**

Generation adequacy is a critical component of any electrical system and this analysis speaks directly to expected reliability and stability of Puerto Rico's electric system, and the capacity of generators to meet expected demand. Key findings of this resource adequacy analysis include:

- The Loss of Load Expectation (LOLE) for Puerto Rico for FY2024, was calculated to be 37.5 days per year. On average, it is estimated that there will be 37.5 days per year where demand will not be fully served in FY2024. This measure is 375 times higher than the utility industry standard of one day in 10 years LOLE standard (0.10 days per year) observed in most of North America.

- The availability of generation is historically unreliable and too frequently incapable of operating when electricity generation is needed.

- The frequency of generation-caused load shed is likely to persist in FY2024, primarily due to the relatively poor condition and associated high forced outage rates of the existing generators in the electrical system. Both in the forecast and in the recent historical data, the average number of days resulting in generation-caused load shed is above 3 days per month.

- The 350 MW of generation added by FEMA after Hurricane Fiona has reduced the risk of insufficient generation. It is not certain at this time how long the 350 MW emergency generation units will remain. Lacking those resources, the risk to customers would be substantially higher.To help further reduce the risk of load shed, it is critical that overall generation plant availability be improved to ensure sufficient resource adequacy exists to meet forecasted energy demand. The addition of dependable bulk supply resources would reduce the risks of shortfalls.

- To help address future resource issues, LUMA proposes the addition of generation resources on a permanent basis as well as emphasizing several demand side mitigation efforts including a demand response program. While the recently approved Battery Emergency Demand Response Program is not specifically included in this analysis, a program is modeled as a senstivitiy and would certainly reduce load shed impacts to customers. Increased consumer outreach related to energy efficiency and voluntary conservation efforts are additional measures that LUMA is pursuing to improve customer outcomes.

Roles & Responsibilities

The legal framework for the electric system established by Act 17-2019 and Act 57-2014 provides for the desegregation of the Puerto Rico electric system functions, including the division of generation from transmission and distribution activities Accordingly, and in accordance to Act 120-2018, as amended by Act 17-2019, today, these PREPA functions have been delegated and Genera PR is responsible for operation and maintenance of the PREPA generation facilities and other private generation facilities are operated and maintained by independent power producers, while LUMA is responsible for the transmission and distribution activities, including overall coordination, planning and analyses. As previously stated, LUMA does not own or operate any generation facilities.

Integrated Resource Plan

The Energy Bureau approved a Modified Action Plan in August 2020 based on the Integrated Resource Plan (IRP) developed by PREPA in Case No. CEPR-AP-2018-0001, *In Re: Review of Puerto Rico Electric Power Authority Integrated Resource Plan*.

This resource adequacy report provides important inputs into the 2024 IRP currently being prepared by LUMA and to be submitted to and reviewed by the Energy Bureau in Case No. NEPR-AP-2023-0004, *In Re: Review of the Puerto Rico Electric Power Authority Integrated Resource Plan*. The report is also intended to support to processes and discussions overseen by the Energy Bureau which will help drive how Puerto Rico can reduce the risk of insufficient supply to meet energy demand.

LUMA is committed to working with government, generators, and the Energy Bureau to address these systemic generation issues to provide the people of Puerto Rico with safe, reliable, and clean energy. While this report supports decision-making regarding generation retirements, additions, modifications, maintenance schedules, and other items to reduce the risk of insufficient electric supply, specific recommendations on generation capacity additions (including determining which technologies are best suited to most effectively meet system needs) are the subject of the integrated resource planning process.

Report Scope and Methodology

At a high level, resource adequacy analyses quantify the risk that an electrical system is unable to serve system load because of insufficient generation capacity. Electrical system resource adequacy guidelines are based on regulatory requirements, system operator policies, and utility practice including policies set by the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Corporation (NERC), state/territory governments, and regional regulating authorities. Standards for resource adequacy across the industry are based on the needs of the specific utility.

The methodology followed for assessing the Puerto Rican electric system resource adequacy as discussed in this report is consistent with guidance provided by both United States regulators and electrical planning regions.

The focus time horizon for this analysis was fiscal year 2024 (FY2024), which spans from July 1, 2023, to June 30, 2024.

Puerto Rico's Planning Reserve Margin

Puerto Rico's electric system currently has an installed front-of-the-meter nameplate capacity of approximately 5,400 MW;[1] however, due to extended outages of certain power plants and derates,[2] only about 4,600 MW are currently operational. For reference, peak load in the system is approximately 3,000 MW. Approximately 92% of the operating generating capacity comes from dispatchable fossil fuel-fired generators (also known as "thermal generators"), including power plants that consume natural gas, residual oil, coal, and diesel fuel. The remaining generating capacity comes from renewable resources, predominantly solar. In addition, Puerto Rico has approximately 580 MW of installed behind-the-meter generation which is primarily solar (e.g., solar panels on the roofs of homes).

A comparison of the forecasted electric demand in Puerto Rico to the total nameplate generation capacity of the Puerto Rico electric system indicates that the Planning Reserve Margin (PRM) for Puerto Rico is approximately 67% (5,000 MW/3,000 MW -1). In general, the PRM is in line with other similarly sized islands (many that achieve high performance with respect to resource adequacy); however, a simple comparison of the PRM in Puerto Rico to the PRM values in other similar locations masks the significant challenges Puerto Rico faces daily with respect to generation resource adequacy. For example, in Hawaii the Hawaiian Electric Company has reported that on Oahu the margin of available capacity to peak load was approximately 60%[3]; however, in Hawaii, the generator forced outage rates are significantly lower than in Puerto Rico. As a result, generators in Hawaii can operate much more reliably with fewer generator outages than those in Puerto Rico. As noted earlier, although there is a substantial amount of generation installed in Puerto Rico, much of the generation is unreliable and too frequently incapable of operating when electricity generation is needed.

Resource Adequacy Calculation Results and Implications

The LOLE for Puerto Rico in FY2024, is calculated to be 37.5 days per year, meaning that, on average, it is estimated that there will be 37.5 days per year where load will not be fully served in FY2024. This measure is 375 times higher than the utility industry benchmark of one day in 10 years LOLE standard (0.10 days per year). The following table summarizes the base case LOLE and loss of load hours (LOLH) results of the analysis. The LOLH reflect the expected average number of hours in FY2024 when there will be insufficient generation capacity available to serve demand.

Table ES-1: Calculated Resource Adequacy Risk Measures, Current System (FY2024)

Measure	Loss of Load Expectation (LOLE)	Loss of Load Hours (LOLH)
Average	37.5 Days / Year	194.5 Hours / Year
Industry Benchmark Target	0.1 Days / Year	—

Simulations for the 12-month time period from July 1, 2023, to June 30, 2024, are based on an hourly basis to calculate if there is sufficient available generation capacity to meet load for each hour of each

[1] This value includes utility scale renewables, but excludes any behind-the-meter generating capacity (for example, solar panels on the roofs of residential homes.)
[2] A derated unit is a unit that is not able to operate at its design output level but can operate at a lower output level.
[3] Hawaiian Electric Company Inc., Adequacy of Supply, 29 January 2021. Over two-thirds of the population of the U.S. state of Hawaii live on O'ahu.

day. FY2024 was simulated many times, with each iteration considering forced outages occurring randomly at different times, i.e., a Monte Carlo simulation. The forced outage rates considered for this analysis are based on historical forced outage data. The output of the analysis is a statistical distribution of simulation results that provide an estimate of the risk associated with the potential of generation shortfalls.

The simulations considered electrical contributions from both thermal generators and renewable generators. Inputs into the simulations, such as generator available capacity, forced outage rates, renewable generation, and similar items, are based on historical operating data for the generators.

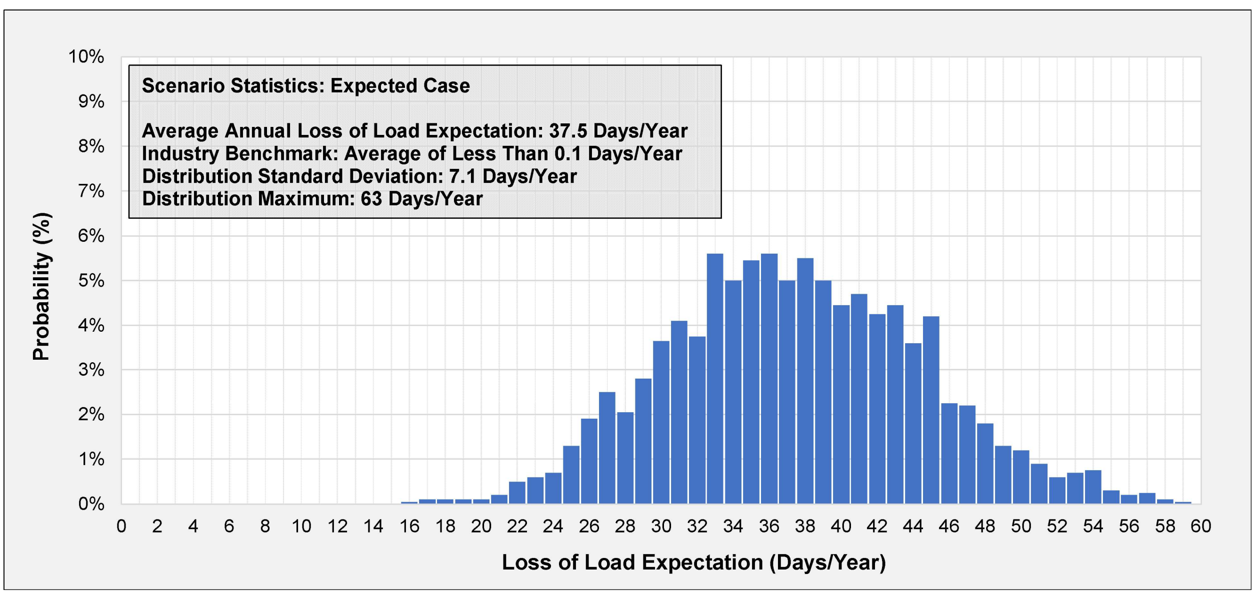
In addition, this analysis sets system load equal to the historical load experienced during calendar year 2022 (with adjustments to correct for the island-wide outages in the immediate aftermath of Hurricane Fiona).

This study presents the impact of the 350 MW of FEMA emergency generation as a sensitivity to the Base Case. As is detailed in the sensitivity results, 350 MW of highly available generation reduces the risk substantially. There is currently uncertainty over the duration of this generation and therefore it was not included as part of the Base Case assumptions.

Base Case Results

The results of the resource adequacy analysis confirmed that Puerto Rico does not meet the industry standard resource adequacy risk targets. As shown in the figure below, the average LOLE for Puerto Rico was calculated to be 37.5 days per year, while the average LOLH was calculated to be 194.5 hours per year. This LOLE is 375 times higher than the commonly accepted one day in 10 years LOLE standard (0.10 days per year). The output of the analysis is a statistical distribution of how many days there is not enough generation capacity to meet load. The characteristics of the distribution (i.e., distribution width, average) help to define the risk of the system not having sufficient available capacity to meet load for every hour. The following figure presents the results of the analysis.

Figure ES-1: Loss of Load Expectation Probability Chart, FY2024

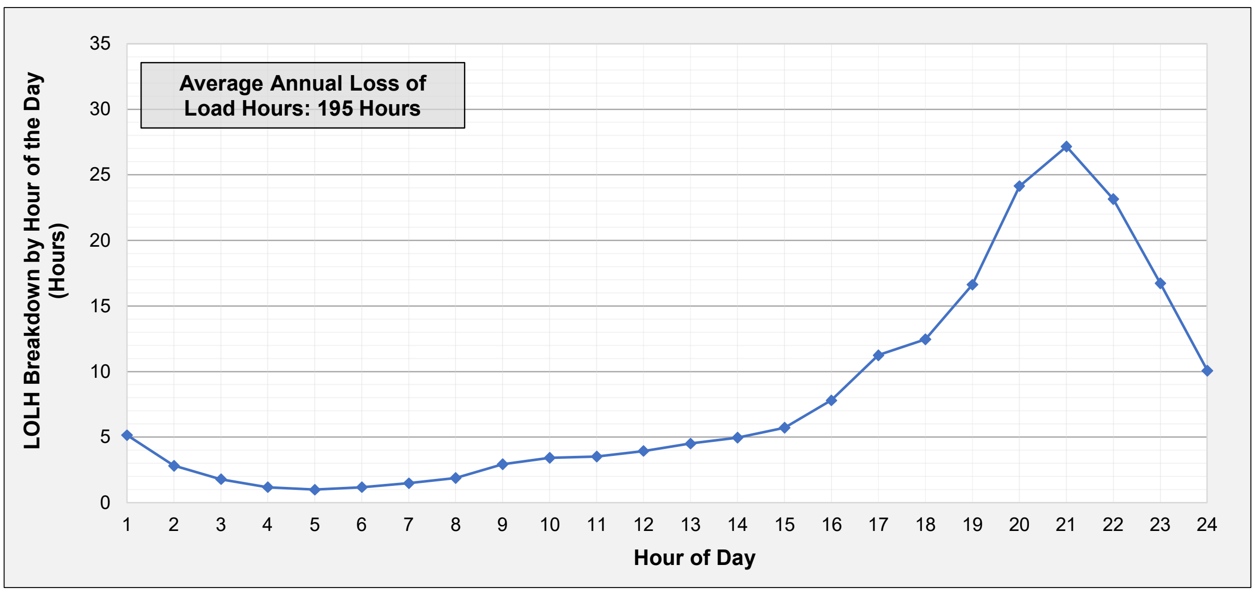


The figure (ES-1) illustrates the calculated probability of how many days load will exceed generation capacity in FY2024. Based on the distribution, there is a 50% probability that the number of days of loss of load will be greater than or less than 37.5 days, with 37.5 days defining the center of the distribution. Note that the results do not forecast what will actually occur with respect to resource adequacy in FY2024; however, the figure does help to quantify the risk, or probability, of how many loss of load days are to be expected in FY2024. **It is important to note that an hour where there is a shortfall in generation capacity does not mean that all customers in Puerto Rico will be without electricity for that hour. Instead, a forecasted deficit signifies that there is not enough generation to serve all load and thus some customers will experience temporary electricity outages**.

Compared to utility industry standards, the results for Puerto Rico have a "wide" distribution. In other words, there is a high probability of much greater than zero days per year LOLE.

Results of the resource adequacy analyses can also be visualized on an hourly level. The following figure presents the average number of LOLH, broken out by hour of the day. The majority of LOLH are observed during the evening hours, when system load is highest and when solar production is diminished or unavailable to the electric system. Approximately 62% of the observed LOLH in the resource adequacy simulation were observed to occur from 6 p.m. and 11 p.m.

Figure ES-2: Calculated Loss of Load Hours Broken Out by Hour of the Day



From the perspective of improving system resource adequacy (i.e., reducing LOLE), the results indicate that the most effective solutions will be those targeted at being able to help meet load during the evening peak – solutions such as energy storage systems, additional thermal generation, or other dispatchable resources.

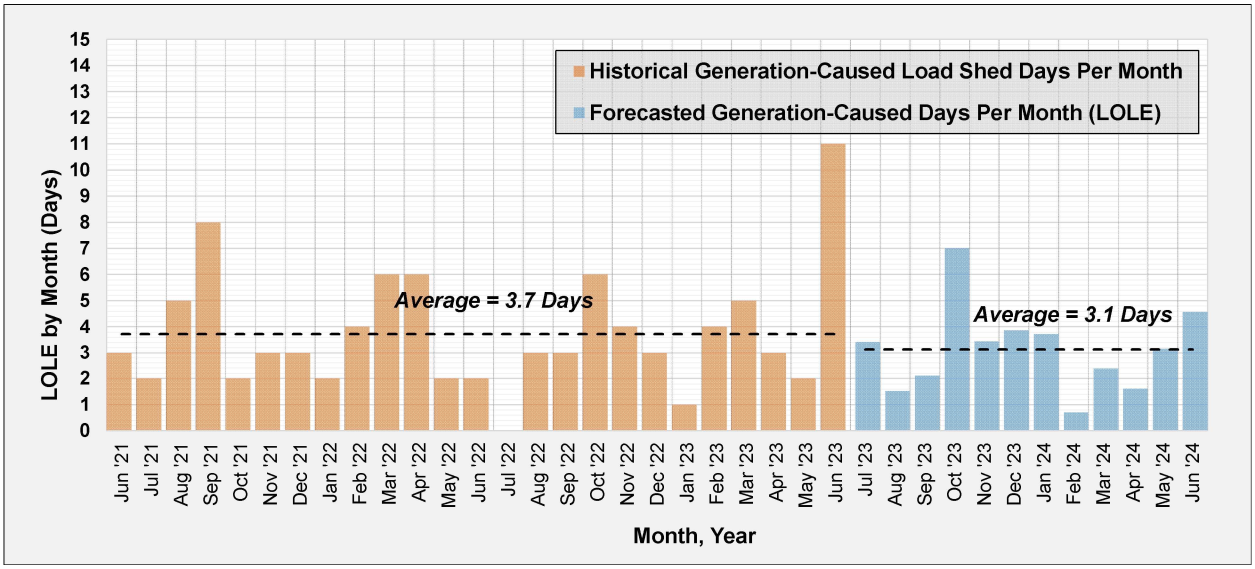
Various characteristics of the Puerto Rico electric system help explain the wide distribution in LOLE, including:

- The **forced outage rates** for PREPA's existing power plants are generally very high, meaning the power plants break down frequently. When different power plants break down at the same time, there is significant risk that there will not be enough remaining generation available to cover the load. In PREPA's historical record, both the frequency and duration of forced outages are considerably higher than industry average for comparable plants. PREPA's baseload plants (the larger, less expensive units) have a historic forced outage rate of approximately 18%[4], while AES has 5% and EcoElectrica 2%.

- PREPA's power plants often require **prolonged planned maintenance outages** due to their poor current condition and relatively long durations for execution of repair activities. Whenever a power plant is on a planned maintenance outage, it is unable to generate electricity.
- Puerto Rico is both **unable to import electricity from neighbors and has a limited number of power plants** that generate electricity. The loss of a single large power plant (either for planned maintenance or a forced outage)—EcoElectrica, the Aguirre Steam units, Costa Sur Power Plant, or AES Coal—immediately reduces the total available generating capacity by roughly 10%. If one of these generators is out of service, electricity must be supplied by other plants, many of which are often either already being fully utilized or are unreliable and break down frequently.
- **Partial plant deratings** represent limitations that the generator imposes on the capacity that a plant can provide when called upon. Plant derates occur most days in Puerto Rico and last from a few days to longer term (weeks, months, or effectively permanent).

The figure below compares the historic number of generation-caused load shed days per month to the monthly forecast for FY2024. As can be observed in the figure, an improvement in the frequency of generation-caused load shed in FY2024 is not expected as compared to recent historical performance. The reason for this is primarily due to the relatively poor condition and associated high forced outage rates of the existing generators in the electrical system. Both in the forecast for FY2024 and in the recent historical data, the average number of days of generation-caused load shed is above three days per month.

Figure ES-3: Comparison of Monthly Historical and Forecasted Generation-Caused Load Shed



[4] Weighted average by unit capacity

Note: The above plot compares load shed that occurs over the course of “normal” system operation. Load shed for September 2022 after September 18th are not included in the above plot. This is because load shed for this month was primarily driven by the damage caused by Hurricane Fiona, which was an event that was beyond what is considered to be the “normal” operation of the system. The large number of days of load shed in June 2023 were driven primarily by a combination of very high temperatures (and thus high electrical demand) and generator outages.

Risk Mitigation and Conclusion

Looking ahead, the people of Puerto Rico remain critically dependent on the performance of PREPA’s generation plants to meet expected customer demand. To help reduce the risk of load shed, it is critical that generation plant availability be improved to ensure there exists sufficient resource adequacy to meet forecasted energy demand. On July 1, 2023, Genera PR assumed responsibility for PREPA’s generation plants. The resource adequacy report covers the period of time ending in June 2024. It does not factor any modifications, improvements, or operational changes that could improve the reliability of PREPA power plants that are now under Genera’s control.

As illustrated by the senstitivity results in Appendix 17, retirement of the 350 MW of FEMA emergency generation from the system would result in a substantial increase in risk to customers.Based on the current forecast, the addition of incremental dependable bulk supply resources would help reduce the risks of shortfalls. The scale and timing of further mitigation would depend largely on the size and timing of installation of additional generation resources.

In recognition of the system constrained reserve margins, LUMA is also emphasizing several demand side mitigation efforts including a demand response program, increased consumer outreach related to energy efficiency, and voluntary conservation efforts to help reduce demand on the grid, especially during peak hours between 6 p.m. and 11 p.m. LUMA will also continue to work with the Energy Bureau and key stakeholders that may offer other distributed energy resources that can provide additional system support on the margins. This current base case analysis does not include mitigation from demand response programs like the Battery Emergency Demand Response Program recently authorized by the Energy Bureau in Case No. NEPR-Mi-2022-0001, *In Re: Energy Efficiency and Demand Response Transition Period Plan*.This battery program is expected to reduce the risk of load shed to customers.

Given the importance of this issue for the people of Puerto Rico, LUMA will continue to work with all generators to minimize the impact of generation-related load shed events by coordinating plant outages, including moving them to an either earlier or later date, in order to make up for the potential generation shortfalls due to forced outages.

LUMA is also optimistic that improvements planned by Genera to the PREPA-owned thermal generation facilities will improve overall reliability in the future. LUMA continues to work closely with Puerto Rico policymakers to provide data analysis and technical supporting improved generation supply to customers. Above all, LUMA remains committed to working with the Government of Puerto Rico, the regulator, generators, and customers to take the necessary actions to help improve overall grid resiliency and build the stronger, more reliable, customer-focused and cleaner electric system the people of Puerto Rico expect and deserve.

1.0 Introduction

This is the second resource adequacy analysis provided by LUMA as operator of the transmission and distribution system and system operator (the "System Operator") with responsibilities for planning and transforming the utility to deliver a better, more reliable electrical system to the people of Puerto Rico. This report complies with LUMA's responsibility under the Puerto Rico Transmission and Distribution System Operation and Maintenance Agreement between the Puerto Rico Electric Power Authority (PREPA), P3A, LUMA Energy, LLC, and LUMA Energy ServCo LLC, effective June 21, 2020 ("T&D OMA"). It is also a requirement of Section 5.13 (d) (i) of the T&D OMA that LUMA "prepare risk assessments and analyses in support of Resource Adequacy and Generation Project or Generation Supply Contract procurement prioritization and planning, which shall take into account the Integrated Resource Plan [IRP] and Applicable Law (and which assessments and analyses the Puerto Rico Energy Bureau [PREB] may request from time to time)."

The Puerto Rico electrical system is undergoing a significant transformation toward renewable energy and energy storage. Per the submission of the PREPA IRP in 2019 and PREB'S subsequent *Final Resolution and Order on the Puerto Rico Electric Power Authority's Integrated Resource Plan*, in Case No. CEPR-AP-2018-0001, *In Re: Revew of the Puerto Rico Electric Power Authority Integrated Resource Plan*, PREPA will integrate six tranches of solar photovoltaic (PV) or equivalent renewable energy, totaling 3,750 MW (megawatt[s]) and an additional 1,500 MW of energy storage. Work on the tranches is currently ongoing. With the integration of the solar PV and energy storage resources, the current expectation is that the system will be able to retire a significant quantity of its existing thermal generation.

The overall renewable energy transformation process will take many years to complete and is currently behind the originally forecasted schedule. To date, the first tranche of new renewable generation and energy storage is not in operation and thermal generator retirements have yet to occur. In the meantime, Puerto Rico's resource adequacy performance currently is extremely poor as power outages due to lack of available generation are a frequent occurrence on the island. While the renewable transformation process will help to improve future system resource adequacy, there are additional steps that can be taken to improve the system further and potentially realize near term benefits. This report is an important step in that process as it aims to identify the system challenges and vulnerabilities in Puerto Rico from a resource adequacy perspective. This resource adequacy report itself does not specify the optimal generation technologies to fill any identified shortfall (that is typically performed as part of the IRP process); however, the resource adequacy report is a critical input to the IRP analysis.

The purpose of this report is to present an analytical framework and methodology to assess resource adequacy in Puerto Rico. Resource adequacy analysis is a basic requirement to understanding if the portfolio of generation resources can adequately meet customer needs and is performed in every North American Electric Reliability Corporation (NERC) region and most of the world's utilities. As mentioned above, it is also a requirement of LUMA's T&D OMA.

This resource adequacy report documents the generation resource adequacy modeling process, results, and implications for the Puerto Rico electrical system. The focus of generation resource adequacy modeling is to determine if enough installed and operating generation capacity is available to serve system load during all hours of the day, throughout the study period, and to provide regulators with the quantitative tools and measures to ensure customers will receive safe reliable power supplies. The resource adequacy analysis determines if there is a deficit in generation resources, and from there, the regulator and policymakers must then approve a plan to address generation shortfall.

There are a consistent set of fundamental guidelines for performing resource adequacy analyses across the energy industry; however, there can be some variation in the analysis methodology based on the specific utility or planning region. In general, the key fundamentals of resource adequacy analyses can be summarized in the following points below:

- The goal of a resource adequacy analysis is to quantify how well the existing power plants in an electrical system are reliably able to serve electrical load.
- The analysis follows a probabilistic approach to assess the probability, or risk, that load might not be met by system generators.
- Results from the probabilistic analyses are compared to a resource adequacy target, which is defined as the acceptable level of risk that the generation portfolio might not be able to serve load. The target is typically set by the location’s planning authority consistent with guidance provided by the regulator.
- The results and implications of a resource adequacy analysis are important tools that planners can use to help make decisions around generation retirements, additions, or other items related to how a utility can better serve electrical load.

The introduction section of this report provides an outline of the computational methodology for performing resource adequacy analyses in general, the methodology followed by other utilities in regions that share similarities with Puerto Rico, and the methodology used to assess generation adequacy in Puerto Rico. Note that generation resource adequacy is focused specifically on assessing generation deficiency across the system, not the constraints associated with electrical transmission and distribution systems; however, any transmission and distribution constraints will further hinder system reliability in addition to any deficiencies in generation resource adequacy.

1.1 Generation Resource Adequacy Analyses: An Overview

At a high level, resource adequacy analyses quantify the risk that an electrical system is unable to serve system load because of deficient generation capacity. Resource adequacy guidelines for utilities are influenced by numerous agencies, including the Federal Energy Regulatory Commission (FERC), NERC, state/territory governments, and other regional regulating authorities. The unique needs of each utility have created complex and varying resource adequacy requirements across the industry. Ultimately, it is the responsibility of the regulator to approve the resource planning targets proposed by the utility and the plan to achieve those targets, often through an IRP process. In Puerto Rico, the regulatory authority is PREB.

The calculations to evaluate a system’s resource adequacy are rooted in a probabilistic approach to quantify the risk that system generators will be unable to fully serve system load. The analysis considers several important variables, such as power plant generation capacity, generation derates and outages, generation intermittency, and system electrical load, among other items.

Resource adequacy requirements and calculations are often incorporated into IRPs. Resource adequacy analyses inform resource planners whether there is enough installed generation capacity, and this is often represented through a generation planning reserve margin (PRM). The PRM is defined as the amount by which the total system generation capacity exceeds peak electrical demand. For a given system, higher

PRMs typically equate to a lower risk that load will not be served during a given timeframe; however, higher PRMs also correspond to higher costs. Note that a PRM is set based on a target system reliability and may differ from utility to utility based on the unique characteristics of each location. Resource adequacy analyses can also help inform additional planning criterions that may exist for a utility, such as a requirement to have enough generation to cover the loss of the largest generator in the system or requirements to meet different reserve margins for summer versus winter seasons.

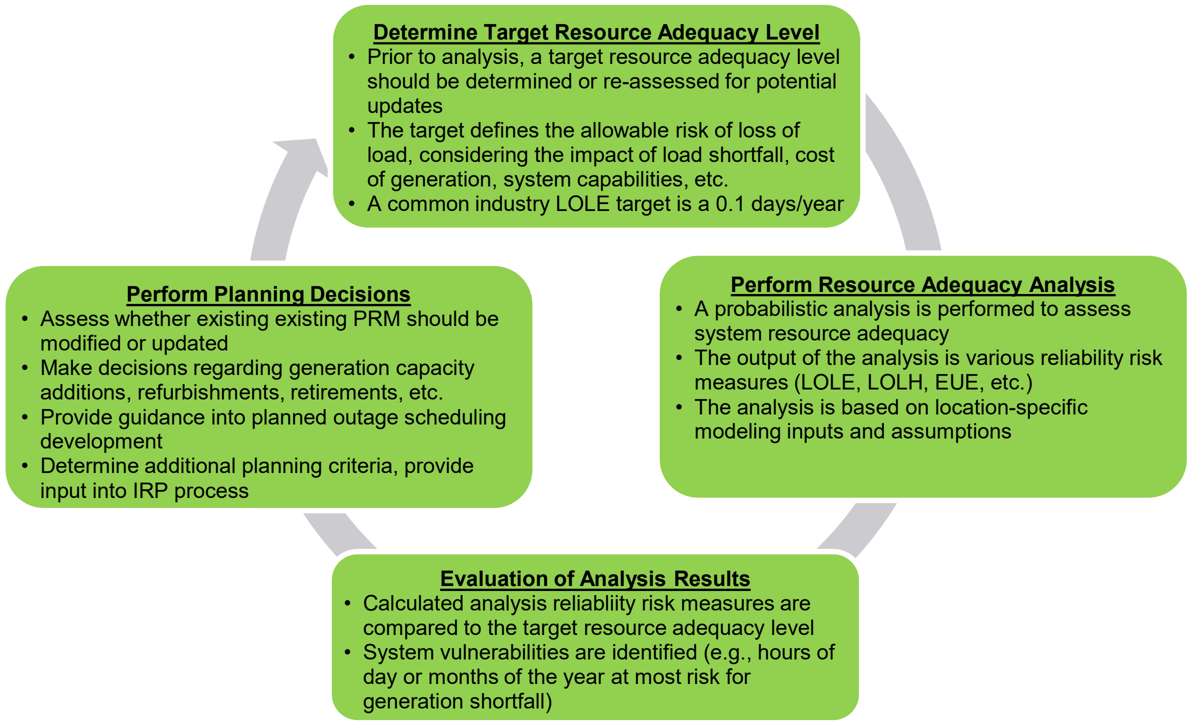
Resource planners often must balance a set of goals, such as minimizing the risk of not serving electrical load, costs, environmental impacts, etc., to develop a resource plan that represents the needs and priorities of their jurisdiction in a cost effective but resilient manner. From there, the analysis can help guide planners on various decisions, including whether to add generation capacity, incentivize demand response and behind-the-meter (BTM) programs, retire generators, and/or improve outage rates of specific units through rehabilitation (asset renewal) projects.

1.1.1 Generation Resource Adequacy Process

The process of performing a resource adequacy analysis is summarized in the following figure. The analysis is used to quantify the risk that the available generation capacity[5] will be unable to serve electrical demand. The risk is summarized using resource adequacy risk measures, which are discussed in the next section. From there, the risk is compared against the adequacy target for the utility or planning region. Based on how well the analyzed system performs related to the target, decisions and planning associated with generation additions, retirements, PRMs, and other items can be made.

[5] Available or dependable generation capacity measured in MW is calculated based on generator production profile and technology specific effective load carrying capabilities.

Figure 1-1: Resource Adequacy Process Flowchart



Multiple tools are used to conduct resource adequacy modeling in the industry, including spreadsheet-based tools, production cost modeling software, and commercial simulation software tools.

The results of resource adequacy analyses are often dependent upon numerous assumptions, and therefore vary by utility or planning region. Resource planners may evaluate a range of load forecast scenarios to assess resource sufficiency to meet these different growth scenarios. Similarly, a range of weather scenarios may be assessed, which is becoming increasingly important given the growth of variable renewable generation resources in power systems as utilities transition to carbon-free generation. Note that this resource adequacy analysis considers the 2022 actual metered system load for all resource adequacy simulations, unless otherwise specified. Finally, the frequency and duration of planned maintenance or forced outages significantly impact the risk that load might not be served by the system's generators.

1.1.2 Generation Resource Adequacy Risk Measures

When considering the output of a resource adequacy analysis, it is important to understand the key measures that define system performance. There are several different measures to consider, and the specific definitions and applications of reliability risk measures are not uniform throughout the industry. Each region of the country has different generation portfolios and load characteristics and different risk factors, which will result in different targets. For example, the Pacific Northwest has large amounts of hydropower, California is extremely vulnerable to wildfires and import/export limitations, and New England has limited access to natural gas supplies. The key reliability measures for the purposes of this analysis are in the table below. Each measure represents different aspects of a system's reliability including the frequency, duration, and magnitude of generation shortfall events.

Table 1-1: Resource Adequacy Risk Measures

Resource Adequacy Risk Measure	Definition
Loss of Load Hour (LOLH)	The expected number of hours within a given time horizon (usually one year) when a system's hourly demand is projected to exceed the available generating capacity.
Loss of Load Expectation (LOLE)	The expected number of days in the time horizon (usually one year) for which available generation capacity is insufficient to serve the demand. LOLE measures the number of days in which involuntary load shedding can be expected to occur, regardless of the number of consecutive or non-consecutive LOLHs in the day. For example, if there are two days in a year where there is insufficient generation to serve load (regardless of the duration of the outage or how many events occur in a single day), then LOLE would equal two days per year.
Loss of Load Probability (LOLP)	The probability of demand exceeding the available generation capacity during a given period.
Expected Unserved Energy	The summation of the expected number of megawatt (MW) hours of load that will not be served in a specific time interval because of demand exceeding the available generation capacity. This energy-centric measure considers the frequency, magnitude, and duration for all hours of the period.

Note that an hour where there is a shortfall in generation capacity does not mean the entire island of Puerto Rico will be without electricity for that hour. Instead, it signifies that there is not enough generation to serve all load on the island and thus some customers will experience electricity outages.

1.1.3 Computing System Resource Adequacy

A resource adequacy analysis is probabilistic in nature. As such, its output is typically processed in accordance with regulatory oversight to derive the probability, or risk, that an electrical system would be unable to serve system load over a specified period. An industry-approved probabilistic iterative method was used to assess the resource adequacy of Puerto Rico's electric grid. Using this method, all hours of fiscal year 2024 (FY2024) were simulated, calculating whether there will be sufficient available generation capacity to meet load for each hour of every day. Since some of the variables that impact a power plant's ability to generate electricity are random (for example, the timing of forced outages), the year is re-simulated thousands of times. By evaluating the aggregated output of all simulations, one can quantify the risk of not meeting system load due to resource capacity deficiency. All scenarios analyzed considered 2,000 iterations as this was a threshold at which results were considered statistically converged. Convergence was determined by considering average loss of load hours (LOLH) of all completed iterations and how that value changed with subsequent iterations. Once the change in average LOLH with each subsequent iteration fell below an acceptable threshold, the simulations were considered converged. Additional information on simulation convergence is provided in Appendix 7.

1.2 Resource Adequacy Regulatory Guidance

Support for probability-based resource adequacy assessments has increased due to changing electrical load profiles, the growth of intermittent (renewable) resources, shifting peak hour demand, and other factors that impact resource adequacy. Recent NERC surveys[6] indicate that most electrical regions in North America are using probabilistic approaches to examine resource adequacy questions, and if they

[6] North American Electric Reliability Corporation, Probabilistic Adequacy and Measures, July 2018.

are not, they are considering incorporating probabilistic approaches. Resource adequacy analyses inform planning reserve margin decisions, generator additions and retirements, integrated resource planning, market-based resource procurement, and other system planning activities.

In 2017, FERC approved NERC Reliability Standard BAL-502-RF-03[7], which created requirements for entities registered as planning coordinators to perform and document resource adequacy analyses. The standard describes that a PRM should be based on an adequacy criterion such that the average expectation of loss of load across a large number of simulations for the same planning year, but under different generator outage conditions, is equal to 0.10 days per year. This target is also known as the "one day in 10-year" criterion since it means that on average only 1 day in every ten years will experience a shortfall resulting in load-shed. This resource adequacy standard also provides guidance to include load forecast characteristics, resource characteristics, and transmission limitations that prevent delivery of generation reserves in the resource adequacy analysis. Note that Puerto Rico is not under NERC jurisdiction; however, the NERC standards are useful guidelines for the island.

The growth of variable generation sources, such as wind and solar power plants, has resulted in electrical planners having to think carefully about how best to capture the electrical capacity contributions provided by each energy resource technology with respect to resource adequacy calculations. In March 2011, NERC released a guideline report, *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning*.[8] This report identified the need for alternative approaches rooted in probabilistic analysis when determining variable generation capacity contributions towards availability and resource adequacy. Further, the report recommended the comparison of adequacy study results based on alternative metrics than solely PRM.

Continuing this expanding resource adequacy guidance, NERC released the 2018 technical reference report, *Probabilistic Adequacy and Measures*.[9] Due to the evolving resource mix landscape as a result of increasing penetration levels of variable generation, this technical reference report focused on identifying, defining, and evaluating more probabilistic approaches and risk measures to provide insights into resource adequacy assessments. Resource evaluation planning approaches range from relatively simple calculations of PRMs to extensive generation resource adequacy simulations that calculate system loss of load probability (LOLP) values.

1.3 Resource Adequacy and Electric System Resiliency

This document focuses on resource adequacy pertaining to normal system operating conditions. Resource adequacy performance can also be analyzed for non-normal, or adverse operating conditions. Hurricanes, tropical storms, earthquakes, and other similar disasters would be defined as adverse operating conditions. An industry term typically associated with infrastructure preparedness and performance during and after adverse operating conditions is "resiliency." White House Presidential Policy Directive 21[10], which focuses on critical infrastructure security and resilience, defines system resiliency as,

[7] North American Electric Reliability Corporation, Standard BAL-502-RF-03, October 2017.
[8] North American Electric Reliability Corporation, Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning, March 2011.
[9] North American Electric Reliability Corporation, Probabilistic Adequacy and Measures, July 2018.
[10] Presidential Policy Directive -- Critical Infrastructure Security and Resilience, The White House, Office of the Press Secretary, February 12, 2013.

> The term ‘resilience’ means the ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions. Resilience includes the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents.

As such, a resilient system is one that is designed not only to be able to withstand adverse operating conditions, but also to be able to recover quickly. Robust resiliency planning is essential to help minimize the negative impacts caused by a high severity event. This is especially true on an island since it is not possible to import electricity from a neighbor in the aftermath of a disaster. While evaluating electrical system resiliency in the face of adverse operating conditions is not a focus of this report, generation resource adequacy is an important part of resiliency planning, and the tools and methodology presented in this report can be used to help quantify the effectiveness of resiliency measures.

Generator and power system resiliency are intricately tied to generation resource adequacy; however, the methodology and assumptions for analyzing resource adequacy for normal operating conditions differ from those tied to analyzing resource adequacy during high severity events. Given high severity events are also often defined by a cascade of system failures, there may be other failures within the electrical system that arise during the event. Failures and challenges such as transmission outages, fuel supply disruptions, flooding, etc., can all place significant stress on the ability of available generators and system equipment to serve load. There is a separate work stream related to system resiliency ongoing in Puerto Rico currently being supported by the U.S. Federal Emergency Management Agency (FEMA).

1.4 Generation Adequacy for Different Utilities

A comparison of resource adequacy approaches for various other utilities and planning entities that have similarities to Puerto Rico is provided in this section of the report and in Appendix 3. Utilities and planning entities considered in this review were selected based on having similar characteristics to Puerto Rico, including other islands, similar geographic location and climate, and similar renewable integration goals.

1.4.1 Resource Adequacy for Other Islands

Maintaining high levels of system resource adequacy is especially challenging for islanded systems. The main reason for this is that islands are not able to import electricity from neighboring utility systems during times of peak demand and/or deficient generation capacity. In contrast, a utility on the U.S. mainland would generally be able to import electricity from neighbors when needed. In addition, many islands, including Puerto Rico, have a relatively small number of total generators available to be dispatched at any point in time. As a result, islands are often at a high risk of not being able to serve load in the event of a loss of a large generator, due to the simple fact that there is a limited number of other generators that could be dispatched to cover for the large generator’s outage. In contrast, planning regions and large utilities in the U.S. mainland can have hundreds, and sometimes thousands, of other generators that could be dispatched to cover for power plant outages.

Table 1-2: Resource Adequacy Comparison by Location

Utility / Planning Entity	Target Risk Measure (LOLE, LOLP, LOLH, or Similar Values)
Virgin Islands Water and Power Authority	1 day per year in 2020, reducing 1 day per 10 years in 2044[1]

Utility / Planning Entity	Target Risk Measure (LOLE, LOLP, LOLH, or Similar Values)
Hawaiian Electric Company	Energy Reserve Margin, based on 1 day per 4.5 years[2]
Guam Power Authority	1 day per 4.5 years[3]

Sources:

1. VIWAPA Final IRP Report, 21 July 2020.
2. Hawaiian Electric Company Inc., Adequacy of Supply, 29 January 2021.
3. Guam Power Authority 2022 Integrated Resource Plan.

1.4.2 U.S. Virgin Islands

As one of Puerto Rico's island neighbors, the U.S. Virgin Islands has several similarities to Puerto Rico from a generation resource adequacy perspective. Neither can import electricity from neighbors (as would be the case on the U.S. mainland), both have similar climates, and both have similar renewable energy goals. The utility that operates the electrical system for the U.S. Virgin Islands, the Virgin Islands Water and Power Authority (VIWAPA), released an updated IRP in 2020 where they discussed several items related to the resource adequacy considerations for the Virgin Islands.[11] The IRP planning horizon spanned 2020-2044 and notes the requirement that 50 percent of electricity generation in the U.S. Virgin Islands (as a percentage of peak demand) must come from renewable resources by 2044. VIWAPA's resource adequacy planning criteria sets a loss of load target of 1 day per year in 2024, which gradually reduces to 0.10 days per year by 2044. In addition, VIWAPA has an "N-1-1" planning criterion, which requires sufficient installed generation capacity to be available during the loss of two of the largest generators, or key transmission lines.

1.4.3 Hawaii

From generation resource adequacy perspective, Hawaii also has several similarities with Puerto Rico. Neither can import electricity from neighbors, both have similar climates, and both are undergoing the integration of more renewable resources. The Hawaiian Electric Company (HECO) operates the electrical system in Hawaii. HECO's resource adequacy considerations are summarized in a recent filing with the Hawaiian Public Utility Commission, titled the 2021 Adequacy of Supply.[12] In the filing, HECO notes some recent modifications to their resource adequacy planning criteria, namely the implementation of an "energy reserve margin" (ERM) concept for the purposes of examining resource adequacy in all hours of the year. The ERM is defined as the percentage of excess system capacity over system load in each hour and accounts for Hawaii's inability to import emergency power from a neighboring utility. The ERM is rooted in HECO's guideline of requiring the system loss of load expectation (LOLE) to be less than one day per 4.5 years.

The ERM concept being used by HECO includes contributions from variable renewable generators, energy storage, demand reduction programs, and other similar resources. HECO defines the dependable

[11] VIWAPA Final IRP Report, 21 July 2020.
[12] Hawaiian Electric Company Inc., Adequacy of Supply, 29 January 2021.

contributions from renewable generators to resource adequacy probabilistically, based on the following equation:

$$Dependable\ Capacity_{Hourly} = Average\ Generation_{Hourly} - N \cdot (Standard\ Deviation)$$

Here the hourly dependable capacity of the renewable generator is equal to that generator's historical production for that hour, reduced by the standard deviation of the historical production. The value of N is set by HECO to be 1 for wind generators and 2 for solar generators. For example, if a solar power plant on average has generated 100 MW (megawatt[s]) at noon, but with a standard deviation of 20 MW, then only 60 MW would be considered as dependable capacity (100 MW – 2 x 20 MW = 60 MW) at noon. Per the recent recommendation of the Hawaii Public Utilities Commission, HECO is also assessing renewable generator capacity contributions using stochastic draws of historical (or simulated) weather years.[13]

1.4.4 Guam

Guam's electrical system is operated by the Guam Power Authority. As an island with a similar climate to Puerto Rico, Guam shares many similar resource adequacy challenges as Puerto Rico. The 2022 IRP filing notes the island targets a one day per 4.5 years LOLE resource adequacy risk measure.[14] Guam Power Authority indicates that at least a 75% PRM is required to meet this level of resource adequacy in the future. Guam Power Authority also currently utilizes an "N-2" planning criteria, requiring sufficient generation to cover the loss of the island's two largest generating sources.

[13] Hawaii PUC Docket No. 2018-0165, Approving with Modifications Hawaiian Electric's Grid Needs Assessment, page 21
[14] Guam Power Authority 2022 Integrated Resource Plan.

2.0 Puerto Rico's Electrical System and Resource Adequacy

2.1 Puerto Rico's Power Plants

The size, number, availability, and generating characteristics of the installed power plants in an electrical system are some of the most important inputs into resource adequacy analyses. Puerto Rico's electricity comes from three different sources:

1. Thermal power plants, or power plants that consume fossil fuels
2. Renewable power plants, such as solar, wind, and hydroelectric
3. BTM generators, such as solar panels on residential homes, or other similar sources

The following subsections provide an overview of each of the above items, including considerations for how they impact overall system resource adequacy analyses.

2.1.1 Puerto Rico's Thermal Power Plants

Puerto Rico's electric system currently has an installed nameplate, front-of-the-meter generating capacity of approximately 5,400 MW[15]; however, due to extended outages of certain power plants and derates[16], only about 4,600 MW are currently operational. Approximately 92% of the operating generating capacity comes from dispatchable fossil fuel-fired generators (also known as thermal generators), including power plants that consume natural gas, oil, coal, and diesel fuel (System Operations uses an effective capacity for planning and dispatch of 4,600 MW, not including renewables). The remaining generating capacity comes from renewable resources, predominantly solar, which sums to approximately 400 MW of nameplate capacity. In addition, Puerto Rico has approximately 580 MW of installed BTM generation (for example, solar panels on the roofs of homes), which is primarily solar.

The table that follows summarizes the operating thermal generating resources and shows their historical forced outage rates for reference (compiled from data between 2013 and 2022). Forced outage rates are defined as the percentage of time the power plants are broken down and unable to generate electricity. From a resource adequacy perspective, there are several important points to note in the following table. First, the forced outage rates of many of the existing thermal power plants have historically been very high, with approximately 2,500 MW of Puerto Rico's installed generators having historic forced outage rates of 15% or more (and many of these generators having forced outage rates of 30% or more). For reference, the average equivalent forced outage rate for North American power plants over the past five years was 7.25%.[17] Since a generator that is broken down is unable to generate electricity, the higher the forced outage rates, the higher the risk that there will be a shortfall in generation capacity needed to serve system load. The duration of a forced outage is also a very important consideration for resource adequacy. Repairs after a forced outage can be made quickly, or can take many months, as was the case with the Costa Sur Power Plant following the damage it sustained during the January 2020 earthquakes.

[15] This value includes utility scale renewables, but excludes any BTM generating capacity (for example, solar panels on the roofs of residential homes.)
[16] A derated unit is a unit that is not able to operate at its design output level but can operate at a lower output level.
[17] North American Electric Reliability Corporation, 2022 State of Reliability: An Assessment of 2021 Bulk Power System Performance, July 2022, page 37.

For this analysis, the duration of a forced outage for each thermal plant was assumed to be 40 hours, which represents an average repair time.[18]

Additionally, many of the power plants were first constructed over 50 years ago, and many of these generators have not been properly maintained. This not only is the culprit of the high forced outage rates, but it also results in power plant operators needing to take more frequent and longer scheduled maintenance outages than might otherwise be expected for a power plant of similar type and vintage that had been sufficiently maintained. As opposed to forced outages, scheduled maintenance outages can be planned for; however, a scheduled outage still results in the power plant being unable to generate electricity, which increases the risk that there will not be enough total system capacity needed to serve system load.

One additional cause of plant outages (or limited power plant operation) is thermal power plant emissions. The U.S. Environmental Protection Agency regulates power plant emissions and requires Puerto Rico's generators to have emissions under federally mandated levels for certain combustion by-products (e.g., NOx, SO_2, particulates). Some of Puerto Rico's thermal power plants are unable to continuously comply with the U.S. Environmental Protection Agency regulations, and as a result are either required to shut down to make improvements that will improve emissions, or limit operation. For this analysis, units that are inoperable due to emissions restrictions are considered inactive; however, units that are operable, but operationally restricted, are considered as available dispatchable capacity in this analysis. Operationally restricted units are considered to still be able to contribute towards meeting system load because these units still can operate for short periods when there would otherwise be loss of load.

Each of the thermal power plants listed in the following table is modeled for the resource adequacy calculations documented in this report, including the available capacity, historical forced outage rate, and any scheduled maintenance outages.

Table 2-1: Summary of Expected Operating Thermal Generators in FY2024

Generator Name	Start of Operations	Fuel	Nameplate Capacity (MW)	Available Capacity (MW)	Historic Forced Outage Rate (%)
AES 1	2002	Coal	227	227	5
AES 2	2002	Coal	227	227	5
Aguirre Combined Cycle 1[1]	1977	Diesel	296	220	40
Aguirre Combined Cycle 2[1]	1977	Diesel	296	100	30
Aguirre Steam 1[2]	1971	Bunker	450	350	20
Aguirre Steam 2	1971	Bunker	450	330	15
Costa Sur 5	1972	Natural Gas	410	350	12
Costa Sur 6	1973	Natural Gas	410	350	15
EcoElectrica	1999	Natural Gas	535	535	2

[18] A sensitivity analysis around modeled generator forced outage duration was performed and is documented in Appendix 8 of LUMA's *FY2023 Puerto Rico Electrical System Resource Adequacy Analysis* report. The findings indicated that for a consistent set of generator forced outage rates, differences in the modeled generator forced outage duration resulted in reasonably small differences in calculated LOLE and no discernable differences in LOLH.

Generator Name	Start of Operations	Fuel	Nameplate Capacity (MW)	Available Capacity (MW)	Historic Forced Outage Rate (%)
Palo Seco 3	1968	Bunker	216	190	12
Palo Seco 4	1968	Bunker	216	190	18
San Juan 7	1965	Bunker	100	70	30
San Juan 9	1968	Bunker	100	90	8
San Juan Combined Cycle 5	2008	Diesel / Natural Gas	220	200	12
San Juan Combined Cycle 6	2008	Diesel / Natural Gas	220	200	12
Cambalache 2	1998	Diesel	82.5	75	10
Cambalache 3	1998	Diesel	82.5	75	10
Mayagüez 1	2009	Diesel	55	50	30
Mayagüez 2	2009	Diesel	55	25	30
Mayagüez 3	2009	Diesel	50	50	30
Mayagüez 4	2009	Diesel	50	50	30
Palo Seco Mobile Pack 1-3	2021	Diesel	27 each (81 total)	81	9
7 Gas Turbines (Peakers)[3]	1972	Diesel	21 each (147 total)	147	40
Total			**4,976**	**4,182**	**—**

Notes:

1. Both Aguirre Combined Cycle 1 and 2 are modeled as two units each (i.e., Aguirre Combined Cycle 1 is modeled as two 110 MW units, each with a forced outage rate 40%) to more accurately capture the fact that a single forced outage to the power plants typically only results in some subset of the power plants being out of service (as opposed to the entire power plant being out of service).
2. The Base Case, which reflects the current system, considers Aguirre 1 to be out of service for the duration of the simulations. This generator is kept out of service in order to account for the planned maintenance schedule overruns that are very common to the main generators on the island. This is described further in Appendix 5 and Appendix 9.
3. A total of 18 gas turbines, each with a capacity of 21 MW, are installed. Only 7 are considered to be operational due to frequent outages at these units

2.1.2 Puerto Rico's Renewable Power Plants

The table below summarizes the operating front-of-the-meter renewable power plants installed in Puerto Rico for the purposes of this FY2024 analysis. Solar and wind are the primary sources of renewable energy in Puerto Rico. Note that Puerto Rico has a small fleet of hydroelectric power plants with a design capacity of approximately 100 MW. Most of these units date back to the 1930s and 1940s, many are not operational or are in disrepair, and the few that do operate experience high forced outage rates (50% or higher). After accounting for long-term outages / damage and unit limitations, the effective capacity of these units typically only hovers around 20 MW. For this reason, the hydroelectric plants are not listed in the following table and are not considered for the resource adequacy analyses documented in this report.

Since renewable generators have periods of intermittent electricity production, it was important to determine the amount of hourly renewable generation that could reliably be considered as available to serve load from a resource adequacy perspective. The methodology used in these analyses shares similarities to the methodology employed by HECO, as described earlier. For these analyses, actual historical generation data (between 2019 and 2022) from each of the operating renewable power plants listed in the table below was analyzed. From there, each generator's 90th percentile lowest production level for each hour was identified and used as the resource's capacity contribution for the resource adequacy calculations. For the planned renewable generators (Punta Lima, Ciro 1, and Xzerta), the ninetieth percentile lowest production levels of the historical generation from the combined existing renewable generators were used to forecast the planned renewable generation. This overall methodology captured the contributions of the renewable generators to improving system resource adequacy from a statistical framework, accounting for the intermittency of the generators. It was also fundamentally based on the actual historical production levels of the existing renewable generators.

Properly capturing the hourly capacity contributions from variable generators is an important consideration for resource adequacy analyses since the hourly contributions of variable generators are, by definition, uncertain. Overestimating the capacity contribution of variable generators can leave the electrical system with capacity shortfalls in the event the variable generators are unable to generate when they are expected to, while underestimating the capacity contribution of variable generators can make the electrical system appear less reliable than in actuality. As a result, a sensitivity analysis was performed to investigate different variable generator capacity contributions beyond only the 90th percentile historical generation. This sensitivity analysis is described in Appendix 7. The sensitivity analysis results illustrate that the use of less conservative hourly capacity contributions from the variable generators (i.e., 50th percentile instead of 90th percentile of hourly historical generation) modestly improves system LOLE. In addition, an estimate of the ELCC of the solar PV resources was calculated in Appendix 30.

Table 2-2: Summary of Operating Renewable Generators

Generator Name	Commercial Operation Date	Fuel	Nameplate Capacity (MW)
AES Ilumina	2012	Sun	20
Fonroche Humacao	2016	Sun	40
Horizon Energy	2016	Sun	10
Yarotek (Oriana)	2016	Sun	45
San Fermin Solar	2015	Sun	20
Windmar (Cantera Martino)	2011	Sun	2.1
Windmar (Vista Alegre / Coto Laurel)	2016	Sun	10
Pattern (Santa Isabel)	2012	Wind	75
Fajardo Landfill Tech	2016	Methane Gas	2.4
Tao Baja Landfill Tech	2016	Methane Gas	2.4
Punta Lima	2023	Wind	26
Ciro 1	2023	Sun	90
Xzerta	2024	Sun	60
Total			**402.9**

2.1.3 Puerto Rico's Behind the Meter Generation Resources

The table below shows the estimated amount of generation that is installed BTM across the different regions of Puerto Rico (as of Q1 2022). BTM generation is broken down between resources connected to the distribution system and resources connected to the transmission system; both of which are primarily composed of rooftop solar.

These BTM resources are considered in the analysis as reductions in system load.[19]

Table 2-3: Summary of BTM Generation by Area

Area	BTM Generation
Caguas	108
Bayamón	119
Ponce	82
Carolina	75
Mayagüez	63
San Juan	79
Arecibo	54
Total	**580**

2.2 Puerto Rico Electrical Load / Demand

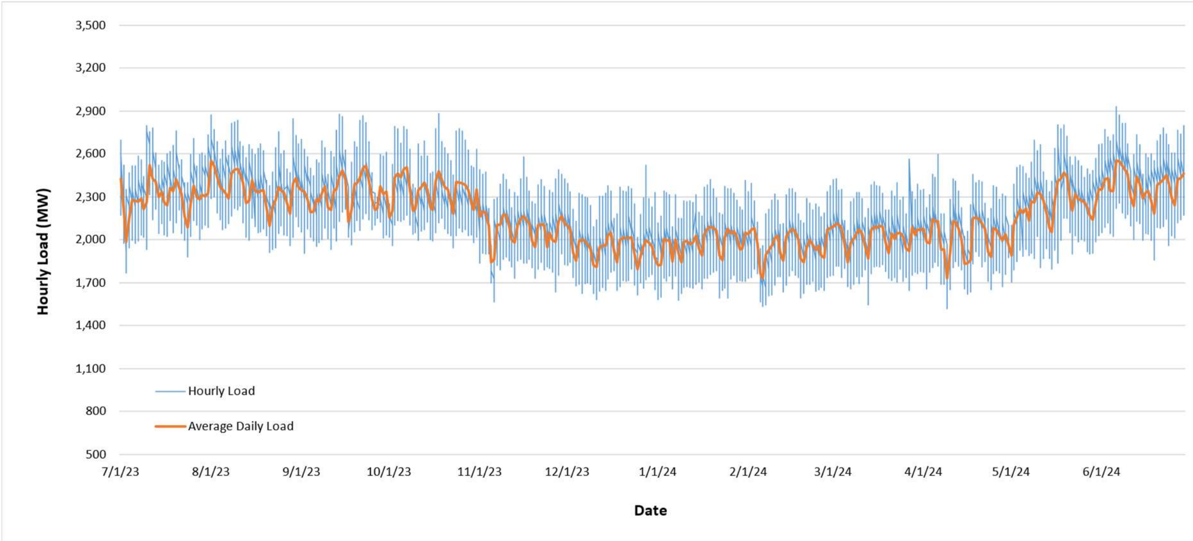
The electrical demand, also referred to as load, is another important element in resource adequacy evaluations, specifically because system generators must be able to meet the electrical demand for every hour. Puerto Rico's electrical demand varies for each hour of the day, throughout the year. The Puerto Rico load profile considered for the resource adequacy calculations described in this report is equal to the actual metered load values from 2022, with various adjustments to correct for times when metered data was unavailable or reflected abnormal operating conditions – namely the time period during and in the immediate aftermath of Hurricane Fiona. Adjustments were made to the 2022 load data using the historical load data from 2021.

The following figure plots the load profile used for each hour in the analysis of FY2024. Some key attributes to note about the load profile are both the hourly variability and the seasonality of the profile, with summer and early fall months having higher load than other times during the year. The reason for this is that summer and the early fall months are the hottest in Puerto Rico; thus, electrical consumption from air conditioning and other cooling tends to drive up total system electrical usage.[20]

[19] Note that based on NERC Standard BAL-502-RF-03, BTM resources should not counted as a contribution towards resource adequacy. It is recommended that future resource adequacy analyses of the island either consider a probabilistic methodology of accounting for a dependable MW level of these resources or conservatively ignore their contributions

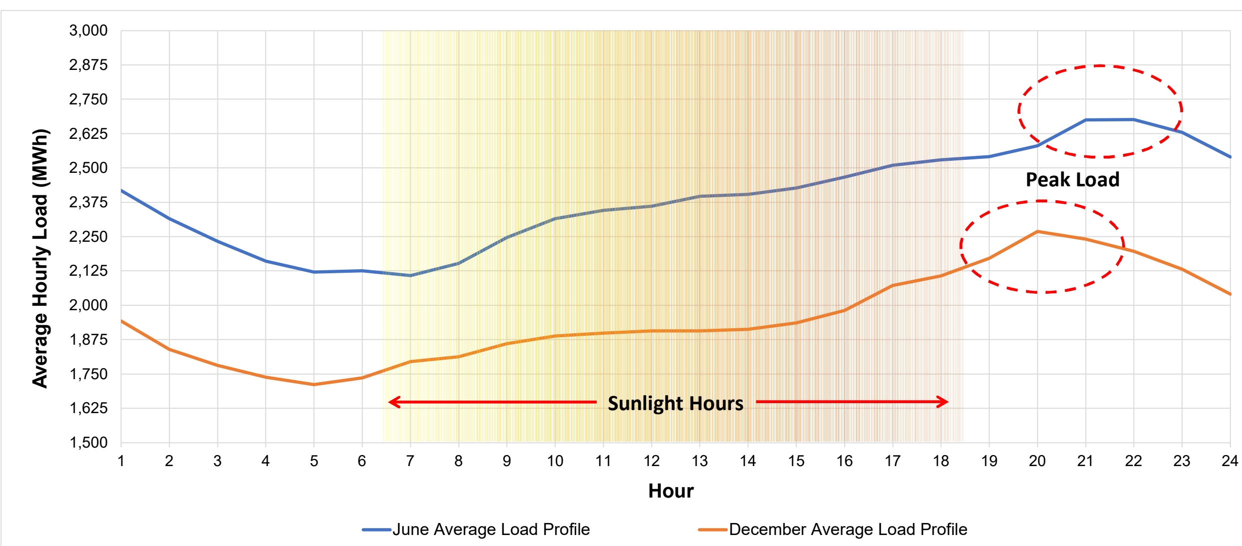
[20] For future analyses it is recommended that a statistical approach to load forecasting based on weather data be considered. A methodology that considers a distribution of potential system loads levels based on Puerto Rico's historic weather data would better capture potential load variability for the island and its impact to resource adequacy.

Figure 2-1: Load Profile Used for the FY2024 Resource Adequacy Analysis



An important characteristic of the load profile in Puerto Rico is how it varies over the different hours of the day. The following figure illustrates this variance by presenting hourly load profile, averaged over each day, for the months of June 2022 and December 2022 (the highest and lowest load months, respectively). As can be observed in the figure, load steadily rises over the course of the day, peaking in the evening. From a resource adequacy perspective, the hourly load profile is important because it identifies when generation is needed most. The fact that the load profile peaks in the evening also highlights a challenge that many other utilities with large amounts of solar generation are currently facing: stand-alone solar power plants are unable to contribute generation to help meet the evening peak since the sun would have already set. Solar power resources must be paired with energy storage in order to contribute generation during the evening peak. The size and duration of the storage systems is an important consideration in determining if solar resources will contribute to resource adequacy at peak.

Figure 2-2: Resource Adequacy Analysis Load – Hourly Averages



The load, and/or the hourly load profile, in Puerto Rico may change moving forward. On one hand, energy efficiency plans, demand reduction programs, the growth of BTM generation, and other similar items have the potential to reduce overall system load; however, other items such as electric vehicle adoption have the potential to increase system load. For this reason, continued identification of the critical times during the day and over the course of the year when load is high will be important moving forward for resource adequacy considerations.

2.3 Puerto Rico's Reserve Margin

A comparison of the forecasted electric demand in Puerto Rico, which peaks at approximately 3,000 MW, to the total nameplate generation capacity of the Puerto Rico electric system, which averages near 5,000 MW, indicates that the PRM for Puerto Rico is approximately 67% (1 – 5,000 MW / 3,000 MW). In general, this PRM is in line with, or even higher than, other similarly sized islands. For example, in Hawaii, HECO reported that on Oahu the margin of available capacity to peak load was approximately 42% in 2022.[21]

Given the fact that Puerto Rico's PRM is generally in line with, or even higher than, other similarly sized islands (many that achieve high performance with respect to resource adequacy), one might draw the conclusion that resource adequacy is not a significant challenge in Puerto Rico. This thinking is mistaken. The reason for this is that a focus on PRM from one location to another ignores location-specific variables that can have a significant impact on the ability for a utility to serve load in the location. For example, in Hawaii the generator forced outage rates are significantly lower than in Puerto Rico. As a result, generators in Hawaii are able to operate much more reliably with fewer generator outages than those in Puerto Rico. NERC notes this fact in *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning:*[22]

> Unless the Planning Reserve Margin is derived from an LOLP (loss of load probability) study, there is no way to know what level of system risk is present. This is because some generators have higher forced outage rates than others. Therefore, one system with a 15 percent Planning Reserve Margin may not be as reliable as another system even though it also has a 15 percent Planning Reserve Margin.

As a result, given the high outage rates and derates of the existing power plants in Puerto Rico, a simple comparison of the PRM in Puerto Rico to the PRM values in other similar locations masks the significant challenges Puerto Rico faces on a daily basis with respect to generation resource adequacy. It is correct that there is a substantial amount of generation installed in Puerto Rico; however, the majority of that generation is unreliable and too frequently incapable of operating when electricity is needed.

The methodology utilized in this report to assess resource adequacy for Puerto Rico is based on the probabilistic approach. As NERC noted in their survey of various planning regions and utilities, "most assessment areas are already using or are considering probabilistic approaches to assess emerging reliability issues."[23]

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[21] Hawaiian Electric Company Inc., Adequacy of Supply, 31 January 2023.
[22] North American Electric Reliability Corporation, Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning, March 2011.
[23] North American Electric Reliability Corporation, Probabilistic Adequacy and Measures, July 2018.

3.0 Resource Adequacy Analysis Results and Implications

Resource adequacy analyses of the Puerto Rican electric system were performed using the PRAS model, a probabilistic resource adequacy simulation tool adapted for the Puerto Rico electrical system. The methodology followed for all calculations is consistent with the descriptions provided in the previous sections of this report (also see Appendix 2 for a more detailed explanation of the calculation framework and equations). The goal of the calculations was to quantify Puerto Rico's electrical system performance and to establish a baseline set of resource adequacy measures for the existing electrical system, which would then allow for comparison to other similar planning regions and utilities and help guide system planning decisions.

A thorough validation of the PRAS model was documented in Appendix 7 of LUMA's *FY2023 Puerto Rico Electrical System Resource Adequacy Analysis* report.

3.1 Resource Adequacy Results

FY2024 was simulated on an hourly basis to calculate if there is sufficient available generation capacity to meet load for each hour of the day. Since forced outages to power plants occur randomly, FY2024 is re-simulated 2,000 times, with each simulation considering forced outages occurring at different times. The results of the analysis are presented both in this section and also in greater detail in Appendix 11 through Appendix 14.

Considering that as an island, Puerto Rico is unable to rely on electricity imports to support grid stability, and that the island's generators are generally unreliable, Puerto Rico faces challenges in meeting industry standard resource adequacy risk targets. This analysis confirmed this reality, as the probability that Puerto Rico's generators would be unable to meet system load over the course of a year was calculated to be nearly 100%.[24] In addition, the LOLE in Puerto Rico was calculated to be 37.5 days/year, indicating that on average, one can expect a generation shortfall (i.e., "loss of load") to occur 37.5 days in FY2024. This LOLE is significantly higher than other LOLE targets adopted in the energy industry, including those adopted by similar islands. For reference, this calculated LOLE is 375 times higher than a commonly accepted 1 day in 10 years LOLE industry standard (0.10 days per year). The following table summarizes the results of the analysis.

[24] Loss of load probability, LOLP, calculated based on 2,000 Monte Carlo simulations (i.e., in approximately 100% of the simulations, a loss of load event occurred).

Table 3-1: Calculated Resource Adequacy Risk Measures, Current System (FY2024)

Measure	Loss of Load Expectation (LOLE)	Loss of Load Hours (LOLH)
Average	37.5 Days / Year	194.5 Hours / Year
Industry Benchmark Target	0.1 Days / Year	—
Distribution Standard Deviation	7.1 Days / Year	50.2 Hours/ Year
Distribution Maximum	63 Days / Year	407 Hours / Year

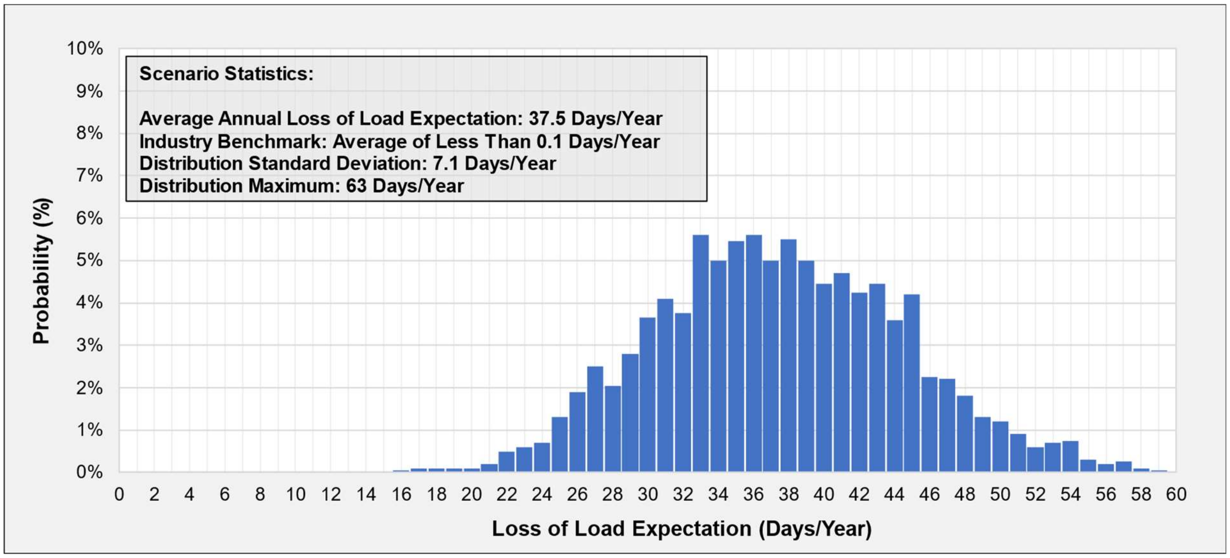
As expected for a small islanded system, the analysis demonstrates that outages to individual generators, whether planned or unplanned, have a significant impact on the electrical system's ability to reliably meet load. For comparison, a large U.S. mainland utility or planning region with hundreds of generators is more easily able to manage outages to individual generators given that there are many other available generators that can be brought online to make up for the lost generation.

3.1.1 Loss of Load Expectation Distribution Review

As previously mentioned, the average LOLE of 37.5 days per year is significantly higher than the standard industry benchmark of 0.10 days per year. An equally important item to note is the high standard deviation in the LOLE results. For all simulations the LOLE was greater than 16 days per year. The figure below presents this information, organizing the results of the simulations for FY2024.

Based on the distribution, 37.5 days of loss of load is the most likely outcome. There is approximately a 50% probability that the number of days of loss of load will be equal to or greater than 38 days. The analysis results do not forecast what will actually occur with respect to resource adequacy in FY2024; however, the results do help to quantify the risk, or probability, of how many loss of load days might be expected in FY2024. Note that one simulation had 63 days of loss of load, which was the highest of all the simulations performed.

Figure 3-1: Loss of Load Expectation Probability Chart, FY2024



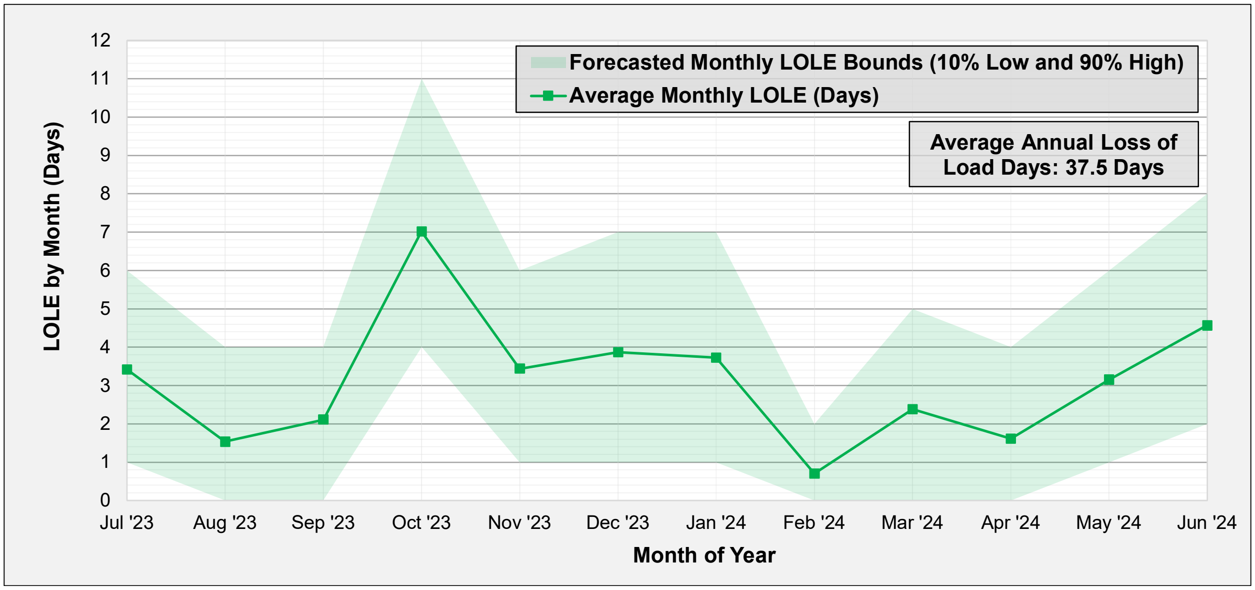
Various characteristics of the Puerto Rico electric system help explain the wide distribution in LOLE:

- The forced outage rates for the existing power plants are generally very high, meaning the power plants break down frequently. If different power plants happen to break down at the same time, which is common in Puerto Rico, then there is significant risk that there will not be enough remaining generators available to cover the load. As power plants go offline for outages (whether planned or forced), the remaining power plants must increase output to meet system load. This places some level of additional stress on the remaining power plants, which can compound the risk of loss of load for the system – specifically if the stress on the remaining power plants results in them breaking down more frequently or requiring them to take more frequent planned maintenance.
- In addition, the power plants in Puerto Rico sometimes require prolonged planned maintenance outages due to their poor current condition. Whenever a power plant is on a planned maintenance outage, it is unable to generate electricity.
- As a relatively small island, Puerto Rico is both unable to import electricity from neighbors, and has a limited number of power plants that can generate electricity. By comparison, a larger utility on the U.S. mainland can not only import electricity from neighboring utilities during times of need, but also has many available power plants that can be started or ramped up to meet load in times of need. In Puerto Rico, the loss of a single large power plant (either for planned maintenance or a forced outage), like EcoElectrica, the Aguirre Steam units, Costa Sur, or AES, immediately reduces the total available generating capacity in Puerto Rico by roughly 10%. If one of these units is out of service, electricity must be supplied by other generators, many of which are either already being fully utilized, or are unreliable and break down frequently.

The following figure shows LOLE (for all 2,000 simulations) broken out by month. The dark line represents the average calculated LOLE, while the shading around the middle line represents the calculated monthly LOLE distribution's 10% low and 90% high values for each month – the shading provides an illustration of the range of calculated potential LOLE outcomes for each month. For example, for the month of October 2023, the calculated average LOLE was approximately 7 days, with the worst 10% of simulations having 11 or more days of load shed, while the best 10% of simulations having 4 or less days of load shed. As a result, one might expect load shed for the month of October 2023 to fall somewhere between the range of 4 days to 11 days, with 7 days being the most likely outcome.

LOLE was found to be highest during October 2023, December 2023, January 2024, and June 2024. The months of October, December, and January have a high number of planned maintenance outages to the major generators. During maintenance outages of large generators, any additional forced outages to other generators could result in island load shed. In general, while planned outages to large generators can result in higher load shed risk, it is difficult to reschedule outages to large generators in Puerto Rico in a different way that would result in a significant improvement to the annual resource adequacy performance of the system. The reason for this is because there are only so many times when the generators can be scheduled to minimize the impact to the system and the generators often require extended maintenance time due to their age and condition. LOLE for the month of June is mainly due to the high system peak demand.

Figure 3-2: Calculated Loss of Load Expectation Broken Out by Month of the Year



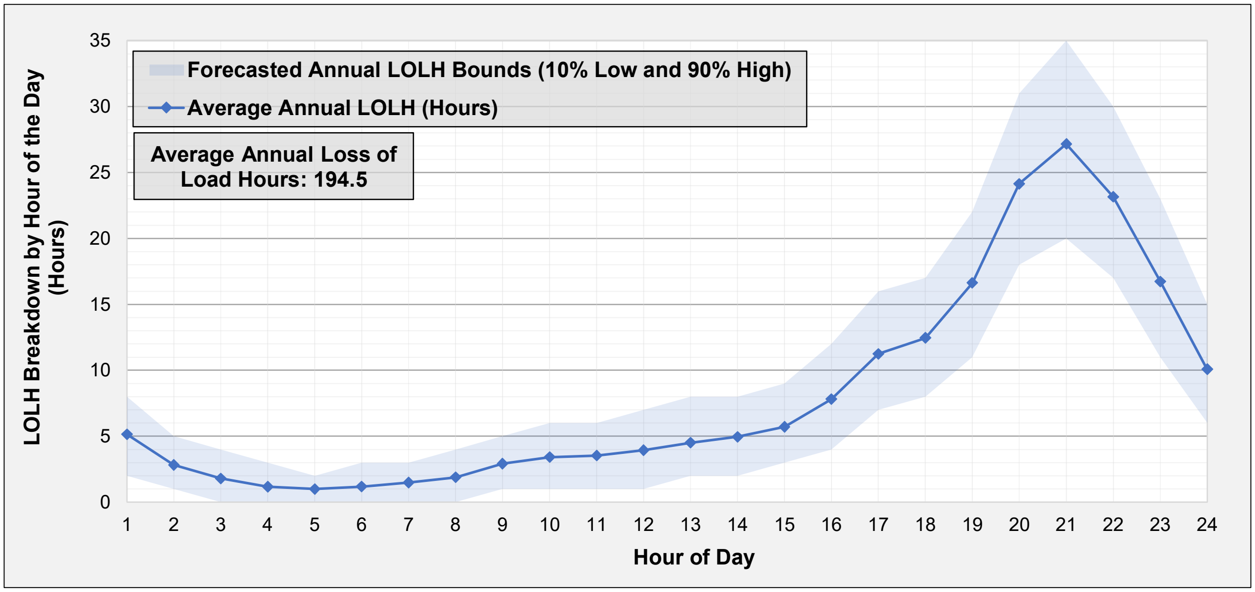
3.1.2 Loss of Load Hours Breakdown

The following figure presents the average number of LOLH (for all the 2,000 simulations), broken out by hour of the day. In the figure, if one were to sum each individual hour, it would total 194.5 LOLH, which is the average annual LOLH over all the simulations. Similar to the previous figure, the shading represents the calculated annual LOLH distribution's 10% low and 90% high values for each hour – the shading provides an illustration of the range of calculated potential LOLH outcomes for each hour over the course of the year. The majority of LOLH are observed during the evening hours, when system load is highest and when solar production is diminished or unavailable to the electric system. Approximately 62% of the observed LOLH in the resource adequacy simulation were observed to occur from 6 p.m. and 11 p.m.

From the perspective of improving system resource adequacy (i.e., reducing LOLE), the results indicate that the most effective solutions will be those targeted at being able to help meet load during the evening peak. For example, additional stand-alone solar generators should be able to help overall system resource adequacy, but only during times when the sun is up, which reflects just over a third of the hours when the simulated LOLH were found to occur. As such, the results illustrate that additional standalone solar generators will have little impact on improving LOLE. The reason for this is because if there was a generation shortfall event that spanned an entire day (i.e., a forced outage to a large thermal generator), additional solar would help to mitigate potential loss of load during the middle of the day (and thus reduce mid-day LOLH), but during the evening the generator shortfall event would still drive load shed since the solar is not able to generate after the sun has set (a single hour of load shed, LOLH, regardless of when it occurs, equates to a day LOLE). In other words, the additional standalone solar might be able to prevent the load shed event from occurring mid-day, but it would not be able to prevent it from occurring in the evening; thus, the additional standalone solar would not be able to significantly help improve system LOLE.

In contrast, an energy storage system, reciprocating engine, or other dispatchable unit would be better able to provide energy during the evening peak load; thus, would be most effective at improving overall system resource adequacy.

Figure 3-3: Calculated Loss of Load Hours Broken Out by Hour of the Day



3.1.3 Calculated Reserve Margins

The following figure illustrates the average system reserve margins by hour and month, based on an average over all the simulations performed (i.e., the values shown represent the middle of the distribution). Each value in the figure reflects the MW of available capacity during that hour and month. Available capacity includes both the available capacity of thermal generators and any dependable capacity from the operating renewable generators.

Times that correspond to higher LOLH risk are highlighted in various shades of red, the darkest times corresponding to highest LOLH risk. The values in the table are the average over all simulations. In general, times when the available capacity drops below 500 MW correspond to a higher risk of demand not being served in Puerto Rico. Under this threshold, the loss of a single large generator can result in a shortfall of generation to meet demand. The average available capacity to load is lowest in the evening hours when system load is highest.

The figure illustrates that while the PRM in Puerto Rico is approximately 67%, due to high forced outage rates of the generators on the island, the ratio or actual available capacity to load is substantially lower.[25]

[25] A recommended PRM was not determined as this report instead focused on assessing the current resource adequacy performance on the island. It is recommended that future versions of this analysis consider what PRM (or similar metric) Puerto Rico should target.

Figure 3-4: Capacity Reserve Margin

Month of Year

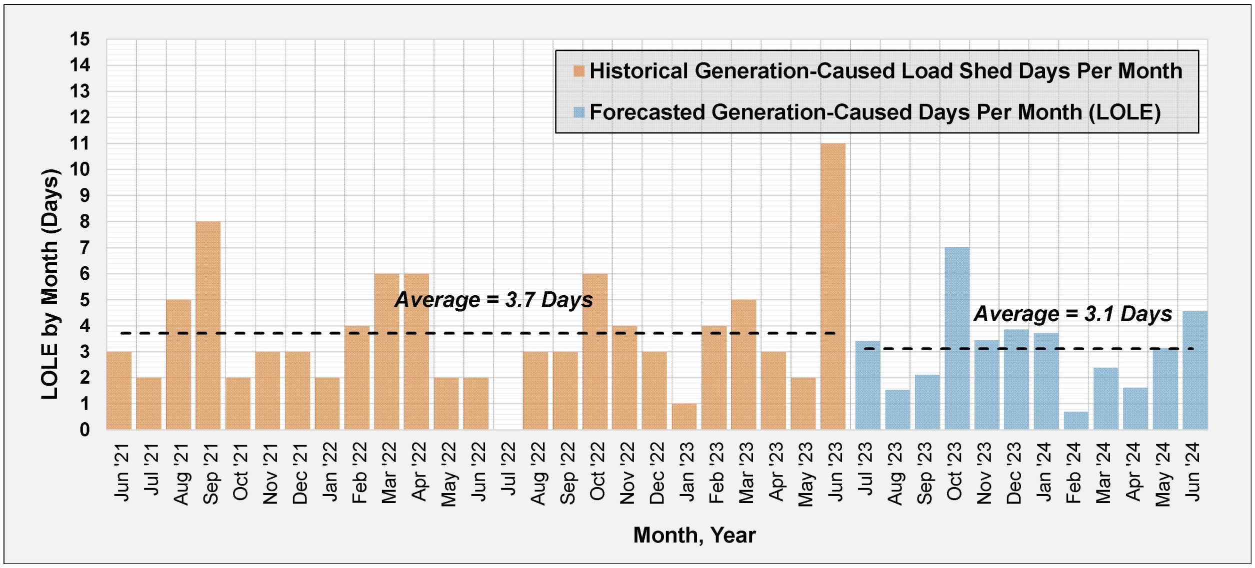
Hour of Day	Jul '23	Aug '23	Sep '23	Oct '23	Nov '23	Dec '23	Jan '24	Feb '24	Mar '24	Apr '24	May '24	Jun '24	Average
1	698	895	882	655	707	706	676	1,017	850	856	779	640	**780**
2	807	987	971	730	786	809	784	1,105	946	955	863	743	**874**
3	881	1,064	1,038	785	848	868	851	1,173	1,018	1,034	947	824	**944**
4	935	1,120	1,081	819	910	911	900	1,219	1,071	1,074	1,003	898	**995**
5	964	1,156	1,108	831	938	938	913	1,217	1,099	1,099	1,046	938	**1,021**
6	964	1,153	1,092	797	922	912	897	1,220	1,064	1,096	1,020	933	**1,006**
7	971	1,134	1,069	781	847	853	857	1,133	1,001	1,058	1,019	951	**973**
8	938	1,126	1,056	748	846	836	826	1,101	984	1,029	972	913	**948**
9	883	1,063	996	668	803	794	777	1,060	936	987	917	846	**894**
10	857	1,022	952	624	772	797	745	1,042	916	972	888	826	**868**
11	862	1,019	936	608	779	822	737	1,031	930	982	890	842	**870**
12	867	1,014	895	571	766	837	737	1,042	928	957	888	865	**864**
13	874	1,000	886	553	739	840	711	1,044	911	959	887	842	**854**
14	872	983	864	521	722	830	719	1,040	924	967	883	839	**847**
15	837	948	834	494	699	810	704	1,020	901	955	840	787	**819**
16	788	888	794	446	641	747	647	986	869	898	775	704	**765**
17	728	848	760	416	568	623	580	916	789	826	694	615	**697**
18	671	829	745	417	545	565	528	875	743	780	660	571	**661**
19	644	810	709	314	477	483	487	829	700	749	631	540	**614**
20	596	713	617	290	420	382	375	711	574	653	566	489	**532**
21	465	634	601	301	427	408	384	723	559	609	477	391	**498**
22	468	637	634	352	453	453	447	760	588	641	491	384	**526**
23	508	699	704	437	511	518	496	815	650	682	543	429	**583**
24	581	781	796	553	602	609	569	907	718	757	639	519	**669**
Average	**778**	**938**	**876**	**571**	**697**	**723**	**681**	**999**	**861**	**899**	**805**	**722**	**796**

3.1.4 Comparison of Forecasted FY2024 Loss of Load Expectation to Historical Data

The following figure compares the historic number of generation shortfall-caused load shed days per month (between June 2021 and May 2023) to the previously presented monthly LOLE forecast for FY2024. As can be observed in the figure, the historical and forecasted values show reasonably close alignment; thus, there is not expected to be a noticeable improvement in the frequency load shed in FY2024 as compared to recent historical performance.

Both in the forecast for FY2024 and in the recent historical data, the average number of days of generation-caused load shed is above 3 days per month.

Figure 3-5: Comparison of Monthly Historical and Forecasted Loss of Load Expectation



Note: The above plot compares load shed that occurs over the course of "normal" system operation. Load shed for September 2022 after September 18th are not included in the above plot. This is because load shed for this month was primarily driven by the damage caused by Hurricane Fiona, which was an event that was beyond what is considered to be the "normal" operation of the system. The large number of days of load shed in June 2023 were driven primarily by a combination of very high temperatures (and thus high electrical demand) and generator outages.

3.2 Sensitivity Analyses

A number of additional sensitivity analyses are described in Appendix 16 through Appendix 27 of this report. A list of those additional analyses is provided below:

1. **Current System (Expected Case).** Baseline model based on system operation in FY2024. This scenario reflects the baseline comparison to all of the additional sensitivity analyses listed below. Puerto Rice has a relatively small number of total generators available to be dispatched at any point in time. As a result, it is frequently at a high risk of not being able to serve load in the event of a loss of a large generator due to the simple fact that there is a limited number of other generators that could be dispatched to cover for the large generator's outage. Also, the forced outage times of the other generators have historically been much longer than expected. Results from this scenario are described in Appendix 11 through Appendix 14.
2. **New Emergency Generation.** This sensitivity analyzes the operational impact of adding various amount of emergency generation, totaling 150 MW, 350 MW, and 700 MW. There is no emergency generation included in the base case analysis due to the uncertainty of how long it will remain. The emergency generation is modeled as operational for the entire fiscal year. In addition to helping improve overall system resource adequacy, one of the key benefits of additional emergency generation is it would allow the existing baseload generators to be temporarily taken offline for much needed maintenance.
3. **Early Retirement of the AES Coal Power Plant.** This sensitivity simulation illustrates the resource adequacy impact of the early retirement of the AES Coal Power Plant from the current system model. Also investigated is the impact of the early retirement of the AES Coal Power Plant along with the addition of the Tranche 1 projects (845 MW of new solar generation paired with 220 MW of 4-hr duration BESS).
4. **Meeting Industry LOLE Benchmarks.** This sensitivity simulation determines how much additional 'perfect' generation capacity would need to be added to the Puerto Rico electrical system in order for an LOLE target of 0.10 days/year to be met. For reference, 'perfect' generation capacity is equivalent to a generator that can operate 100% of the time, for every hour of the year. Equivalently, it can be considered as a constant MW reduction in load for every hour of the year. The goal of this simulation is to quantify the generation shortfall in Puerto Rico. While no generator is "perfect," identifying how many MW of perfect capacity are needed helps to provide a best-case estimate of what would be required in terms of generation (or load reduction) to bring Puerto Rico in line with a 0.10 days/year LOLE target.
5. **New Solar Addition.** This sensitivity simulation illustrates the impact of adding 845 MW of new solar generation to the current system model. For this sensitivity, all added solar is assumed to be standalone solar, meaning none of the MW are considered to be paired with energy storage. Separate sensitivity simulations which consider energy storage are listed below.
6. **New Standalone BESS Addition.** This sensitivity simulation illustrates the impact of adding 220 MW of 4-hr duration standalone battery energy storage systems (BESS) to the current system model.
7. **New Solar Paired with BESS Addition.** This sensitivity simulation illustrates the impact of adding 845 MW of new solar generation paired with 220 MW of 4-hr duration BESS to the current system model. The total amount of added solar and BESS resources added for this simulation are consistent with the total amounts from the Tranche 1 projects.
8. **New Flexible Combined Cycle Thermal Resource.** This sensitivity simulation illustrates the impact of adding a new 330 MW combined cycle resource to the current system model.
9. **New Flexible Combustion Turbine Thermal Resources.** This sensitivity simulation illustrates the impact of adding a fleet of new, smaller flexible combustion turbine thermal resources to the current system model. A total of 11 new 21 MW resources (231 MW total) are added for this simulation.

10. **Additional Distributed Solar Resources.** This sensitivity simulation adds 250 MW of distributed solar PV to the system in order to estimate the associated resource adequacy impact.
11. **New Demand Response Resources.** This sensitivity simulation illustrates the resource adequacy impact of adding demand response (DR) resources (i.e., short-term reductions in system load) to the current system model in varying MW levels.
12. **Load Sensitivity.** This scenario investigates the impact of lower system load on system resource adequacy.
13. **Addition of Electric Vehicle Load.** This scenario examines the resource adequacy impact of increasing levels of electric vehicle penetration in Puerto Rico.
14. **Effective Load Carry Capability.** A set of appendices are provided at the end of this report that explain the concept of ELCC and perform ELCC calculations for solar PV, energy storage, and solar PV paired energy storage resources in Puerto Rico.

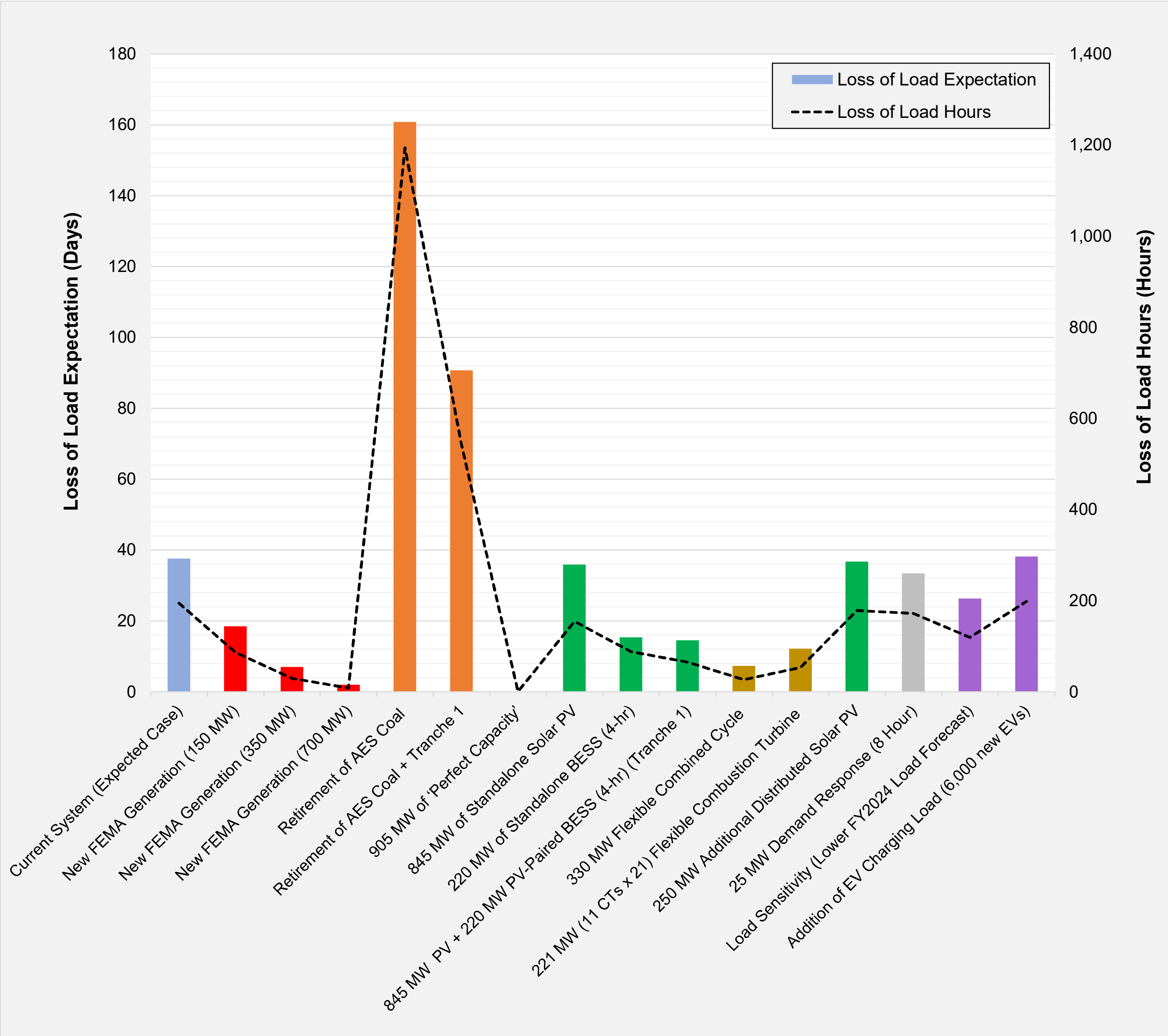
The following table summarizes the LOLE and LOLH model results for the various sensitivity analyses performed.

Table 3-2: Calculated Resource Adequacy Risk Measures – All Sensitivity Cases

<table>
<tr><th colspan="2">Scenario</th><th>Loss of Load Expectation (LOLE), Days / Year</th><th>Loss of Load Hours (LOLH), Hours / Year</th></tr>
<tr><td colspan="2">Current System (Expected Case)</td><td>37.5</td><td>194.5</td></tr>
<tr><td rowspan="13">Current System +</td><td>New Emergency Generation (150 MW)</td><td>18.5</td><td>86.5</td></tr>
<tr><td>New Emergency Generation (350 MW)</td><td>7.0</td><td>29.4</td></tr>
<tr><td>New Emergency Generation (700 MW)</td><td>2.0</td><td>8.5</td></tr>
<tr><td>Retirement of AES Coal</td><td>160.8</td><td>1,193.6</td></tr>
<tr><td>Retirement of AES Coal + Tranche 1 (845 MW Solar PV + 220 MW 4-hr BESS)</td><td>90.7</td><td>542.6</td></tr>
<tr><td>905 MW of ‘Perfect Capacity’</td><td>0.1</td><td>0.3</td></tr>
<tr><td>845 MW of Standalone Solar PV</td><td>35.9</td><td>154.6</td></tr>
<tr><td>220 MW of Standalone BESS (4-hr)</td><td>15.4</td><td>87.8</td></tr>
<tr><td>845 MW Solar PV + 220 MW Solar-Paired BESS (4-hr) (Tranche 1 Projects)</td><td>14.5</td><td>65.1</td></tr>
<tr><td>330 MW Flexible Combined Cycle</td><td>7.3</td><td>26.5</td></tr>
<tr><td>221 MW (11 CTs x 21) Flexible Combustion Turbine</td><td>12.1</td><td>53.3</td></tr>
<tr><td>250 MW Additional Distributed Solar PV</td><td>36.7</td><td>178.4</td></tr>
<tr><td>25 MW Demand Response (8 Hour)</td><td>33.4</td><td>172.1</td></tr>
<tr><td colspan="2">Load Sensitivity (Lower FY2024 Load Forecast)</td><td>26.3</td><td>119.2</td></tr>
<tr><td colspan="2">Addition of Electric Vehicle Charging Load (6,000 new EVs)</td><td>38.2</td><td>198.0</td></tr>
<tr><td colspan="2">Industry Benchmark Target</td><td>0.1</td><td>—</td></tr>
</table>

The figure below illustrates the LOLE and LOLH for all scenarios.

Figure 3-6: Scenario Loss of Load Expectation and Loss of Load Hours



Appendix 1. Resource Adequacy Risk Measures Introduction

The key reliability measures for the purposes of this analysis are presented in the table below. Each measure represents different aspects of a system's resource adequacy including the frequency, duration, and magnitude of generation shortfall events.

Table A-1: Resource Adequacy Risk Measures

Resource Adequacy Risk Measure	Definition
Loss of Load Hour (LOLH)	The expected number of hours within a given time horizon (usually one year) when a system's hourly demand is projected to exceed the available generating capacity for that hour.
Loss of Load Expectation (LOLE)	The expected number of days in the time horizon (usually one year) for which available generation capacity is insufficient to serve demand. LOLE measures the number of days in which involuntary load shedding occurs, regardless of the number of consecutive or non-consecutive LOLHs in the day. For example, if there are two days in a year where there is insufficient generation to serve load (regardless of the duration of the outage or how many events occur in a single day), then LOLE would equal two days per year.
Loss of Load Probability (LOLP)	The probability of demand exceeding the available generation capacity during a given period.
Expected Unserved Energy (EUE)	The summation of the expected number of megawatt (MW) hours (MWh) of load that will not be served in a specific time interval because of demand exceeding the available generation capacity. This energy-centric measure considers the frequency, magnitude, and duration for all hours of the period.

The measures identified above are used to quantify a system's resource adequacy performance, allowing one to compare performance to a benchmark performance target or other locations. The mathematical definitions of the above measures are provided in the following appendix.

Appendix 2. Resource Adequacy Risk Measures Calculations

Resource adequacy risk measures are used by system planners to identify future needs and inform decision-making. When determining the optimum level of generating resources, system planners may consider financial costs, environmental impacts, technology types, market designs, or other drivers. This report references NERC's 2018 *Probabilistic Assessment and Measures Report*[26] as the basis for the selection of the probabilistic resource adequacy risk measures, including recommended computational approaches and definitions. For this report, a Monte-Carlo computational method was used to calculate LOLE and LOLH, computing all hours (8,760) of the FY2024 study year (July 1, 2023, until June 30, 2024).

The resource adequacy risk measures are used to quantify the loss of load, or amount of demand not served, to evaluate system resource adequacy. Loss of load at hour *i* in the *kth* Monte Carlo iteration is defined as follows:

$$LOL_{ki} = \max\{0, L_i - \sum_{Gen=j}^{m} G_{jk}\}$$

Where L_i is the load in hour *i*, G_{jk} is the available capacity of the *jth* generator in the *kth* Monte Carlo iteration, and *m* is the number of generators in the system. LOL_{ki} is the loss of load amount in hour *i*, in the *k*th iteration (in MW).

Loss of Load Hours

LOLH is defined as the expected number of hours per year when a system's hourly demand is projected to exceed the generating capacity. LOLH is calculated by counting the number of hours where there is loss of load in each iteration:

$$LOLH_k = \sum_{Hour\ i=1}^{H} B_{ki}$$

Where $LOLH_k$ is the loss of load duration in the *kth* iteration, *i* represents each hour, *H* is the total number of hours in the study period (8,760), and B_{ki} is a Boolean variable representing whether there is demand not supplied in hour *i* in the *kth* iteration, defined below:

$$B_{ki}(LOL_{ki}) = \begin{cases} 0 \ if \ LOL_{ki} = 0 \\ 1 \ if \ LOL_{ki} \neq 0 \end{cases}$$

LOLH for the entire simulated year can then be calculated using the following equation:

$$LOLH = \frac{1}{N}\sum_{k=1}^{N} LOLH_k$$

[26] North American Electric Reliability Corporation, Probabilistic Adequacy and Measures, July 2018.

Where *k* represents the Monte Carlo iteration and *N* is the total number of Monte Carlo iterations.

Loss of Load Expectation

LOLE counts the days that have loss of load events, regardless of the number of consecutive or non-consecutive LOLH in the day. For example, if there is one LOLH in a day, or two LOLH in a day, both equate to 1 day of loss of load from an LOLE perspective. LOLE is the expected number of days per year for which available generation is insufficient to serve demand at least once per day.

$$LOLE\ days/year = \frac{1}{N}\sum_{k=1}^{N}\sum_{d=1}^{D} E_{k,d}$$

Where *d* represents the day, *D* is the total number of days, *k* is the Monte Carlo iteration, *N* is the total number of Monte Carlo iterations, and $E_{k,d}$ is a Boolean variable describing whether there is at least one LOLH in the day:

$$E_{ki} = \begin{cases} 0\ if\ LOLH_{kd} = 0 \\ 1\ if\ LOLH_{kd} \neq 0 \end{cases}$$

Where $LOLH_{k,d}$ is the loss of load duration for a day of each iteration, the calculation equation is shown below:

$$LOLH_{kd} = \sum_{Hour\ i=1}^{H_d} B_{ki}$$

Where *i* is a variable representing each hour, B_{ki} is the Boolean variable (defined above) representing whether there is demand not supplied in hour *i,* in the *kth* iteration, and H_d is the total number of hours in the day being evaluated.

Expected Unserved Energy

EUE is the total amount expected MWh of demand that will not be served in a given period, calculated based on how much demand exceeds available capacity across all hours. As a result, EUE is an energy-centric metric that considers the magnitude and duration for all hours of the period analyzed. It is calculated in MWh. EUE is calculated in this report using the following formula:

$$EUE = \frac{1}{N}\sum_{k=1}^{N} ENS_k$$

Where ENS_k is the energy not supplied in the *kth* Monte Carlo iteration, and *N* is the total number of Monte Carlo iterations. In the results of this report, we also report the average hourly EUE whenever there is a LOLH (i.e., the average amount of MWs of capacity shortfall in the hour).

Appendix 3. Resource Adequacy – Regional Considerations

A comparison of resource adequacy approaches for various other utilities and planning entities that have similarities to Puerto Rico is provided in this appendix. Utilities and planning entities considered in this review were selected based on having similar characteristics to Puerto Rico, including other islands, similar geographic location and climate, and similar renewable integration goals.

Resource Adequacy for Other Islands

Maintaining high levels of system resource adequacy is especially challenging for islanded systems. The main reason for this is that islands are not able to import electricity from neighboring utility systems during times of peak demand and/or deficient generation capacity. In contrast, a utility on the U.S. mainland would generally be able to import electricity from neighbors when needed. In addition, many islands, including Puerto Rico, have a relatively small number of total generators available to be dispatched at any point in time. As a result, islands are often at a high risk of not being able to serve load in the event of a loss of a large generator, due to the simple fact that there is a limited number of other generators that could be dispatched to cover for the large generator's outage. In contrast, planning regions and large utilities in the U.S. mainland can have hundreds, and sometimes thousands, of other generators that could be dispatched to cover for power plant outages.

U.S. Virgin Islands

As one of Puerto Rico's island neighbors, the U.S. Virgin Islands has several similarities to Puerto Rico from a generation resource adequacy perspective. Neither can import electricity from neighbors (as would be the case on the U.S. mainland), both have similar climates, and both have similar renewable energy goals. The utility that operates the electrical system for the U.S. Virgin Islands, the Virgin Islands Water and Power Authority (VIWAPA), released an updated IRP in 2020 where they discussed several items related to the resource adequacy considerations for the Virgin Islands.[27] The IRP planning horizon spanned 2020–2044 and notes the requirement that 50 percent of electricity generation in the U.S. Virgin Islands (as a percentage of peak demand) must come from renewable resources by 2044. VIWAPA's resource adequacy planning criteria sets a loss of load target of 1 day per year in 2024, which gradually reduces to 0.10 days per year by 2044. In addition, VIWAPA has an "N-1-1" planning criterion, which requires sufficient installed generation capacity to be available during the loss of two of the largest generators, or key transmission lines.

Hawaii

From generation resource adequacy perspective, Hawaii also has several similarities with Puerto Rico. They cannot import electricity from neighbors, have similar climates, and both are undergoing the integration of more renewable resources. The Hawaiian Electric Company (HECO) operates the electrical system in Hawaii. HECO updated its resource adequacy considerations which are summarized in a filing with the Hawaiian Public Utility Commission, titled the 2021 Adequacy of Supply.[28] In the filing, HECO

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[27] VIWAPA Final IRP Report, 21 July 2020.
[28] Hawaiian Electric Company Inc., Adequacy of Supply, 29 January 2021.

notes some recent modifications to their resource adequacy planning criteria, namely the implementation of an ERM concept for the purposes of examining resource adequacy in all hours of the year. The ERM is defined as the percentage of excess system capacity over system load in each hour and accounts for Hawaii's inability to import emergency power from a neighboring utility. The ERM is rooted in HECO's guideline of requiring the system LOLE to be less than one day per 4.5 years.

The ERM concept being used by HECO includes contributions from variable renewable generators, energy storage, demand reduction programs, and other similar resources. HECO defines the dependable contributions from renewable generators to resource adequacy probabilistically, based on the following equation:

$$Dependable\ Capacity_{Hourly} = Average\ Generation_{Hourly} - N \cdot (Standard\ Deviation)$$

Here the hourly dependable capacity of the renewable generator is equal to that generator's historical production for that hour, reduced by the standard deviation of the historical production. The value of *N* is set by HECO to be 1 for wind generators and 2 for solar generators. For example, if a solar power plant on average has generated 100 MW at noon, but with a standard deviation of 20 MW, then only 60 MW would be considered as dependable capacity (100 MW – 2 x 20 MW = 60 MW) at noon.

Guam

Guam's electrical system is operated by the Guam Power Authority. As an island with a similar climate to Puerto Rico, Guam shares many similar resource adequacy challenges as Puerto Rico. Guam Power Authority is currently undertaking the process to develop an updated IRP; however, previous IRP filings note the island targets a one day per 4.5 years LOLE resource adequacy risk measure.[29] Guam Power Authority indicates that at least a 60% PRM is required to meet this level of resource adequacy. Guam Power Authority also utilizes an "N-2" planning criteria, requiring sufficient generation to cover the loss of the island's two largest generating sources.

Resource Adequacy for Other U.S. Locations Near Puerto Rico (Non-Islands)

Additional comparisons of non-island, U.S. utilities and planning regions near Puerto Rico were also developed. These are discussed below:

Florida Reliability Coordinating Council

As the closest state to Puerto Rico, Florida shares similarities to Puerto Rico in terms of climate and both solar energy potential and growth. The Florida Reliability Coordinating Council (FRCC) is a southeast U.S. regional entity responsible for assessing and ensuring reliable operation of the bulk power system, as is required by the Florida Public Services Commission. FRCC has several different member organizations, comprised of local utilities, electricity cooperatives, and other similar organizations. FRCC receives data annually from its members to develop a regional load and resource plan to produce an electricity reliability assessment report.[30] This report projects electrical system performance for the FRCC region by analyzing reserve margins, LOLP, forced outage rates, and other related items. One item that is directly applicable to Puerto Rico is FRCC's adequacy calculation, which removes the availability of firm

[29] Guam Power Authority 2022 Integrated Resource Plan.
[30] FRCC 2021 Load & Resource Reliability Assessment Report V1, 29 July 2021.

electricity imports, or in other words, treats the region as an island for resource adequacy calculation purposes. The most recent report notes that the "islanded" system is able to meet a 0.10 days per year planning criteria, with reserve margins meeting or exceeding 20% in each year of the ten-year study.

While FRCC and its members are not islanded, electricity transfer limitations and non-import modeling scenarios are considered within their studies; however, the sheer number of generators and size of the system does inherently reduce resource adequacy vulnerabilities when compared to smaller systems such as Puerto Rico's.

Florida Power & Light

Within the FRCC region, Florida Power & Light conducts its own jurisdictional resource planning analysis in accordance with state policies.[31] While Florida Power & Light also plans for a resource adequacy risk target of 0.10 days/year, the utility also enforces two other resource adequacy criteria:

1. A 20% total reserve margin should exist for the summer and winter
2. At least 10% of the total reserve margin must come from centralized generators

It is important to note that there are many demand-side resources in Florida. The planning criteria above are unique in that they address the desire for diversification in how resource adequacy needs are met within Florida. These planning criteria are examples of how utilities can have unique planning criteria based on the characteristics of the specific location.

Resource Adequacy for U.S. Locations with High Solar Levels (Non-Islands)

There has been significant interest and growth in renewable energy over the recent decades both as renewable energy prices have fallen and as federal, state, and local policies have been enacted to promote the growth of renewable energy. Utilities operating within jurisdictions that enforce such policies are required to consider the contributions and impacts of higher renewable generation levels to electrical system resource adequacy. The state currently with the highest amount of installed solar generation in the U.S. is California.

California Utilities

In California, the prevailing renewable portfolio standard requires 60% of the state's electricity come from carbon-free resources by 2030, with the requirement increasing to 100% by 2045. Puerto Rico is also currently pursuing significant growth in solar generation to meet the island's own renewable portfolio standard of 40% by 2025, 60% by 2040, and 100% by 2050. The state regulating authority establishes resource adequacy obligations for all load serving entities, including investor-owned utilities, within state jurisdiction.[32] The state resource adequacy program contains three distinct requirements:

1. Load serving entities are required to meet a 15% PRM on top of their approved load forecast.
2. Each local area must have sufficient capacity to meet energy needs for a 1-in-10 worst weather scenario and an N-1-1 contingency event (e.g., the loss of the two largest generators).
3. Load serving entities are required to procure "flexible capacity", or capacity that can quickly be dispatched and ramped to full power. Specifically, enough flexible capacity must be procured to meet the largest three-hour ramp in system load (defined on a monthly basis). The reason for this

[31] Florida Power & Light Company, Ten Year Power Plant Site Plan 2023-2032.
[32] California Public Utilities Commission, 2021 Resource Adequacy Report.

resource adequacy requirement stems from the fact that there is a significant amount of intermittent generation (i.e., solar energy) installed in the California. As a result, the California electrical system can sometimes see sharp swings in supplied generation if clouds quickly appear, during sunsets, etc. Examples of flexible capacity include dispatchable resources such as energy storage, fast ramping thermal units (such as engines, combustion turbines, combined cycles), etc.

The California Public Utilities Commission performs detailed analyses to determine the amount a generator's capacity is able to contribute toward resource adequacy requirements, which is also known as a generator's effective load carrying capability (ELCC). The ELCC of a generator is defined by how much system loads can increase when the generator is added into the electrical system, with equivalent performance in terms of system resource adequacy. In California, the ELCC calculation is based on an enforcement of a 0.10 days/year LOLE target[33] .

The ELCC of a generator varies by technology type and the capability of the generator to contribute towards serving load when generation is needed most. For example, if generation were needed to meet a load peak in the evening, a stand-alone solar power plant is likely to have a lower ELCC than a solar power plant paired with an energy storage system, due simply to the fact that the stand-alone solar power plant would not be capable of generating much electricity in the evening (since the sun would have nearly set at this time), while the storage system tied to the other solar power plant likely could generate some electricity in the evening. ELCC will vary from one planning region to another because load characteristics change from region to region; for example, the ELCC values calculated for California's generators would not be directly applicable to values calculated for Puerto Rico.

High-Level Comparison by Location

The following table compares the key resource adequacy considerations for various locations, including the location-specific resource adequacy risk measures that are followed. The column for the "Target Adequacy Risk Measures" are the target amounts of loss of load that each utility / planning entity strives to meet. For example, a value of "1 day per 10 years" means that the utility strives to have a system resource adequacy level such that on average there is only one day where load cannot be fully served every ten years.

[33] Incremental ELCC Study for Mid-Term Reliability Procurement. January 2023 Update.

Table A-2: High-Level Resource Adequacy Comparison by Location

Utility / Planning Entity	Target Risk Measure (LOLE, LOLP, LOLH, or Similar Values)	Notes
Virgin Islands Water and Power Authority	1 day per year in 2020, reducing 1 day per 10 years in 2044	U.S. territory islands neighboring Puerto Rico, similar climate and lack of electricity import ability. Additional N-1-1 planning criterion requires sufficient installed capacity to cover loss of two largest resources. Target LOLE is a recent 2024 goal set forth in the 2019 IRP.[1]
Hawaiian Electric Company	Energy Reserve Margin, based on the following: 1 day per 4.5 years	U.S island with similar load profile, generation, climate, and inability to import electricity as exists in Puerto Rico. HECO bases their resource adequacy criteria on a one day per 4.5 years guideline for assessing resource adequacy. This LOLE target helps to inform the Energy Reserve Margin planning criteria, which is the percentage by which the system capacity must exceed the system load in each hour, considering all generation and load reduction sources, including renewable and storage resources (Hawaii's previous planning criteria did not account for the contributions made by renewable generators).[2]
Guam Power Authority	1 day per 4.5 years	U.S. territory island with similarities to Puerto Rico in terms of climate, and lack of electricity import ability. The Guam Power Authority requires a minimum reserve margin of 60%[3].
Florida Reliability Coordinating Council	1 day per 10 years	Florida has a similar climate to Puerto Rico, and similar probability of hurricane events. Florida's LOLE performance is measured under various system conditions, including zero import availability, and varying solar generation levels. Aggressive solar integration targets 30 million solar panels installed by 2030.[4]
Florida Power & Light	1 day per 10 years	Florida Power & Light is a vertically integrated utility located in the southeast U.S. In addition to the 1 day in 10 years LOLP planning criterion, Florida Power & Light maintains 10% generation-only PRM criterion and a 20% total PRM criterion (including other resources, i.e., demand side-reduction, etc.) for summer and winter seasons.[5]
Southern California Edison	1 day per 10 years 0.02-0.03 days per month	Southern California Edison's Integrated Resource Plan studied a 0.1 days per year LOLE standard and considers the latest renewable and environmental/emissions targets. Results showed a need to increase the PRM to 16% in 2026, 17% in 2030 and 18% in 2035 to maintain the traditional 0.1 days per year LOLE standard.[6]
Arizona Public Services Company	24 hours over 10 years	Arizona Public Services Company is a utility in the Western Electricity Coordinating Council and has a 100% clean energy goal for 2050 that includes carbon-free resources like solar, wind, demand-side management, and nuclear. As part of the 2030 interim clean energy goal, a 45% requirement for renewable generation is required. Results from Arizona Public Services' 2020 IRP Reserve Margin Study indicate a 15% reserve margin is sufficient to meet the company's resource adequacy requirements.[7]
Tucson Electric Power (Arizona)	15% Planning Reserve Margin	Tucson Electric Power is a utility in the desert southwest region with similar solar potential to that of Puerto Rico. The utility follows a 15% planning reserve margin guideline, supported by various probabilistic analyses. The referenced IRP investigates numerous renewable penetration levels and the utility has a carbon reduction target of 80% by 2035 relative to 2005 levels. The IRP investigates the ramping capabilities / needs of generation to support renewable growth in the electrical system.[8]

Utility / Planning Entity	Target Risk Measure (LOLE, LOLP, LOLH, or Similar Values)	Notes
Public Service Company of New Mexico	2 days per 10 years	New Mexico has a strong solar potential and a similar load curve to that of Puerto Rico. The Public Service Company of New Mexico IRP is driven by 100% emissions free goal by 2040. It also lists its goal to transition to the industry standard LOLE of 0.1 days per year.[9]
Puget Sound Energy	LOLP of 5% per year	Puget Sound Energy is required by state law to ensure 80 percent of electric sales are met by non-emitting/renewable resources by 2030, and 100 percent by 2045. Puget Sound Energy uses a resource adequacy model to calculate various resource adequacy risk measures that quantify the risk of not serving load, establish peak load planning standards, and quantify the peak capacity contribution of renewable resources.[10]

Sources

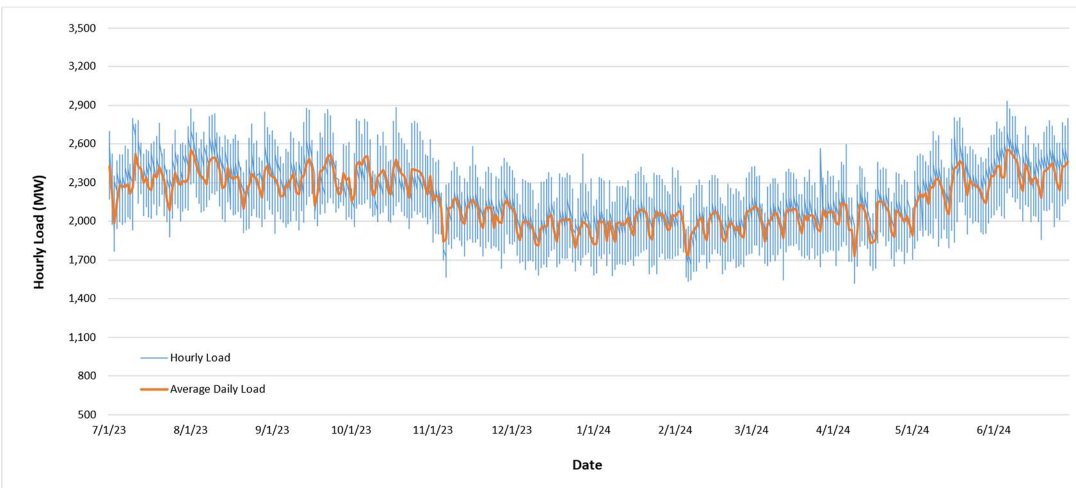
1. VIWAPA Final IRP Report, 21 July 2020.
2. Hawaiian Electric Company Inc., Adequacy of Supply, 29 January 2021.
3. Guam Power Authority 2022 Integrated Resource Plan.
4. FRCC 2022 Summer Load & Resource Reliability Assessment Report May 2022.
5. Florida Power & Light Company, Ten Year Power Plant Site Plan 2023-2032.
6. Southern California Edison Integrated Resource Plan, November 2022.
7. Arizona Public Services Company, 2020 Integrated Resource Plan, 26 June 2020.
8. Tucson Electric Power Company Arizona Public Services Company, 2020 Integrated Resource Plan, 26 June 2020.
9. Public Service of New Mexico 2020 Integrated Resource Plan
10. Puget Sound 2020 Integrated Resource Plan.

Appendix 4. Model Inputs – System Load

A fundamental parameter for resource adequacy modeling is system load. The FY2024 load profile that was used for these studies is shown in the figure below. This load profile was developed based on the actual metered hourly load profile for 2022. Note that approximately 6 weeks of metered load data from the middle of September 2022 through the end of October 2022 was either very low or skewed due to the systemwide impacts of Hurricane Fiona that occurred during this time period. As such, the 2021 historical load data was used to replace the hourly load during this timeframe. In addition, a handful of other hours where data was not available, there were obvious errors in the metered load data values, etc., were corrected.

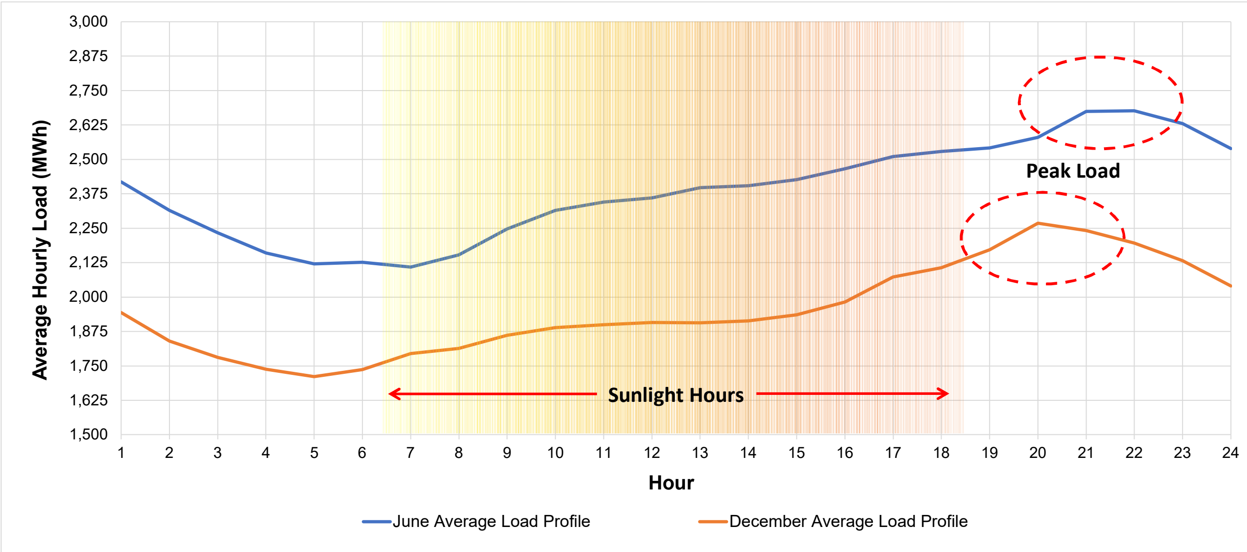
The figure below illustrates the seasonal variations in the annual load profile, with aggregated monthly demand averaging between 1,364 to 1,470 GWh in the winter months, up to near 1,750 GWh in the summer months. The peak demand in 2022 was observed in June and is equal to 2,932 MW. In general load is highest in Puerto Rico during the late summer months.

Figure A-1: Load Profile Used for the FY2024 Resource Adequacy Analysis



Similarly, hourly variations throughout the day are observed in the load profile. The following figure illustrates this variance by presenting hourly load profile, averaged over each day, for the months of June 2022 and December 2022 (the highest and lowest load months, respectively). Electric demand rises in the day with commercial/industrial activity and peaks in the evening, driven by residential activity.

Figure A-2: Resource Adequacy Analysis Load – Hourly Averages



Appendix 5. Model Inputs – Generation Fleet

The characteristics of the Puerto Rican generation fleet (both thermal and renewable generators) are very important inputs into the resource adequacy calculations. Table A-3 shows the thermal generators included in the analysis. The table shows when the power plants began operations, fuel consumed, nameplate capacity, expected available capacity for FY2024, and the expected forced outage rates based on historical operation. The information in the table provides indications of a distressed system with many generators at derated capacity levels and high forced outage rates. Each occurrence of a forced outage was assumed to require a repair time of 40 hours.

Table A-3: Summary of Expected Operating Thermal Generators, FY2024

Generator Name	Start of Operations	Fuel	Nameplate Capacity (MW)	Available Capacity (MW)	Historic Forced Outage Rate (%)
AES 1	2002	Coal	227	227	5
AES 2	2002	Coal	227	227	5
Aguirre Combined Cycle 1[1]	1977	Diesel	296	220	40
Aguirre Combined Cycle 2[1]	1977	Diesel	296	100	30
Aguirre Steam 1[2]	1971	Bunker	450	350	20
Aguirre Steam 2	1971	Bunker	450	330	15
Costa Sur 5	1972	Natural Gas	410	350	12
Costa Sur 6	1973	Natural Gas	410	350	15
EcoElectrica	1999	Natural Gas	535	535	2
Palo Seco 3	1968	Bunker	216	190	12
Palo Seco 4	1968	Bunker	216	190	18
San Juan 7	1965	Bunker	100	70	30
San Juan 9	1968	Bunker	100	90	8
San Juan Combined Cycle 5	2008	Diesel / Natural Gas	220	200	12
San Juan Combined Cycle 6	2008	Diesel / Natural Gas	220	200	12
Cambalache 2	1998	Diesel	82.5	75	10
Cambalache 3	1998	Diesel	82.5	75	10
Mayagüez 1	2009	Diesel	55	50	30
Mayagüez 2	2009	Diesel	55	25	30
Mayagüez 3	2009	Diesel	50	50	30
Mayagüez 4	2009	Diesel	50	50	30
Palo Seco Mobile Pack 1-3	2021	Diesel	27 each (81 total)	81	9
7 Gas Turbines (Peakers)[3]	1972	Diesel	21 each (147 total)	147	40
Total			**4,976**	**4,182**	**—**

Notes:

1. Both Aguirre Combined Cycle 1 and 2 are modeled as two units each (i.e., Aguirre Combined Cycle 1 is modeled as two 110 MW units, each with a forced outage rate 40%) to more accurately capture the fact that a single forced outage to the power plants typically only results in some subset of the power plants being out of service (as opposed to the entire power plant being out of service).
2. The Base Case, which reflects the current system, considers Aguirre 1 to be out of service for the duration of the simulations. This generator is kept out of service in order to account for the planned maintenance schedule overruns that are very common to the main generators on the island. This is described further in Appendix 9.
3. A total of 18 gas turbines, each with a capacity of 21 MW, are installed. Only 7 are considered to be operational due to frequent outages at these units

Table A-4 shows the renewable generators that were included in the analysis, along with their nameplate and available capacities, which for the renewable generators are equal because there are no derates. The existing renewable generators make up approximately 9% of the system's available capacity. Due to the intermittency of renewable generation and their low-capacity factors, forced outages for these generators have been set to zero for the resource adequacy analyses.

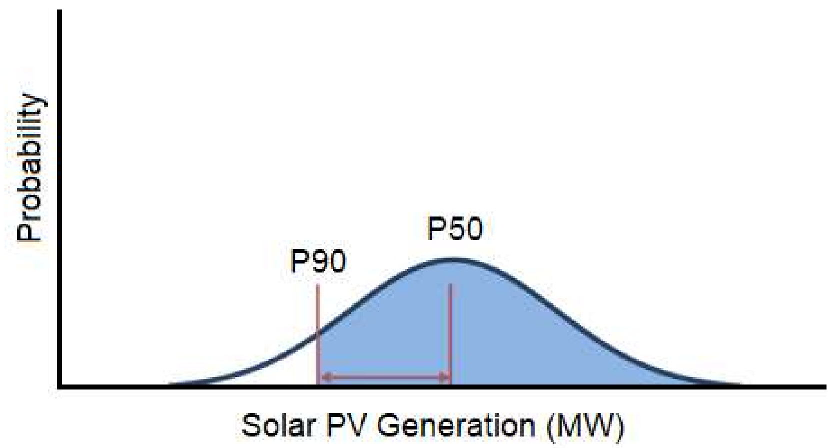
Table A-4: Summary of Operating Renewable Generators

Generator Name	Start of Operations	Fuel	Nameplate / Available Capacity (MW)
AES Ilumina	2012	Sun	20
Fonroche Humacao	2016	Sun	40
Horizon Energy	2016	Sun	10
Yarotek (Oriana)	2016	Sun	45
San Fermin Solar	2015	Sun	20
Windmar (Cantera Martino)	2011	Sun	2.1
Windmar (Vista Alegre / Coto Laurel)	2016	Sun	10
Pattern (Santa Isabel)	2012	Wind	75
Fajardo Landfill Tech	2016	Methane Gas	2.4
Tao Baja Landfill Tech	2016	Methane Gas	2.4
Punta Lima Wind	Aug 2023	Wind	26
Ciro 1 Solar	Dec 2023	Sun	90
Xzerta Solar	June 2024	Sun	60
Total			**402.9**

For power plants with intermittent / variable generation profiles (i.e., the renewable power plants) it is important to determine the amount of hourly dependable capacity that could be used to reliably serve load from a resource adequacy perspective. The methodology used in these analyses shares similarities to the methodology employed by HECO, as described in Section 1.4.3. For this analysis, actual historical generation data (between 2019 and 2022) from each of the currently operating renewable power plants was analyzed. Each generator's 90th percentile production level for each hour was identified and then used as that resource's hourly capacity contribution for the resource adequacy calculations.

For reference, the 90th percentile, or P90, of a resource's electricity production is the amount the resource is statistically likely to generate during that hour for 90% or more of the time. The 50th percentile, or P50, of a resource's generation is the amount the resource is likely to produce during that hour 50% or more of the time – in other words, on average. A resource's P50 generation will be higher than the resource's P90 generation as shown in the illustration below.

Figure A-3: P50 and P90 Probability Densities



For the planned solar PV generators (Punta Lima, Ciro 1, and Xzerta), as well as the planned Tranche 1 solar PV projects, the historical 90th percentile production levels of the combined currently operating renewable generators were used to develop normalized profiles to forecast the expected generation of the planned renewable generators. Note that for future solar PV paired with storage resources, it was assumed that the average, or P50, of the solar PV generation would charge the storage, while the P90 solar PV generation level would still be used as the solar PV capacity contribution towards system resource adequacy.

This overall methodology captured the contributions of the renewable generators to improving system resource adequacy from a statistical framework, accounting for the intermittency of the generators. It was also fundamentally based on the actual historical production levels of the existing renewable generators.

Properly capturing the hourly capacity contributions from variable generators is an important consideration for resource adequacy analyses since the hourly contributions of variable generators are, by definition, uncertain. Overestimating the capacity contribution of variable generators can leave the electrical system with capacity shortfalls in the event the variable generators are unable to generate when they are expected to, while underestimating the capacity contribution of variable generators can make the electrical system appear less reliable than in actuality. As a result, a sensitivity analysis was performed to investigate different variable generator capacity contributions beyond only the 90th percentile historical generation. This sensitivity analysis is described in Appendix 7. The sensitivity analysis results illustrate that the use of less conservative hourly capacity contributions from the variable generators (i.e., 50th percentile instead of 90th percentile of hourly historical generation) modestly improves system LOLE. In addition, an estimate of the ELCC of the solar PV resources was calculated in Appendix 30.

The following table shows the estimated amount of generation that is installed BTM across the different regions of Puerto Rico (as of Q1 2022). BTM generation is broken down between resources connected to the distribution system and resources connected to the transmission system; both of which are primarily composed of rooftop solar. These BTM resources are considered in the analysis as reductions in system load and thus are not modeled explicitly like supply-side generators. Instead, their generation is captured implicitly in the annual load forecast.

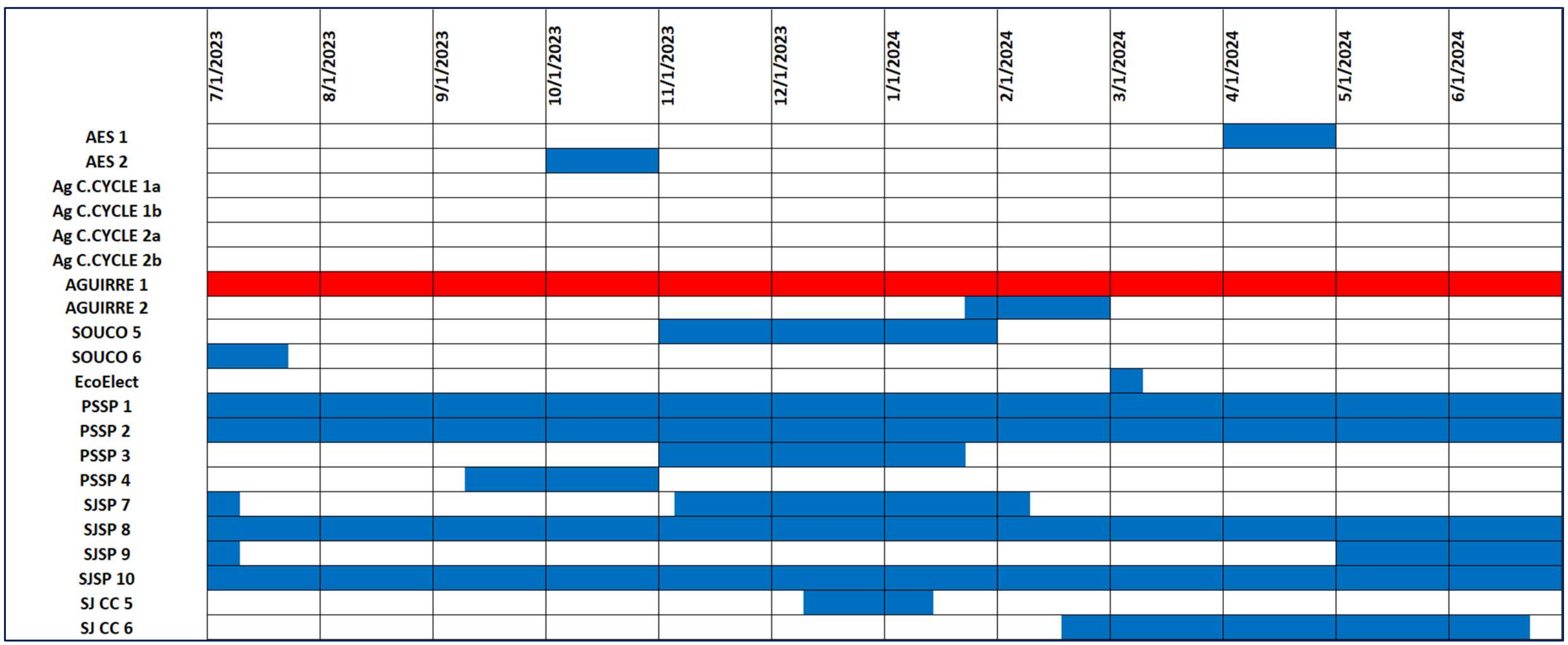
Table A-5: Summary of Behind the Meter Generation by Area

Area	BTM Generation
Caguas	108
Bayamón	119
Ponce	82
Carolina	75
Mayagüez	63
San Juan	79
Arecibo	54
Total	**580**

The following figure shows when the thermal units are expected to be out of operation, either due to planned regular maintenance or because of extended repairs. Any other capacity limitations due to forced outages would be in addition to these planned outages. It should be noted that the planned outage schedule below was modified by LUMA from the most recent version provided by PREPA (dated May 4, 2023). PREPA's schedule had well over 1,000 MW of capacity scheduled for planned maintenance during both the months of October and November 2023, with relatively little capacity scheduled for maintenance in other months. In reality, this large amount of capacity cannot and would not be scheduled to be offline simultaneously – there simply would not be enough remaining power plants to meet system load. As such, LUMA had to modify PREPA's planned outage schedule (for this analysis) to reflect a more reasonable planned outage schedule. The revised schedule keeps the same outage duration as is specified in the PREPA schedule, but staggers the timing of the outages to different months.

Note that Aguirre 1 is kept offline for the duration of the resource adequacy simulations. The reason for this is because the planned outage durations specified by PREPA have historically lasted significantly longer than originally planned – for example, between Jan. 2021 and Feb. 2023, PREPA's planned outage duration averaged 31% longer than planned (see Appendix 9). As such, Aguirre 1 is kept offline to capture the generation capacity deficiency that arises as a result of the planned outage durations typically lasting much longer than scheduled.

Figure A-4: Planned Maintenance Outages for Thermal Units in FY2024

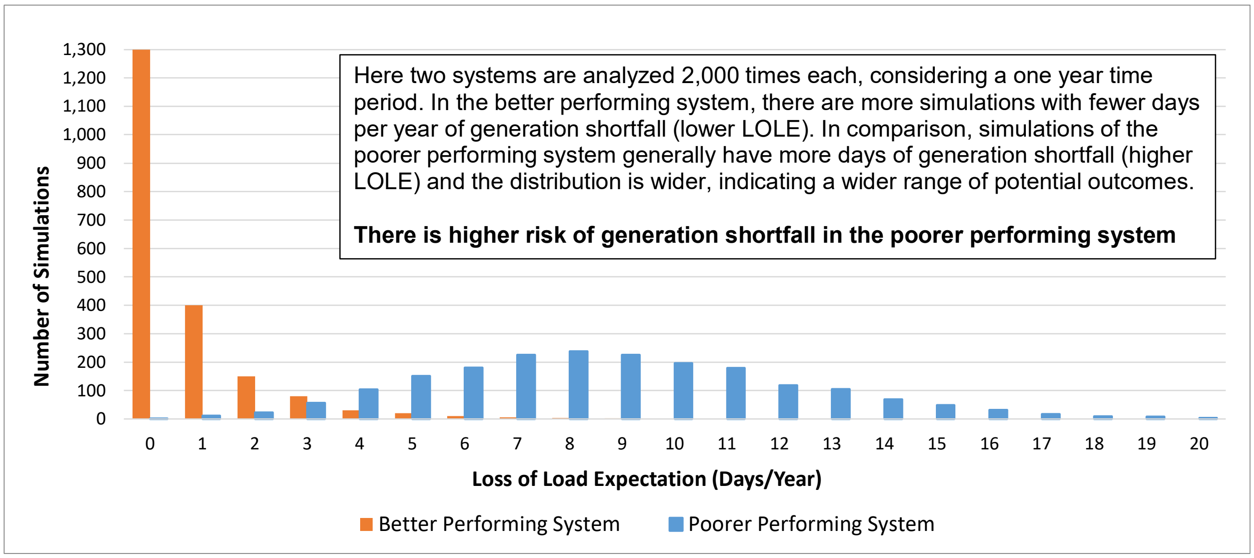


Appendix 6. Resource Adequacy Modeling Introduction

The fundamental calculation at the center of resource adequacy modeling is determining the total amount of generation capacity that is available and comparing it to system load. For each simulated scenario, the total capacity available to serve system load is determined for each hour of the simulated year, then each simulation is re-run many times to account for different forced outage timing. Available capacity is the sum of available thermal, renewable, energy storage capacity (based on the storage charge level) and interruptible load (demand response). The output of the simulations is a statistical distribution of simulation results that help to inform the risk associated with generation shortfall in the future.

An example figure below helps to illustrate sample results of resource adequacy simulations. The figure presents the distribution of LOLE output for two systems that are simulated 2,000 times each. As can be seen, the better performing system has more simulations with lower LOLE than the poorer performing system.

Figure A-5: Example Systems LOLE Distribution Comparison



The key inputs associated with the model are described as follows.

System Load

The load profile was developed based on the actual hourly metered load profile for 2022. Appendix 4 discusses the system load input in detail.

Thermal Generation Inputs

- **Generator available capacity.** The net capacity of the thermal generator (nameplate capacity minus any derates) defines the capacity contribution of the thermal generator when it is available to serve load, i.e., when the generator is not in either a planned or forced outage. The available capacity values used for this analysis are provided in Appendix 5.
- **Generator planned outage schedule.** This input defines when the thermal generator is expected to be out on a planned maintenance outage. The planned outage schedule used for this analysis is discussed in Appendix 5.
- **Generator forced outage rate.** The forced outage rate is based on historical forced rates of the thermal generators dating back 5 years. The forced outage rate defines how frequently a power plant breaks down during the simulation. The timing of forced outage events is random in the simulation. The forced outage rates used for this analysis are provided in Appendix 5.
- **Generator forced outage duration.** This input defines how long it takes a thermal power plant to come back online after a forced outage. For this analysis the forced outage duration is set to 40 hours.

Renewable Generation Inputs and Methodology

- **Historical Hourly Renewable Generation.** The simulated generation associated with the existing renewable power plants is based on historical operating data from the power plants. From a resource adequacy perspective, it was important to determine the amount of renewable generation that could reliably be counted on as available to serve load. The methodology used in this analysis to determine the reliable contribution of the renewable power plants shares many similarities to the methodology employed by HECO. For this analysis, each power plant's historical 90th percentile lowest production level for each hour was identified. These profiles were used in the analysis.
- **Forecasted Hourly Renewable Generation Production.** For future renewable generators, forecasted hourly generation is computed based on the historical output of the existing renewable resources in Puerto Rico. The hourly profile of the forecasted renewable generation is determined using normalized profiles developed from the historical renewable generation. All forecasted hourly profiles are adjusted to a P90 probabilistic level for each hour of generation prior to performing the simulations. A P90 level is used as this was assumed to be the production level that could reliably be counted on to serve system load from a resource adequacy perspective.

Properly capturing the hourly capacity contributions from variable generators is an important consideration for resource adequacy analyses since the hourly contributions of variable generators are, by definition, uncertain. Overestimating the capacity contribution of variable generators can leave the electrical system with capacity shortfalls in the event the variable generators are unable to generate when they are expected to, while underestimating the capacity contribution of variable generators can make the electrical system appear less reliable than in actuality. As a result, a sensitivity analysis was performed to investigate different variable generator capacity contributions beyond only the 90th percentile historical generation. This sensitivity analysis is described in Appendix 7. The sensitivity analysis results illustrate that the use of less conservative hourly capacity contributions from the variable generators (i.e., 50th percentile instead of 90th percentile of hourly historical generation) modestly improves system LOLE.

Energy Storage Inputs

Energy storage is considered in the model in two forms: standalone energy storage and solar-paired energy storage. For both types of storage, the normal (non-emergency) discharge time is set to start in the evening, coinciding with peak load. The energy storage is modeled to inject all of its stored energy to meet peak load through evening. In the event that an emergency event occurs, defined as a time when load exceeds available capacity, the energy storage resources are modeled such that they inject stored energy up to their nameplate capacity to either meet the system generation shortfall, or if the generation shortfall is too great, minimize the magnitude of the shortfall. Once the amount of stored energy is depleted, the modeled energy storage is unable to inject additional energy. During an emergency event, the energy storage is modeled to inject its storage energy regardless of the time of day or how much energy is stored at that time. All storage is modeled as having an 85% round-trip efficiency. Specific details regarding standalone and solar-paired energy storage are provided below.

- **Standalone Energy Storage.** Standalone energy storage resources are modeled as being able to charge via the grid, with the freedom to charge from any type of generation resource. These resources are modeled such that charging is allowed to start in the early morning (i.e., around midnight), so long as there is excess generation capacity available during that time.
- **Energy Storage Paired with Solar PV.** These storage resources are modeled similarly to standalone energy storage, with the caveat that solar-paired storage can only charge from available solar PV generation. As such, storage paired to solar PV begins charging around 9 a.m. and is able to continue to charge through the day until sunset. The full expected average hourly solar PV production is assumed to be available to charge the battery. As explained above, the lower P90 probabilistic level is used to count the hourly solar capacity contribution.

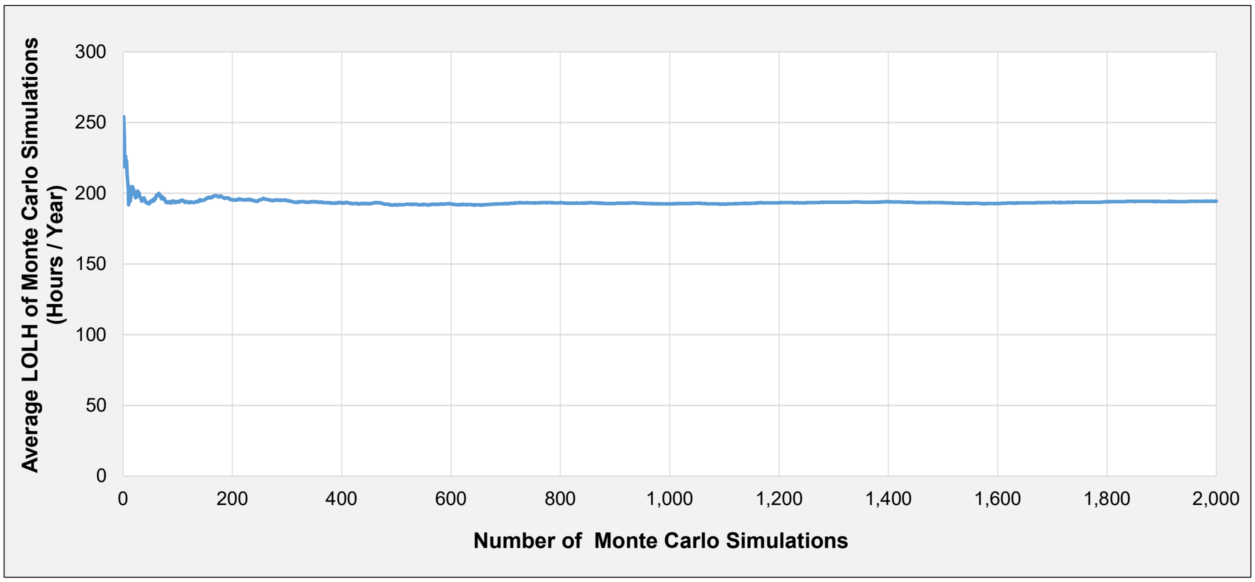
Note that the charging and discharge profiles (i.e., the specific charging / discharging hours) specified in the model for both the standalone and solar-pared energy storage systems were validated using a detailed hourly dispatch simulation in the PLEXOS production cost modeling software.

Appendix 7. Resource Adequacy Model Convergence and Validation

Model Convergence

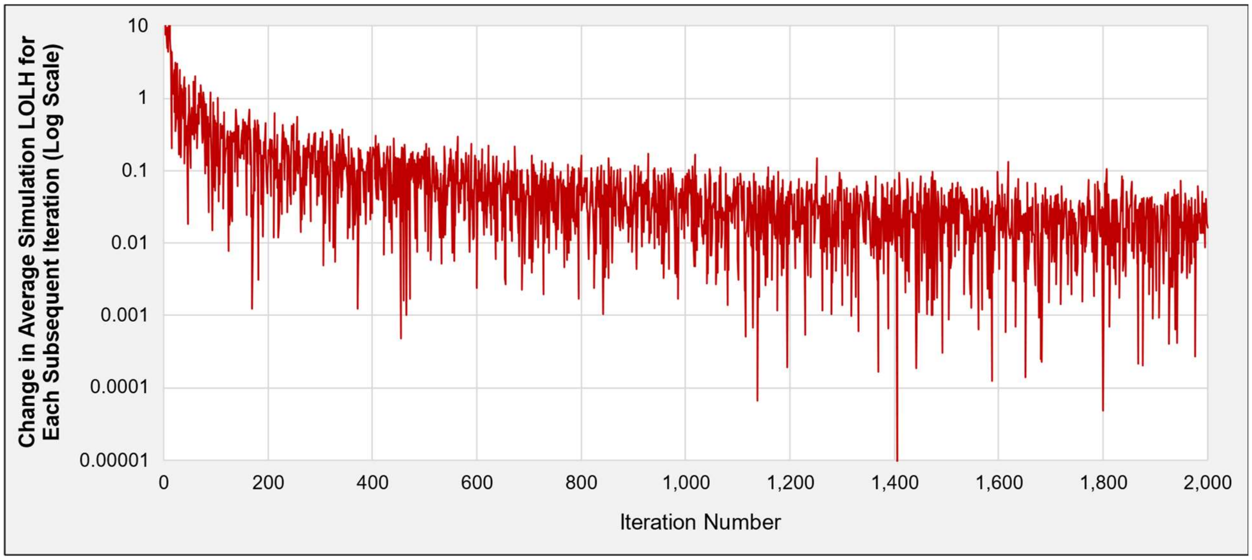
The following figures help to illustrate the convergence of the PRAS model calculation process. In the first figure, the x-axis represents the number of simulations performed, and the y-axis represents the average number of LOLH calculated based on the number of simulations performed. For example, the figure indicates that the average LOLH at 500 simulations was approximately 195 LOLH, meaning the average number of annual LOLH for simulation numbers 1 through 500 was approximately 195 LOLH. As can be seen in the plot, the solution starts to converge relatively quickly in the calculation process.

Figure A-6: Average Simulation LOLH per Subsequent Iterations



The following figure illustrates the average LOLH for all completed simulations as a function of each subsequent iteration. Results are presented on a logarithmic scale y-axis. As can be seen in the plot, the change in average LOLH falls below 0.1 LOLH approximately 500 iterations into the simulation. At that point, results were considered to be generally converged; however, an additional 1,500 simulations were completed to further validate convergence. All results from the PRAS model presented in this report performed 2,000 iterations.

Figure A-7: Change in Simulation LOLH per Subsequent Iterations (Log Scale)



Model Forced Outage Duration

As part of the overall validation process, a sensitivity analysis was performed to determine the impact of modeled generator forced outage duration on LOLE and LOLH model output. Five different forced outage durations were considered (keeping individual generator forced outage rates constant across all scenarios): 20 hours, 40 hours, 60 hours, 80 hours, and 100 hours. Note that for each scenario, the modeled outage duration was applied for all generators, i.e., for the 100-hour forced outage duration scenario, a forced outage for each of the generators was assumed to last 100 hours.

The results of this sensitivity analysis are documented in Appendix 9 of LUMA's *FY2023 Puerto Rico Electrical System Resource Adequacy Analysis* report. The results showed that as forced outage durations increase, there was a slight decrease in LOLE but no discernable difference in LOLH – illustrating that when modeling forced outages, the forced outage rates (which are based on historical generator performance and are a good indication of expected generator availability), rather than the forced outage durations, are the more critical metric for the purposes of these resource adequacy evaluations.

Capacity Contribution Modeling Sensitivity – Variable Production Resources

Properly capturing the hourly capacity contributions from variable generators is an important consideration for resource adequacy analyses since the hourly contributions of variable generators are, by definition, uncertain. Overestimating the capacity contribution of variable generators can leave the electrical system with capacity shortfalls in the event the variable generators are unable to generate when they are expected to, while underestimating the capacity contribution of variable generators can make the electrical system appear less reliable than in actuality.

A sensitivity analysis using the less conservative 50th percentile (P50) of historical generation was performed to investigate the impact of different variable generator capacity contributions beyond only the 90th percentile historical generation on resource adequacy. The results illustrate that the use of less conservative P50 hourly capacity contribution from the variable generators modestly improves system LOLE. The results are shown in the following table.

Table A-6: Calculated LOLE – P50 and P90 Renewable Generation

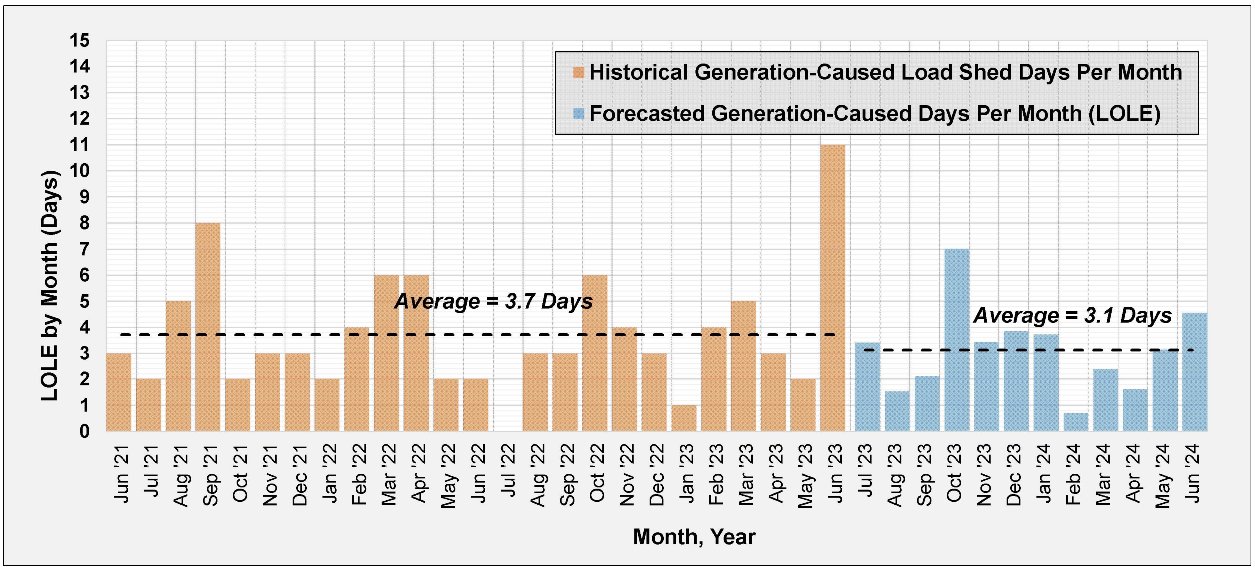
Scenario	Loss of Load Expectation (LOLE)
Current System (Base Case) – **P90** Renewable Generation	37.5
Current System (Base Case) – **P50** Renewable Generation	35.0
Industry Benchmark Target	0.1 Days / Year

It is important to note that a P50 generation level is much less conservative than a P90 level, and by definition, can only be relied upon 50% of the time – meaning that half of the time, generation from the resource will be lower than the P50 level. Because of this, use of a P50 threshold in resource adequacy modeling could lead to results that portray a much more optimistic picture of the electrical system than reality.

Model Comparison to Historical Load Shed Data and Validation

One key validation method is to compare the current resource adequacy results to past system performance. The following figure compares the historic number of generation-caused load shed days per month (i.e., due to generation shortfalls) to the monthly LOLE forecast for FY2024. As can be observed in the figure, there is a strong agreement between the historical data and forecasted results. Both in the forecast for FY2024 and in the recent historical data, the average number of days of generation-caused load shed hovers just above 3 days per month. The agreement between the historical data and the model results indicates the PRAS model output is a reasonable estimate of future system resource adequacy performance.

Figure A-8: Comparison of Monthly Historical and Forecasted Generation-Caused Load Shed



Note: The above plot compares load shed that occurs over the course of "normal" system operation. Load shed for September 2022 after September 18th are not included in the above plot. This is because load shed for this month was primarily driven by the damage caused by Hurricane Fiona, which was an event that was beyond what is considered to be the "normal" operation of the system. The large number of days of load shed in June 2023 were driven primarily by a combination of very high temperatures (and thus high electrical demand) and generator outages.

Model Validation Using Third Party Simulations

Resource adequacy analyses of the Puerto Rican electric system were performed using the PRAS model, a probabilistic resource adequacy simulation tool adapted for the Puerto Rican electrical system. As part of the PRAS model validation, a thorough benchmarking / error checking process was undertaken to verify simulation output using other 3rd party production cost and dispatch simulation tools. This validation is documented in Appendix 7 of LUMA's *FY2023 Puerto Rico Electrical System Resource Adequacy Analysis* report. The validation process illustrated strong agreement between the PRAS model and other 3rd party production cost and dispatch simulation tools.

Appendix 8. Forced Outage Rates – PREPA Units

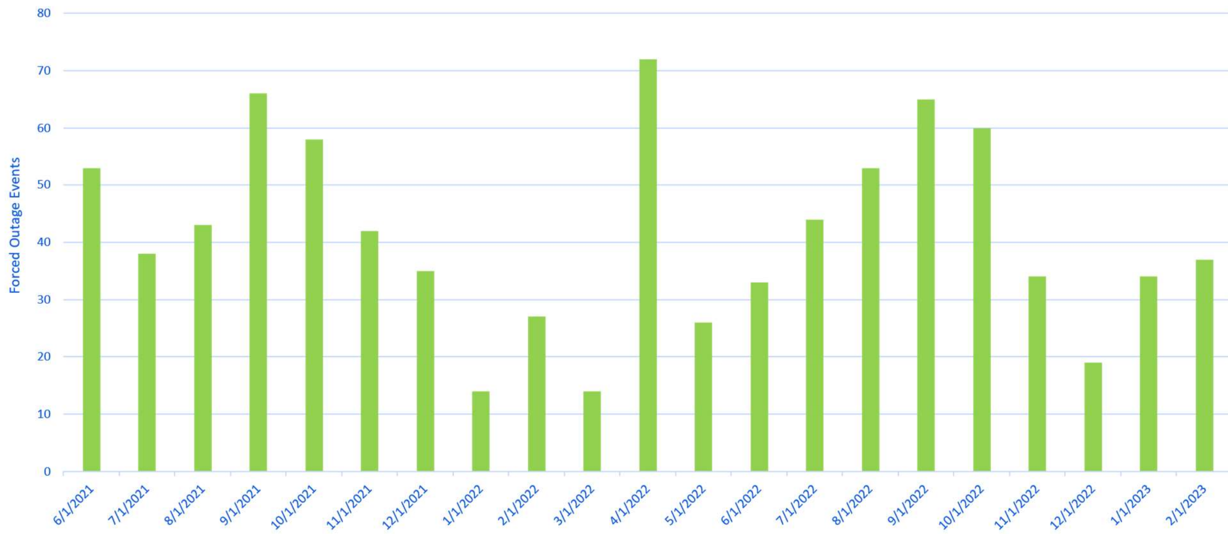
From a resource adequacy perspective, the generation portfolio in Puerto Rico raises several challenges. While the AES and EcoElectrica power plants exhibit very strong performance on forced outage rates with annual rates of approximately 5% and 2%, respectively (which are consistent or slightly better than industry averages for comparable units), the PREPA generation plants have, for various reasons, historical forced outage rates of approximately 18% for baseload and 29% for peaker plants (which is significantly higher than industry averages)[34]. For reference, the average equivalent forced outage rate for North American power plants over the past five years was 7.25%.[35]

The Puerto Rico generation portfolio is dominated by its relatively high concentration of larger units. There are five units that are over 400 MW nameplate capacity, and another eight that are over 200 MW capacity. If one of the larger units has a forced outage, the grid loses approximately 10% of its operating capacity at any given time. This is a significantly large amount of generation capacity to lose from a portfolio risk perspective. In most ISOs in North America, a loss of even a large 1,000 MW nuclear plant has minimal impact to the entire grid because that represents only one or two percent of total operating capacity. In addition, being an island with no interconnecting transmission lines to neighboring utilities, the resource adequacy analysis is much more sensitive to the selection of the appropriate forced outage rate than would be seen in most utilities in the mainland and around the world.

Most utilities plan for an N-1 planning standard so that if one significant event occurs (e.g., loss of generator or major transmission line), service to customers is not interrupted. These types of events are not significant in the mainland since there is always a high likelihood that neighboring capacity that can be acquired at some price. In Puerto Rico, the modeling assumptions must acknowledge that first there is a higher probability of losing a major unit and thus 10% of generating capacity, and secondly, losing that first unit also increases the probability of causing the loss of a second unit due to the additional stresses put on the remaining power plants due to low reserve margins.[36] This is illustrated in Figure A-9, which shows that the forced outage rate during summer months when reserves are low is almost twice the forced outage rate of the rest of the year.

[34] Weighted average by capacity
[35] North American Electric Reliability Corporation, 2022 State of Reliability: An Assessment of 2021 Bulk Power System Performance, July 2022, page 37.
[36] For modeling purposes in this analysis, a forced outage event to a generator is treated as an independent event, unrelated to other forced outages on the system. Future iterations of this analysis might consider whether correlations between forced outages might be incorporated.

Figure A-9: Total Forced Outage Events, All PREPA Units – June 2021–February 2023



To apply the appropriate forced outage rates for this resource adequacy analysis, LUMA considered the historical forced outage rates over the past nine years, but primarily focused on the most recent data since June 2019. LUMA evaluated each unit and considered the average forced outage rates for the most recent six months, year, and past four years to determine the appropriate rate by generator. In some cases, poor performance was not weighted as heavily if it occurred two or three years ago and demonstrated improvement since then. LUMA considered the forced outage rate for each plant and identified a revised forced outage rate for each unit. The forced outage rates assumed for resource adequacy modeling are summarized in the table below and the supporting analysis for each unit in the PREPA portfolio is discussed in the pages that follow in this appendix.

Table A-7: Summary of Expected Operating Thermal Generators in FY2024

Generator Name	Start of Operations	Fuel	Nameplate Capacity (MW)	Available Capacity (MW)	Modeled Forced Outage Rate (%)
AES 1	2002	Coal	227	227	5
AES 2	2002	Coal	227	227	5
Aguirre Combined Cycle 1[1]	1977	Diesel	296	220	40
Aguirre Combined Cycle 2[1]	1977	Diesel	296	100	30
Aguirre Steam 1[2]	1971	Bunker	450	350	20
Aguirre Steam 2	1971	Bunker	450	330	15
Costa Sur 5	1972	Natural Gas	410	350	12
Costa Sur 6	1973	Natural Gas	410	350	15
EcoElectrica	1999	Natural Gas	535	535	2
Palo Seco 3	1968	Bunker	216	190	12
Palo Seco 4	1968	Bunker	216	190	18

Generator Name	Start of Operations	Fuel	Nameplate Capacity (MW)	Available Capacity (MW)	Modeled Forced Outage Rate (%)
San Juan 7	1965	Bunker	100	70	30
San Juan 9	1968	Bunker	100	90	8
San Juan Combined Cycle 5	2008	Diesel / Natural Gas	220	200	12
San Juan Combined Cycle 6	2008	Diesel / Natural Gas	220	200	12
Cambalache 2	1998	Diesel	82.5	75	10
Cambalache 3	1998	Diesel	82.5	75	10
Mayagüez 1	2009	Diesel	55	50	30
Mayagüez 2	2009	Diesel	55	25	30
Mayagüez 3	2009	Diesel	50	50	30
Mayagüez 4	2009	Diesel	50	50	30
Palo Seco Mobile Pack 1-3	2021	Diesel	27 each (81 total)	81	9
7 Gas Turbines (Peakers)[3]	1972	Diesel	21 each (147 total)	147	40
Total			**4,976**	**4,182**	**—**

Notes:

1. Both Aguirre Combined Cycle 1 and 2 are modeled as two units each (i.e., Aguirre Combined Cycle 1 is modeled as two 110 MW units, each with a forced outage rate 40%) to more accurately capture the fact that a single forced outage to the power plants typically only results in some subset of the power plants being out of service (as opposed to the entire power plant being out of service).
2. The Base Case, which reflects the current system, considers Aguirre 1 to be out of service for the duration of the simulations. This generator is kept out of service in order to account for the planned maintenance schedule overruns that are very common to the main generators on the island. This is described further in Appendix 5 and Appendix 9.
3. A total of 18 gas turbines, each with a capacity of 21 MW, are installed. Only 7 are considered to be operational due to frequent outages at these units

The following table provides the historical annual forced outage rates for the various thermal generators in Puerto Rico since 2013.

Table A-8: Historic Forced Outage Rates for PREPA Fleet Thermal Generators

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
CT 5 (SJ 5)	15%	2%	2%	16%	98%	7%	10%	4%	6%	5%
STG 5 (SJ 5)	13%	2%	3%	6%	8%	8%	44%	8%	4%	30%
CT 6 (SJ 6)	1%	51%	30%	5%	5%	2%	7%	6%	2%	2%
STG 6 (SJ 6)	5%	17%	28%	7%	6%	3%	8%	60%	20%	76%
SJ 7	7%	7%	5%	11%	7%	12%	49%	52%	12%	13%
SJ 8	3%	5%	3%	13%	12%	28%	0%	73%	59%	99%
SJ 9	3%	6%	2%	9%	19%	48%	8%	9%	4%	7%
SJ 10	8%	49%	97%	100%	100%	100%	100%	100%	100%	100%
PS 1	8%	15%	7%	3%	4%	14%	18%	47%	76%	100%
PS 2	2%	1%	6%	13%	100%	100%	100%	100%	100%	100%
PS 3	15%	0%	6%	10%	61%	15%	10%	6%	14%	6%
PS 4	3%	2%	93%	100%	100%	100%	68%	9%	15%	25%
CS 5	0%	2%	1%	0%	0%	5%	10%	59%	7%	13%
CS 6	4%	0%	2%	12%	12%	1%	2%	98%	45%	4%
AG 1	2%	6%	27%	7%	7%	6%	1%	5%	4%	42%
AG 2	3%	2%	11%	100%	15%	3%	77%	27%	17%	20%
AG CC 1	20%	9%	6%	14%	47%	54%	17%	35%	42%	51%
AG CC 2	3%	10%	37%	63%	39%	50%	5%	3%	79%	78%

Figure A-10: Average Forced Outage Rate – January 2022 to December 2022

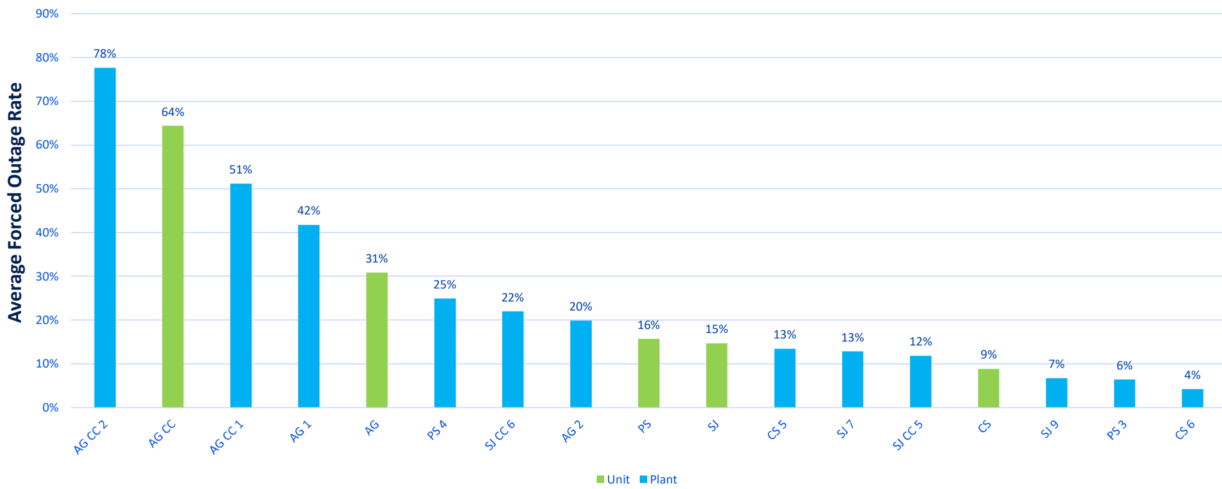


Figure A-11: Average Forced Outage Duration – June 2021 to February 2023

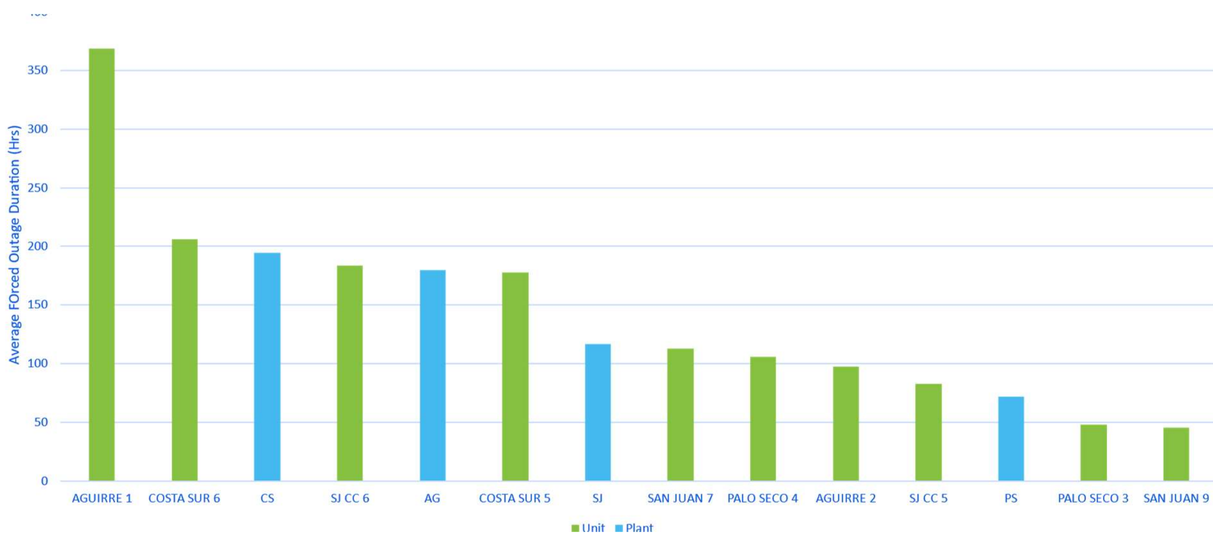
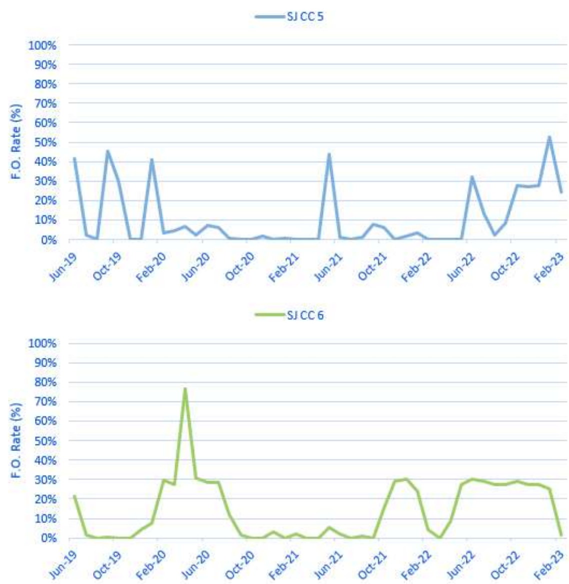


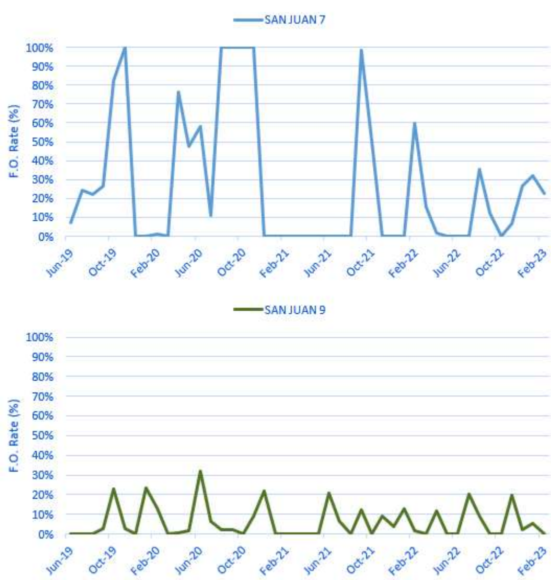
Figure A-12: San Juan 5 and 6 Forced Outage Data



- Post Fiona Input is the Escalated Forced Outage Rate from the RA Inputs Document
- Post Fiona AVG is calculated using data from 9/22 - 2/23

	45 Month AVG	2022 PROMOD Input	Post Fiona Input	Post Fiona AVG	New 2023 Input
SJ CC 5	10.54	7	7.7	28.19	10
SJ CC 6	14.33	7	7.35	23.19	10

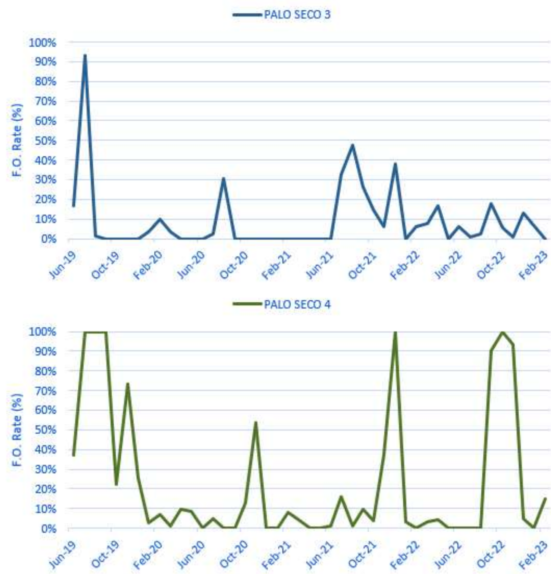
Figure A-13: San Juan 7–10 Forced Outage Data



- Post Fiona Input is the Escalated Forced Outage Rate from the RA Inputs Document
- Post Fiona AVG is calculated using data from 9/22 - 2/23

	45 Month AVG	2022 PROMOD Input	Post Fiona Input	Post Fiona AVG	New 2023 Input
SJ 7	27.09	30	31.5	16.78	30
SJ 8	58.41	30	31.5	-	-
SJ 9	6.21	10	10.5	4.67	8
SJ 10	100.00	20	21	-	-

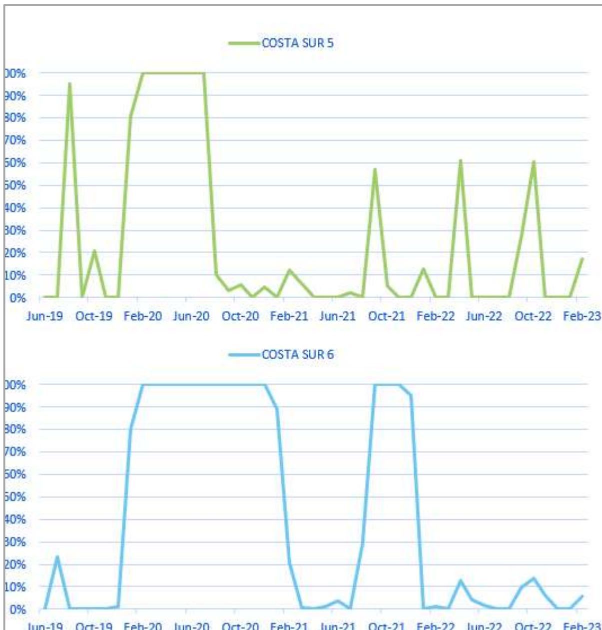
Figure A-14: Palo Seco Forced Outage Data



- Post Fiona Input is the Escalated Forced Outage Rate from the RA Inputs Document
- Post Fiona AVG is calculated using data from 9/22 - 2/23

	45 Month AVG	2022 PROMOD Input	Post Fiona Input	Post Fiona AVG	New 2023 Input
PS 1	63.21	20	21	-	-
PS 2	100.00	20	21	-	-
PS 3	9.13	15	15.75	7.46	12
PS 4	23.45	15	15.75	50.77	18

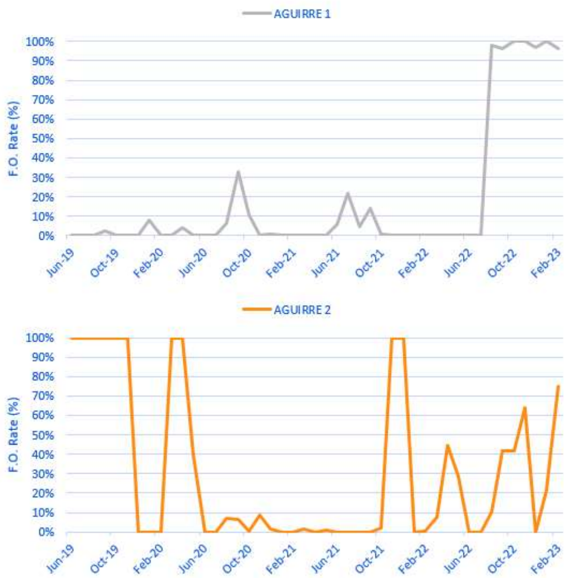
Figure A-15: Costa Sur 5 & 6 Forced Outage Data



- Post Fiona Input is the Escalated Forced Outage Rate from the RA Inputs Document
- Post Fiona AVG is calculated using data from 9/22 - 2/23

	45 Month AVG	2022 PROMOD Input	Post Fiona Input	Post Fiona AVG	New 2023 Input
CS 5	24.02	10	11	17.58	10
CS 6	40.02	15	16.5	5.91	15

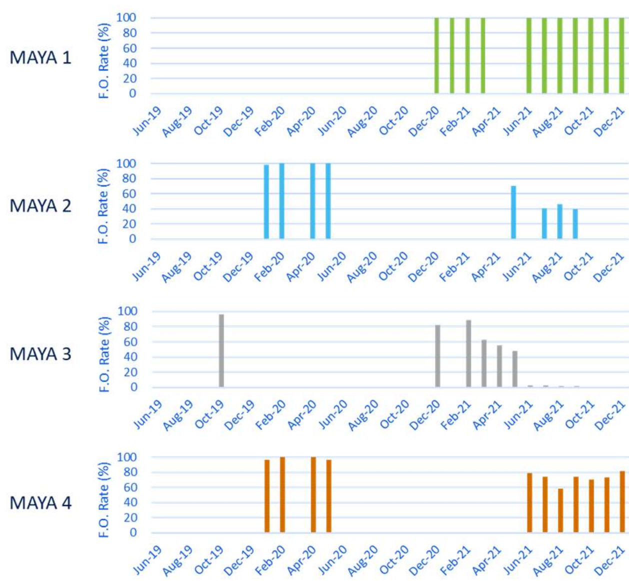
Figure A-16: Aguirre 1 and 2 Forced Outage Data



- Post Fiona Input is the Escalated Forced Outage Rate from the RA Inputs Document
- Post Fiona AVG is calculated using data from 9/22 - 2/23

	45 Month AVG	2022 PROMOD Input	Post Fiona Input	Post Fiona AVG	New 2023 Input
AG 1	17.79	10	11	100.00	10
AG 2	31.17	10	11	39.92	15

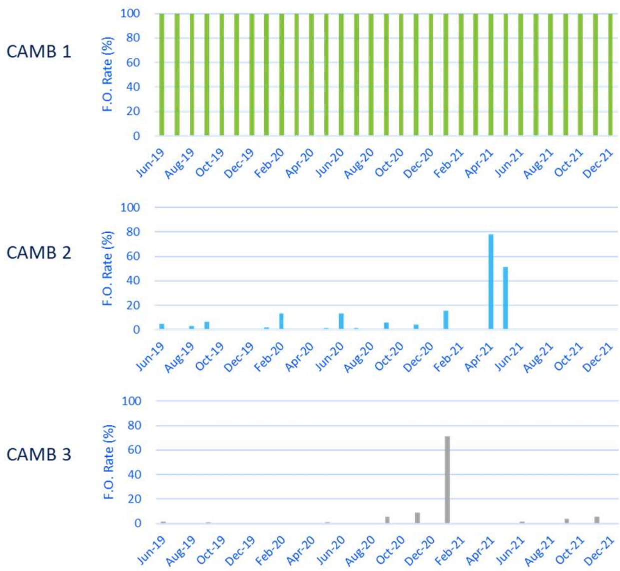
Figure A-17: Mayagüez Forced Outage Data



- MAYA 2 and MAYA 3 suggested inputs based on rolling 31-month average FOR
- Maya 1 and MAYA 4 suggested input based on rolling 6-month average FOR

	31 Month AVG	2020 PROMOD Input	2021 AVG	New Suggested Input
MAYA 1	35.48	8.47	83.33	100
MAYA 2	19.20	28.14	16.42	19.2
MAYA 3	14.23	4.23	21.88	14.23
MAYA 4	29.09	28.52	42.4	71.68

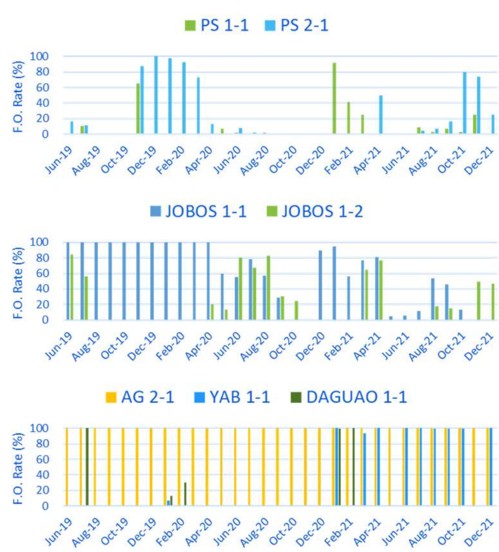
Figure A-18: Cambalache Forced Outage Data



- CAMB 2 and CAMB 3 suggested inputs based on rolling 31-month average FOR
- CAMB 1 is out of service

	31 Month AVG	2020 PROMOD Input	2021 AVG	New Suggested Input
CAMB 1	100	100	100	-
CAMB 2	6.50	1	12.17	6.5
CAMB 3	3.26	0	6.83	3.26

Figure A-19: Gas Turbine Peakers Forced Outage Data



- Peakers are all given 20% FOR based on multiple factors and due to the sporadic use of these units

	31 Month AVG	2020 PROMOD Input	2021 AVG	New Suggested Input
PS 1-1	9.39	20	17.00	40
PS 2-1	24.54	20	21.40	40
JOBOS 1-1	61.70	20	37.00	40
JOBOS 1-2	23.54	20	22.54	40
AG 2-1	100	20	100	40
YAB 1-1	29.03	20	74.43	40
DAGUAO 1-1	11.02	20	16.61	40

Figure A-20: Aguirre CC1 Forced Outage Data

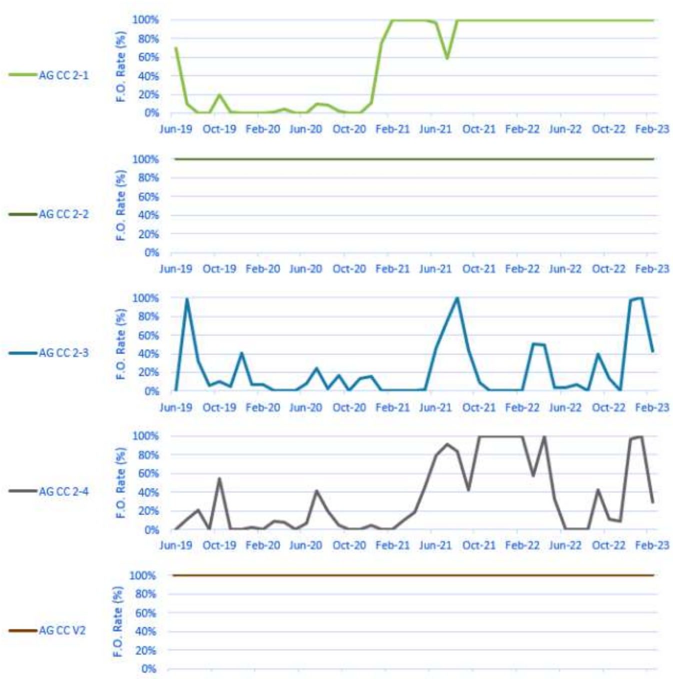
- Post Fiona Input is the Escalated Forced Outage Rate from the RA Inputs Document
- Post Fiona AVG is calculated using data from 9/22 - 2/23

	45 Month AVG	2022 PROMOD Input	Post Fiona Input	Post Fiona AVG
AG CC 1-1	23.57	-	-	100.00
AG CC 1-2	16.82	-	-	53.41
AG CC 1-3	43.67	-	-	100.00
AG CC 1-4	46.92	-	-	70.82
AG CC V-1	61.70	40	42	66.12

Figure A-21: Aguirre CC2 Forced Outage Data

- Post Fiona Input is the Escalated Forced Outage Rate from the RA Inputs Document
- Post Fiona AVG is calculated using data from 9/22 - 2/23

	45 Month AVG	2022 PROMOD Input	Post Fiona Input	Post Fiona AVG
AG CC 2-1	59.28	-	-	100.00
AG CC 2-2	100.00	-	-	100.00
AG CC 2-3	21.60	-	-	49.36
AG CC 2-4	34.01	-	-	48.56
AG CC V-2	100.00	30	31.5	100.00



Appendix 9. Planned Outage Rates – PREPA Units

The planned outage rate is another key factor that affects the modeled availability and reserves throughout the year. PREPA plants have historically exceeded their planned outage durations by a significant amount. Most utilities tightly manage their outage schedules and outage performance and pre-plan their outages two or more years in advance. Outage schedules are tightly monitored and delays of even a few days are uncommon since the parts have been pre-ordered or are on-site, and labor resources are identified. In this environment, planed outage rate performance against schedule is taken as a reliable input.

PREPA has historically exceeded outage schedule durations by approximately 31% during the time period from January 2021 to February 2023. This is significantly higher than industry averages. The following table compiles the forecasted versus planned outage durations between January 2021 and February 2023.

Table A-9: Historical Forecasted Versus Planned Outage Durations

Generator Name	Forecasted Planned Outage Hours	Actual Planned Outage Hours	Variance
Aguirre Steam 1	3,840	5,423	+41%
Aguirre Steam 2	2,832	3,933	+39%
Costa Sur 5	1,680	1,139	-32%
Costa Sur 6	360	251	-30%
Palo Seco 3	1,152	4,400	+282%
Palo Seco 4	2,256	2,241	-1%
San Juan 7	1,296	6,628	+411%
San Juan Combined Cycle 5	3,816	7,904	+107%
Total PREPA Units	**17,232**	**31,919**	**+85%**
Total PREPA Units, Excluding Various Outlier Outage Events (to SJ7, PS3, and SJ9 in 2021)	**13,728**	**17,977**	**+31%**

The reliability of the planned outage assumptions significantly affects the resource adequacy model results. The inaccuracy of the planned outage durations means that power plants on outages will likely not return to operation when they are scheduled to do so. As is discussed in Appendix 5, the planned outage schedule used for this analysis was modified by LUMA from the most recent version provided by PREPA (dated May 4, 2023). PREPA's schedule had well over 1,000 MW of capacity scheduled for planned maintenance during both the months of October and November 2023, with relatively little capacity scheduled for maintenance in other months. In reality, this large amount of capacity cannot and would not be scheduled to be offline simultaneously – there simply would not be enough remaining power plants to meet system load. As such, LUMA had to modify PREPA's planned outage schedule (for this analysis) to reflect a more reasonable planned outage schedule. The revised schedule keeps the same outage duration as is specified in the PREPA schedule, but staggers the timing of the outages to different months. To capture the generation capacity deficiency that arises as a result of the planned outage durations typically lasting much longer than specified in PREPA's planned outage schedule, this analysis keeps Aguirre 1 offline for the entire analysis.

The following figure and table describe the historic planned outages against what was originally scheduled for each of the PREPA units. We evaluated planned outage performance in aggregate and for each individual unit.

Figure A-22: Average Planned Outage Rate by Plant and Unit – January 2022–February 2023

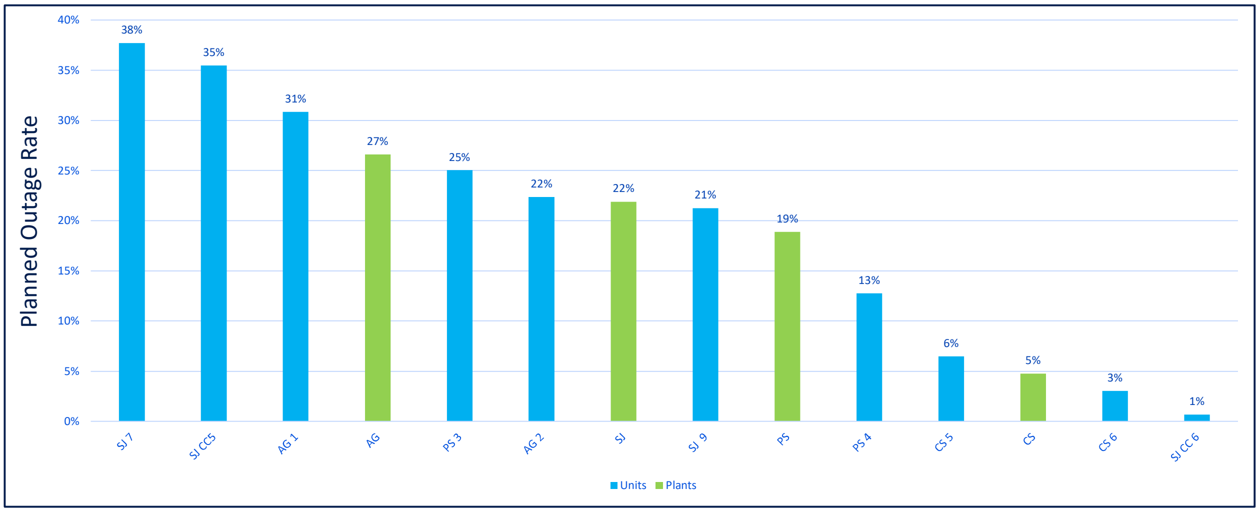


Table A-10: Annual Planned Outage Rate from 2013 to 2022

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Total Avg
SJ 5	4%	51%	4%	2%	8%	10%	24%	11%	24%	46%	**18%**
SJ ST 5	0%	51%	4%	2%	9%	10%	17%	27%	28%	46%	**19%**
SJ 6	12%	17%	50%	16%	0%	12%	8%	22%	1%	8%	**15%**
SJ ST 6	15%	18%	50%	18%	0%	12%	9%	9%	2%	0%	**13%**
SJ 7	22%	13%	12%	18%	32%	71%	39%	14%	67%	9%	**30%**
SJ 8	35%	0%	22%	0%	69%	0%	46%	0%	0%	0%	**19%**
SJ 9	0%	18%	0%	20%	0%	35%	70%	3%	43%	0%	**19%**
SJ 10	0%	44%	0%	0%	0%	0%	0%	0%	0%	0%	**5%**
PS 1	0%	14%	14%	1%	33%	32%	44%	7%	0%	0%	**16%**
PS 2	14%	0%	15%	16%	33%	59%	0%	0%	0%	0%	**15%**
PS 3	68%	100%	75%	0%	37%	0%	0%	28%	50%	1%	**36%**
PS 4	0%	47%	0%	0%	0%	17%	39%	5%	9%	16%	**13%**
CS 5	51%	13%	9%	0%	26%	10%	0%	0%	12%	1%	**12%**
CS 6	0%	16%	10%	3%	0%	20%	0%	0%	3%	3%	**5%**
AG 1	13%	35%	4%	0%	20%	0%	11%	0%	14%	47%	**14%**
AG 2	13%	0%	12%	0%	0%	16%	8%	16%	29%	5%	**10%**

Appendix 10. Maximum Effective Capacity – Baseload Units

To calculate the maximum effective capacity for each unit, LUMA reviewed the past three years of generation data for each unit. LUMA calculated the 95th percentile of hourly generation production that each unit achieved for each of the past three years. In other words, the maximum generation output that each unit was capable of producing for at least 95% of the hours in the year was determined, even if this was not consecutive hourly production. The rationale for this is that for baseload units, System Operations would typically request the units to produce the highest production capacity they can safely and reliably maintain each day – since the baseload units are also the most efficient units. If the units occasionally produced more than that capacity for less than 5% of the hours, that was judged to not be reliably effective capacity for planning purposes.

The maximum effective capacity assumed for modeling in the resource adequacy analysis is summarized in the table below and the supporting analysis for each unit is discussed in the pages that follow in this appendix.

Table A-11: Summary of Available Thermal Generator Capacity in FY2024

Generator Name	Start of Operations	Fuel	Nameplate Capacity (MW)	Available Capacity (MW)
AES 1	2002	Coal	227	227
AES 2	2002	Coal	227	227
Aguirre Combined Cycle 1	1977	Diesel	296	220
Aguirre Combined Cycle 2	1977	Diesel	296	100
Aguirre Steam 1	1971	Bunker	450	350
Aguirre Steam 2	1971	Bunker	450	330
Costa Sur 5	1972	Natural Gas	410	350
Costa Sur 6	1973	Natural Gas	410	350
EcoElectrica	1999	Natural Gas	535	535
Palo Seco 3	1968	Bunker	216	190
Palo Seco 4	1968	Bunker	216	190
San Juan 7	1965	Bunker	100	70
San Juan 9	1968	Bunker	100	90
San Juan Combined Cycle 5	2008	Diesel / Natural Gas	220	200
San Juan Combined Cycle 6	2008	Diesel / Natural Gas	220	200
Cambalache 2	1998	Diesel	82.5	75
Cambalache 3	1998	Diesel	82.5	75
Mayagüez 1	2009	Diesel	55	50

Generator Name	Start of Operations	Fuel	Nameplate Capacity (MW)	Available Capacity (MW)
Mayagüez 2	2009	Diesel	55	25
Mayagüez 3	2009	Diesel	50	50
Mayagüez 4	2009	Diesel	50	50
Palo Seco Mobile Pack 1-3[3]	2021	Diesel	27 each (81 total)	81
7 Gas Turbines (Peakers)[4]	1972	Diesel	21 each (147 total)	147
Total			**4,976**	**4,182**

Figure A-23: San Juan CC 5, Hourly Generation – 2020–2022

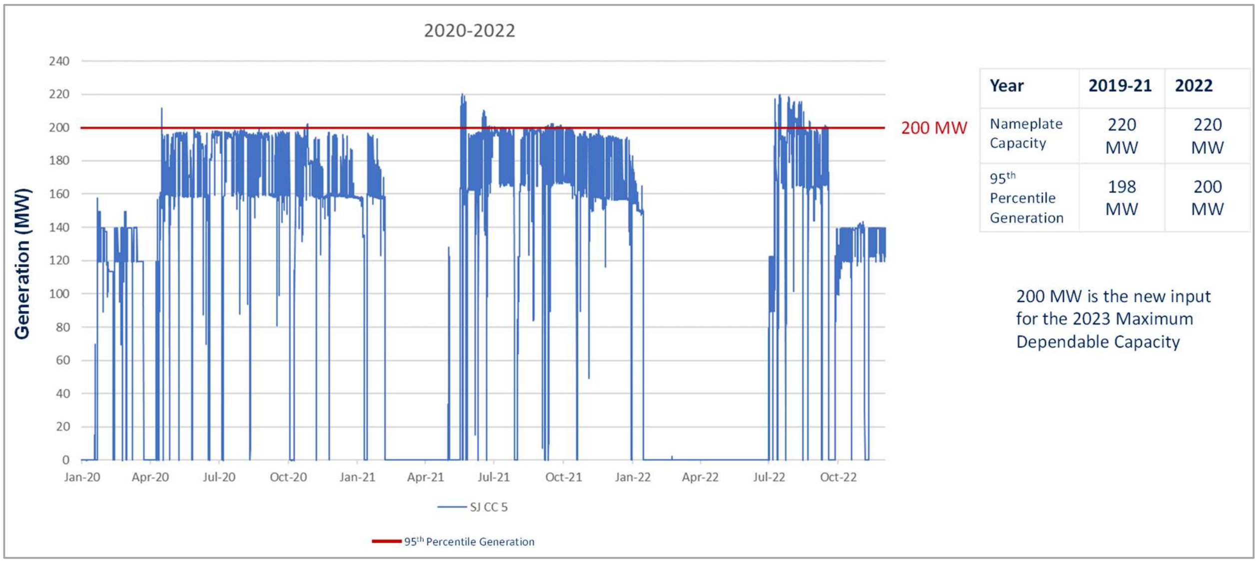


Figure A-24: San Juan CC 6, Hourly Generation – 2020–2022

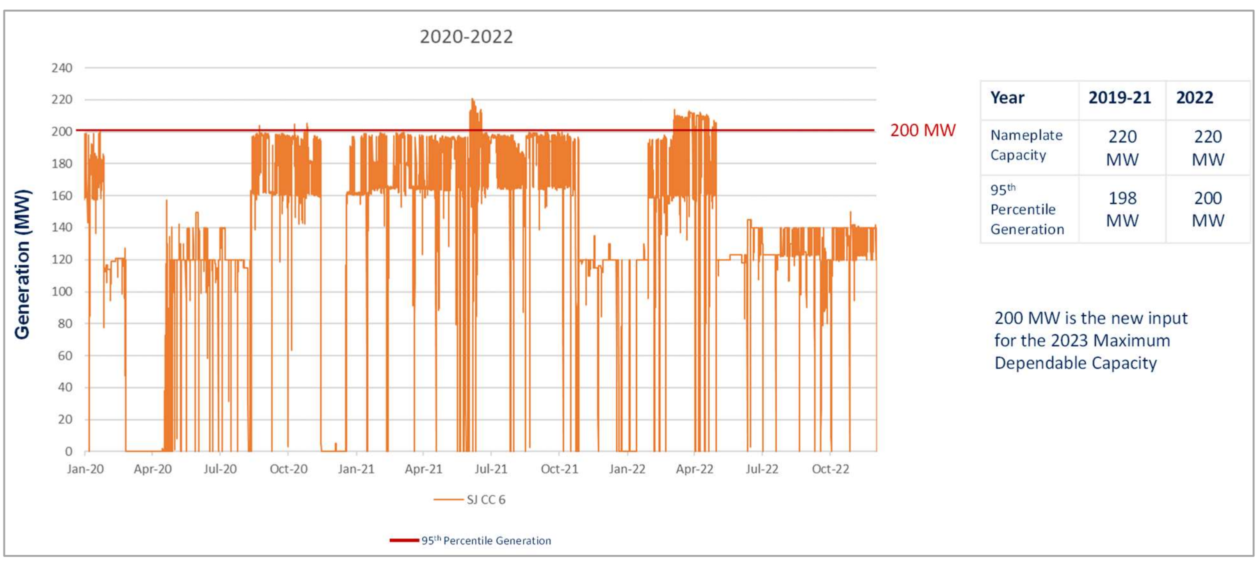


Figure A-25: San Juan 7, Hourly Generation – 2020–2022

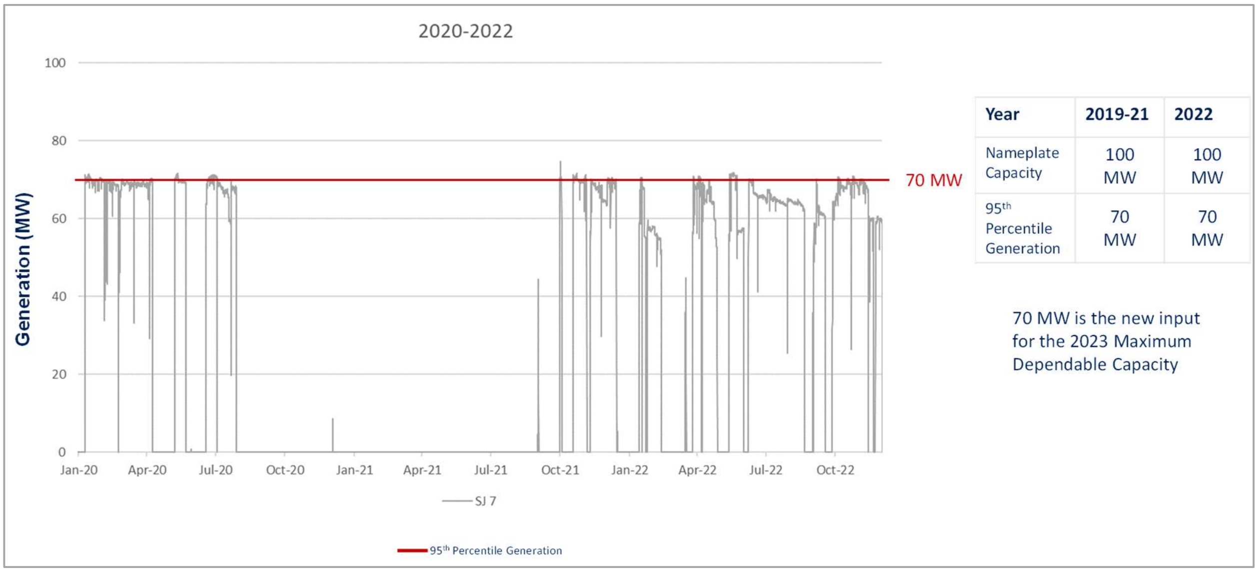


Table A-12: San Juan 8, Hourly Generation – 2020–2022

Nameplate Capacity	100 MW
95th Percentile Generation (2021)	0 MW
Maximum Dependable Capacity	0 MW

San Juan 8 is out of service.

Figure A-26: San Juan 9, Hourly Generation – 2020–2022

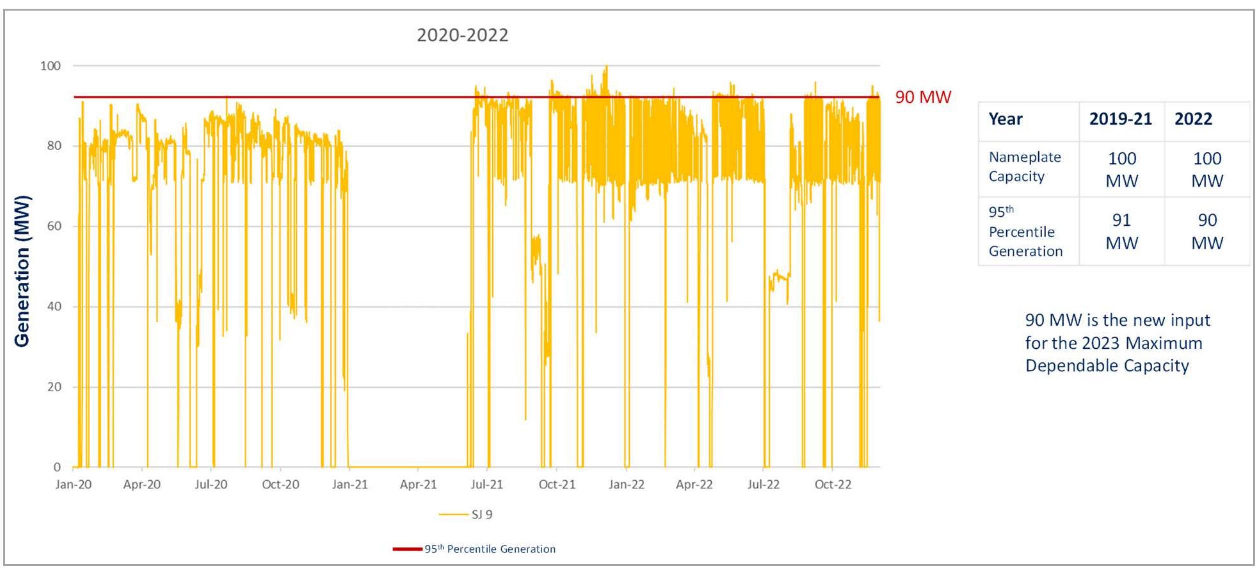


Table A-13: San Juan 10, Hourly Generation – 2020–2022

Nameplate Capacity	100 MW
95th Percentile Generation (2021)	0 MW
Maximum Dependable Capacity	0 MW

San Juan 10 is out of service.

Table A-14: Palo Seco 1, Hourly Generation – 2020–2022

Nameplate Capacity	85 MW
95th Percentile Generation (2021)	0 MW
Maximum Dependable Capacity	0 MW

Palo Seco 1 is out of service.

Table A-15: Palo Seco 2, Hourly Generation – 2020–2022

Nameplate Capacity	85 MW
95th Percentile Generation (2021)	0 MW
Maximum Dependable Capacity	0 MW

Palo Seco 2 is out of service.

Figure A-27: Palo Seco 3, Hourly Generation – 2020–2022

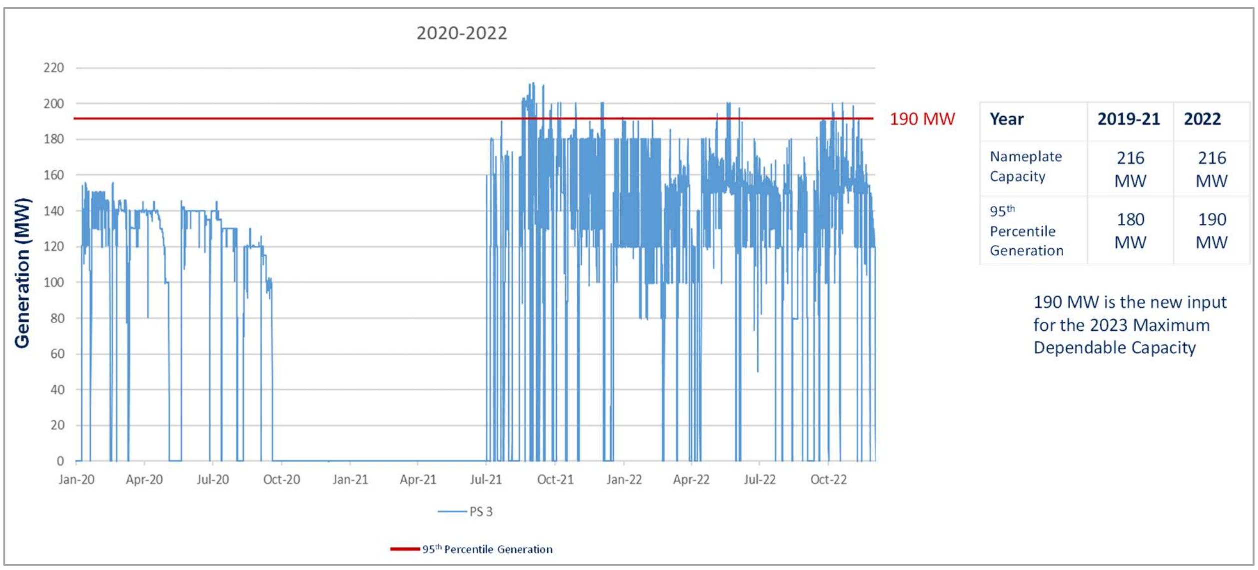
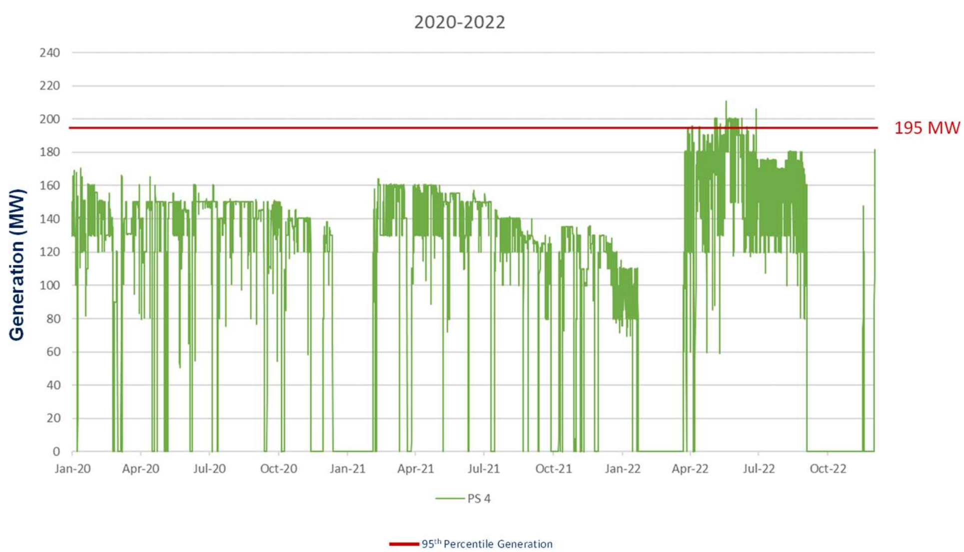


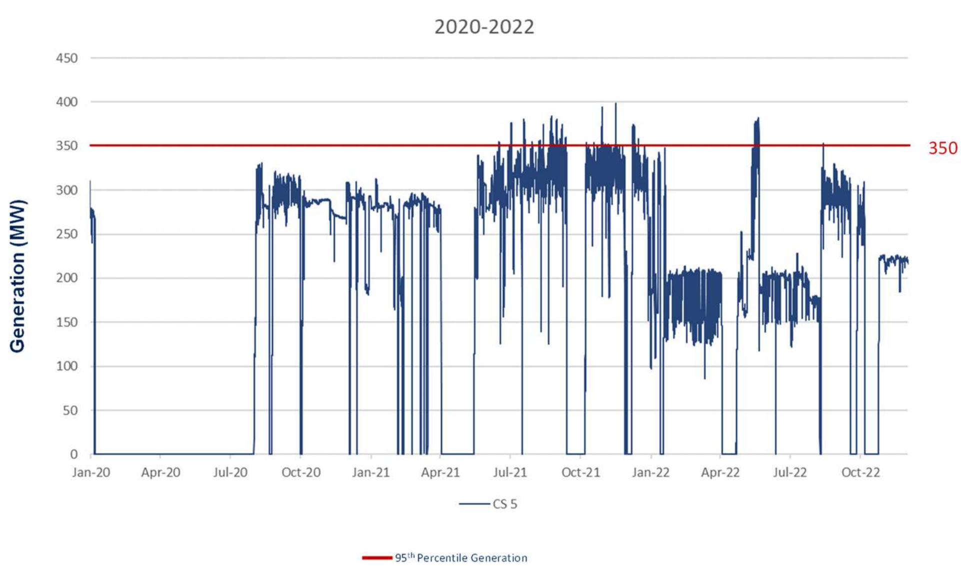
Figure A-28: Palo Seco 4, Hourly Generation – 2020–2022



Year	2019-21	2022
Nameplate Capacity	216 MW	216 MW
95th Percentile Generation	160 MW	195 MW

190 MW is the new input for the 2023 Maximum Dependable Capacity

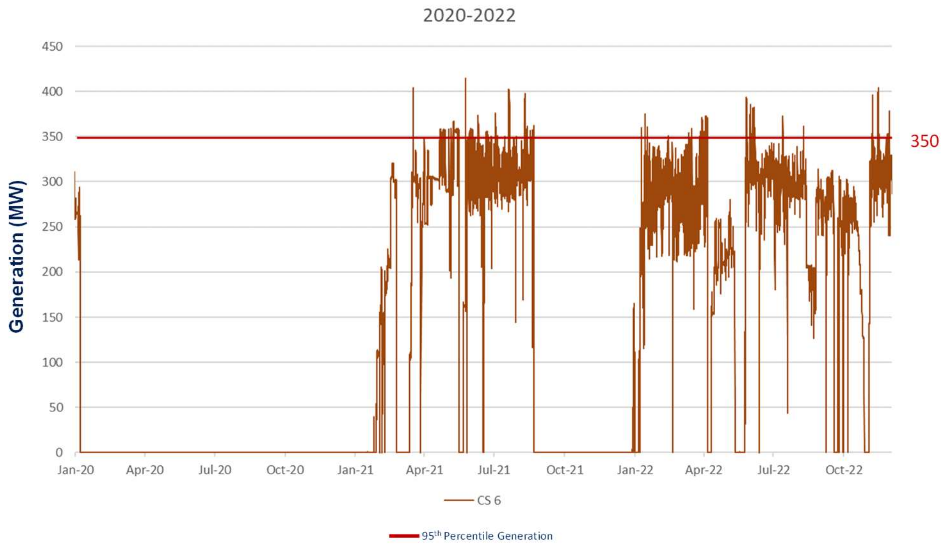
Figure A-29: Costa Sur 5, Hourly Generation – 2020–2022



Year	2019-21	2022
Nameplate Capacity	410 MW	410 MW
95th Percentile Generation	329 MW	350 MW

350 MW is the new input for the 2023 Maximum Dependable Capacity

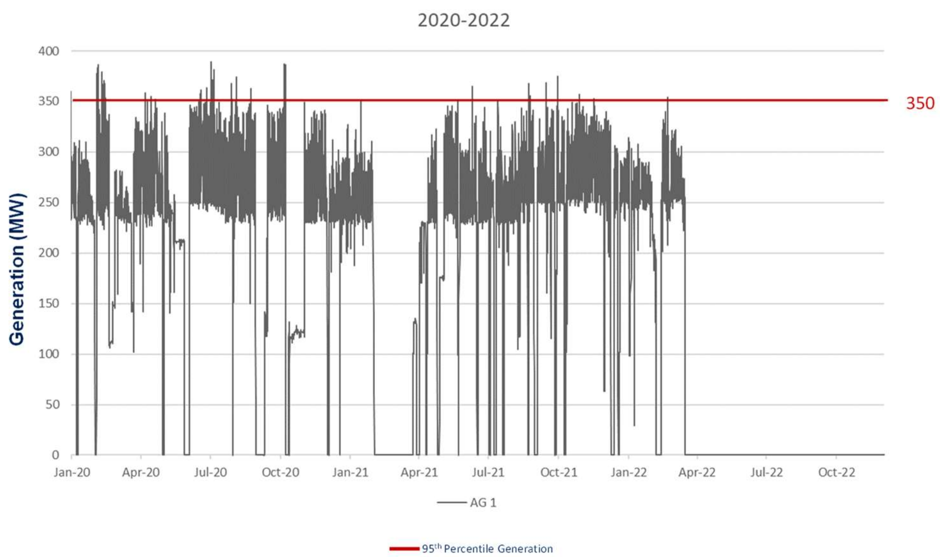
Figure A-30: Costa Sur 6, Hourly Generation – 2020–2022



Year	2019-21	2022
Nameplate Capacity	410 MW	410 MW
95th Percentile Generation	322 MW	350 MW

350 MW is the new input for the 2023 Maximum Dependable Capacity

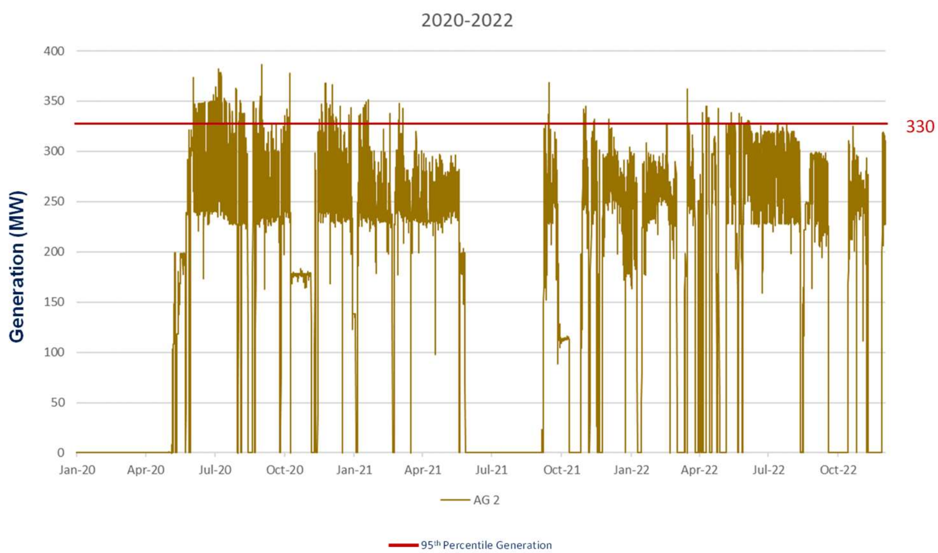
Figure A-31: Aguirre 1, Hourly Generation – 2020–2022



Year	2019-21	2022
Nameplate Capacity	450 MW	450 MW
95th Percentile Generation	335 MW	350 MW

350 MW is the new input for the 2023 Maximum Dependable Capacity

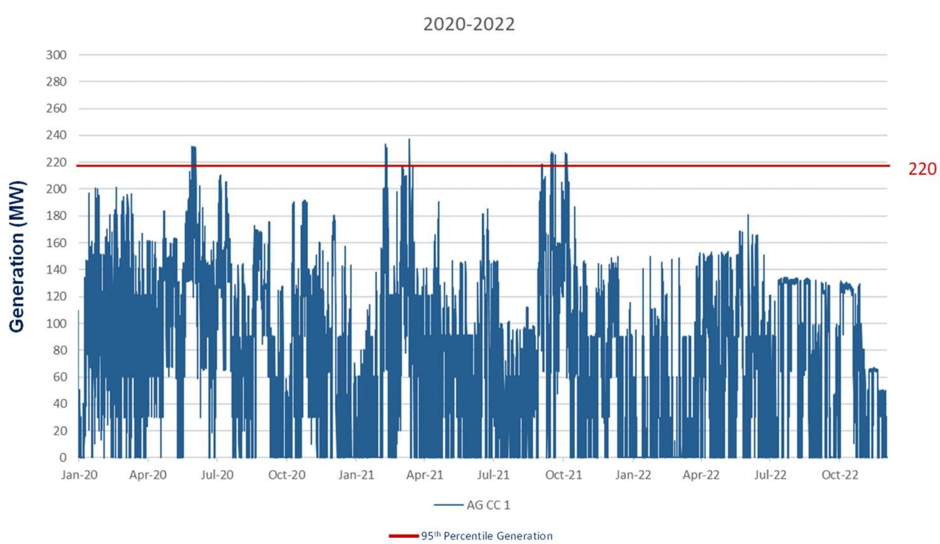
Figure A-32: Aguirre 2, Hourly Generation – 2020–2022



Year	2019-21	2022
Nameplate Capacity	450 MW	450 MW
95th Percentile Generation	304 MW	330 MW

330 MW is the new input for the 2023 Maximum Dependable Capacity

Figure A-33: Aguirre 1 CC, Hourly Generation –2020–2022

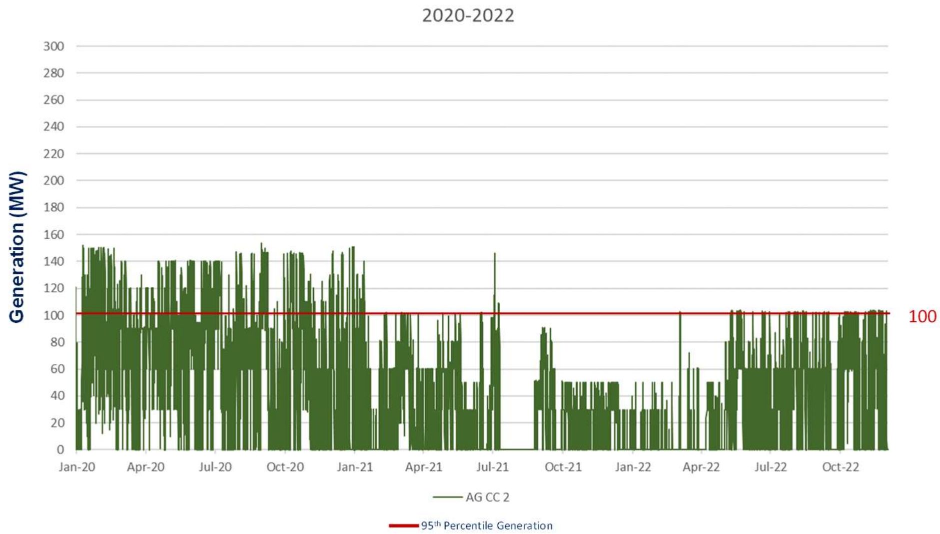


Year	2019-21	2022
Nameplate Capacity	296 MW	296 MW
95th Percentile Generation	190 MW	220 MW

220 MW is the new input for the 2023 Maximum Dependable Capacity

Aguirre CC 1 will now be modeled as 2 units each with 110 MW Maximum Dependable Capacity

Figure A-34: Aguirre 2 CC, Hourly Generation – 2020–2022



Year	2019-21	2022
Nameplate Capacity	296 MW	296 MW
95th Percentile Generation	130 MW	100 MW

100 MW was previously chosen as the Maximum Dependable Capacity

Aguirre CC 2 will now be modeled as 2 units each with 50 MW Maximum Dependable Capacity

Appendix 11. Results – Loss of Load Expectation

The following appendix provides more detail regarding the resource adequacy results that are summarized in the main body of this report.

Loss of Load Expectation

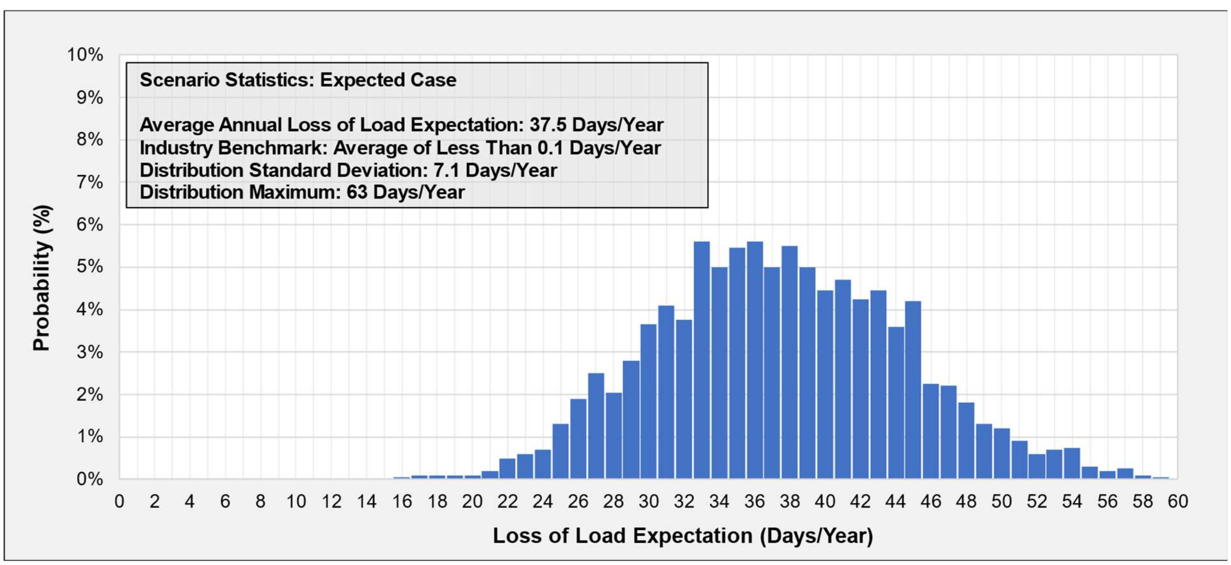
The following table summarizes the LOLE calculations for the current system in FY2024.

Table A-16: Calculated Loss of Load Expectation, Current System (FY2024)

Measure	Loss of Load Expectation (LOLE)
Average	37.5 Days / Year
Industry Benchmark Target	0.1 Days / Year
Distribution Standard Deviation	7.1 Days / Year
Distribution Maximum	63 Days / Year

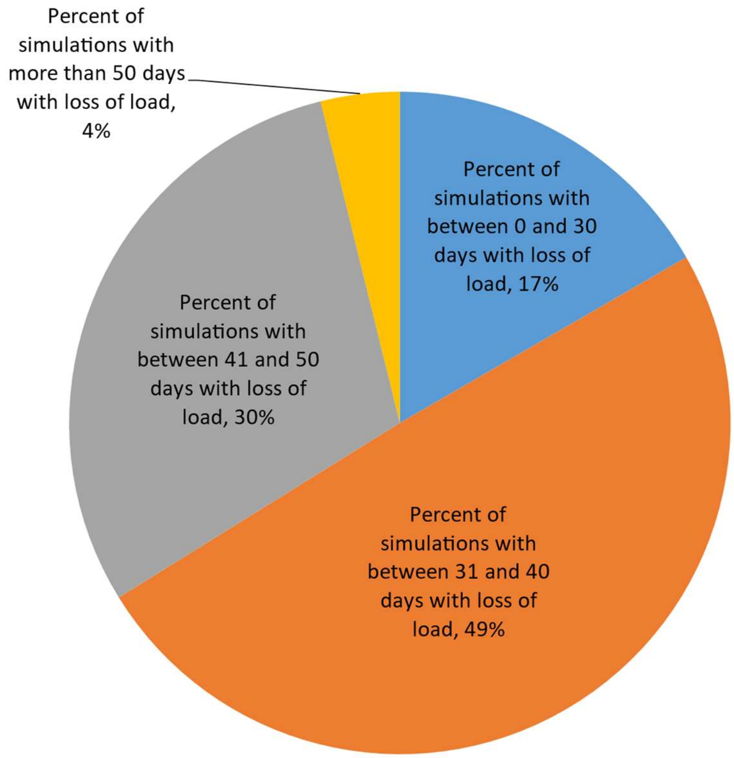
The following figure presents the probability of LOLE at various levels. The vertical axis represents probability, while the horizontal axis represents the number of days per year where system generators could not fully serve load. Based on the distribution, 37.5 days of loss of load is the most likely outcome. There is approximately a 50% probability that the number of days of loss of load will be equal to or greater than 38 days. Note that the figure does not forecast what will actually occur with respect to resource adequacy in FY2024; however, the figure does help to quantify the risk, or probability, of how many loss of load days might be expected in FY2024.

Figure A-35: Loss of Load Expectation Probability Chart, FY2024



The data in the previous figure can also be summarized in the following pie chart. A total of 79% of the simulations performed had between 31 and 50 days of loss of load.

Figure A-36: Loss of Load Expectation Pie Chart



The graph breaks down the annual days of loss of load based on the distribution of the Monte Carlo simulations performed

Various characteristics of the Puerto Rico electric system help explain the wide distribution in LOLE:

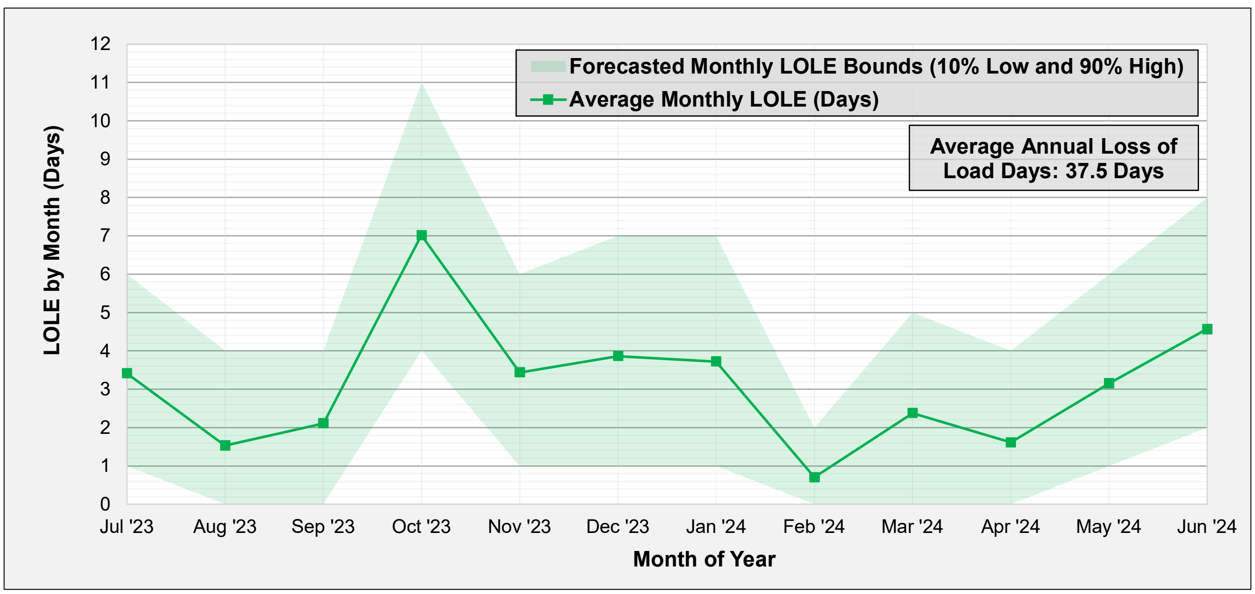
- The forced outage rates for the existing power plants are generally very high, meaning the power plants break down frequently. If different power plants happen to break down at the same time, which is common in Puerto Rico, then there is significant risk that there will not be enough remaining generators available to cover the load. As power plants go offline for outages (whether planned or forced), the remaining power plants must increase output to meet system load. This places some level of additional stress on the remaining power plants, which can compound the risk of loss of load for the system – specifically if the stress on the remaining power plants results in them breaking down more frequently or requiring them to take more frequent planned maintenance.
- In addition, the power plants in Puerto Rico sometimes require prolonged planned maintenance outages due to their poor current condition. Whenever a power plant is on a planned maintenance outage, it is unable to generate electricity.
- As a relatively small island, Puerto Rico is both unable to import electricity from neighbors, and has a limited number of power plants that can generate electricity. By comparison, a larger utility on the U.S. mainland can not only import electricity from neighboring utilities during times of need, but also has many available power plants that can be started or ramped up to meet load in times of need. In Puerto Rico, the loss of a single large power plant (either for planned

maintenance or a forced outage), like EcoElectrica, the Aguirre Steam units, Costa Sur, or AES, immediately reduces the total available generating capacity in Puerto Rico by roughly 10%. If one of these units is out of service, electricity must be supplied by other generators, many of which are either already being fully utilized, or are unreliable and break down frequently.

The following figure shows LOLE (for all 2,000 simulations) broken out by month. The dark line represents the average calculated LOLE, while the shading around the middle line represents the calculated monthly LOLE distribution's 10% low and 90% high values for each month – the shading provides an illustration of the range of calculated potential LOLE outcomes for each month. For example, for the month of October 2023, the calculated average LOLE was approximately 7 days, with the worst 10% of simulations having 11 or more days of load shed, while the best 10% of simulations having 4 or less days of load shed. As a result, one might expect load shed for the month of October 2023 to fall somewhere between the range of 4 days to 11 days, with 7 days being the most likely outcome.

LOLE was found to be highest during October 2023, December 2023, January 2024, and June 2024. The months of October, December, and January have a high number of planned maintenance outages to the major generators. During maintenance outages of large generators, any additional forced outages to other generators could result in island load shed. In general, while planned outages to large generators can result in higher load shed risk, it is difficult to reschedule outages to large generators in Puerto Rico in a different way that would result in a significant improvement to the annual resource adequacy performance of the system. The reason for this is because there are only so many times when the generators can be scheduled to minimize the impact to the system and the generators often require extended maintenance time due to their age and condition. LOLE for the month of June is mainly due to the high system peak demand.

Figure A-37: Loss of Load Expectation Monthly Breakdown



Appendix 12. Results – Loss of Load Hours

The following appendix provides more detail regarding the resource adequacy results that are summarized in the main body of this report.

Loss of Load Hours

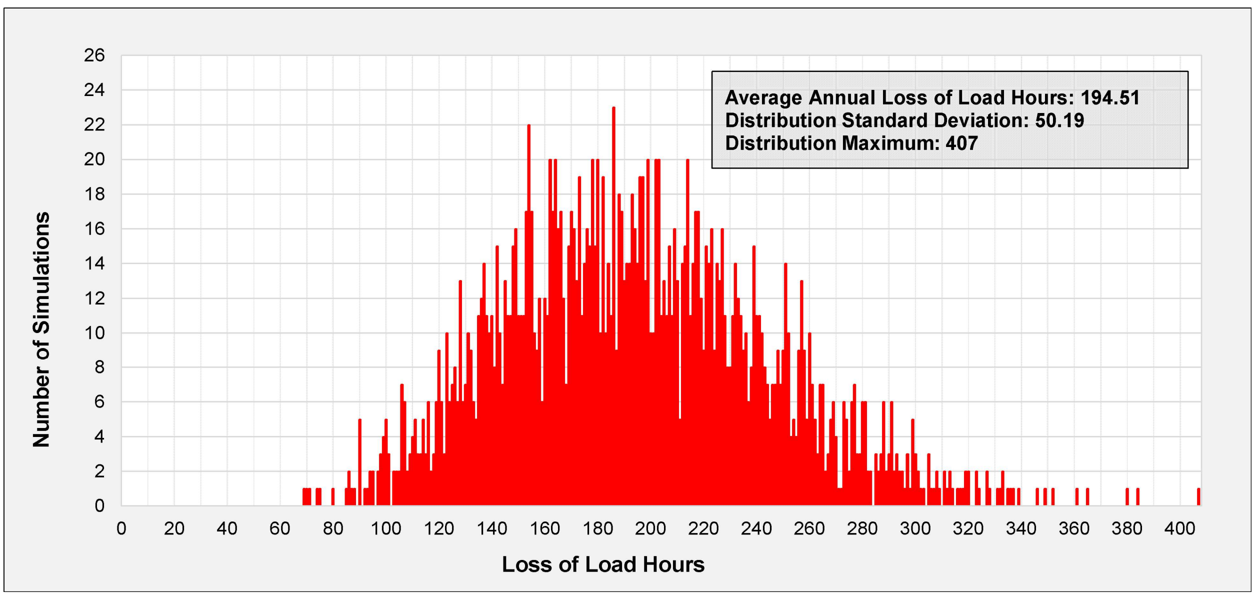
The following table summarizes the LOLH calculations for the current system in FY2024.

Table A-17: Calculated Loss of Load Hours, Current System (FY2024)

Measure	Loss of Load Hours (LOLH)
Average	194.5 Hours / Year
Standard Deviation	50.2 Hours/ Year
Maximum	407 Hours / Year

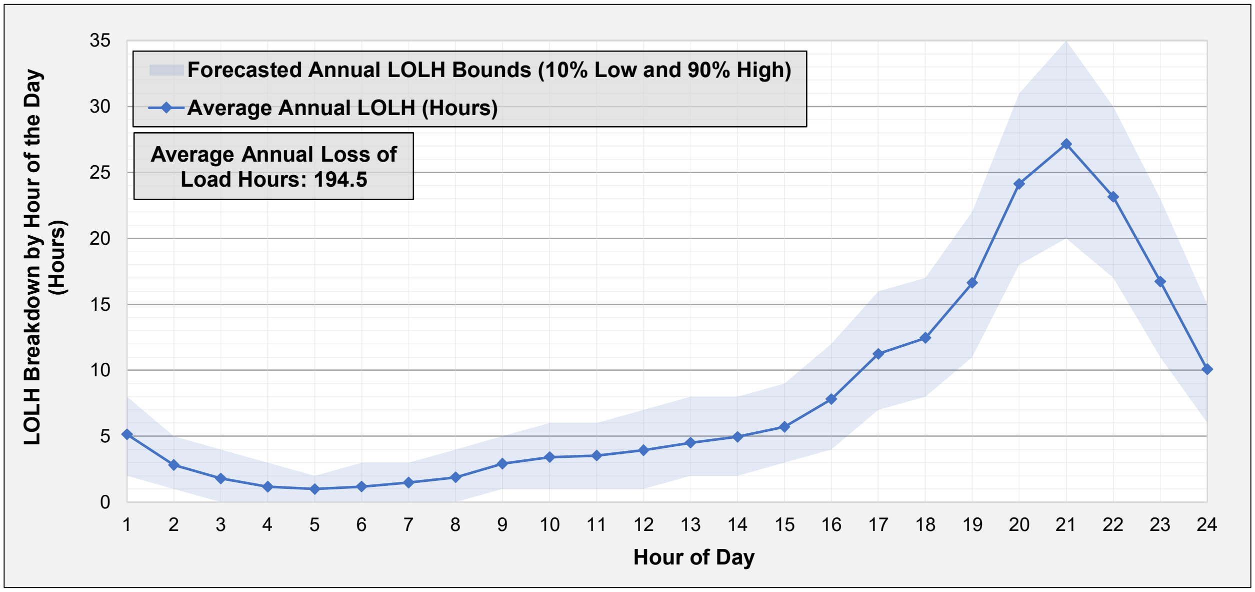
A similar histogram as provided for LOLE in the previous appendix is also provided for LOLH below. One simulation had 407 LOLH, which was the maximum for all simulations performed.

Figure A-38: Distribution of Loss of Load Hour Results



The following figure presents the average number of LOLH (for all the 2,000 simulations), broken out by hour of the day. In the figure, if one were to sum each individual hour, it would total 194.5 LOLH, which is the average annual LOLH over all the simulations. Similar to the monthly LOLE figure in Appendix 11, the shading represents the calculated annual LOLH distribution's 10% low and 90% high values for each hour – the shading provides an illustration of the range of calculated potential LOLH outcomes for each hour over the course of the year. The majority of LOLH are observed during the evening hours, when system load is highest and when solar production is diminished or unavailable to the electric system. Approximately 62% of the observed LOLH in the resource adequacy simulation were observed to occur from 6 p.m. and 11 p.m.

Figure A-39: Calculated Loss of Load Hours Broken Out by Hour of the Day

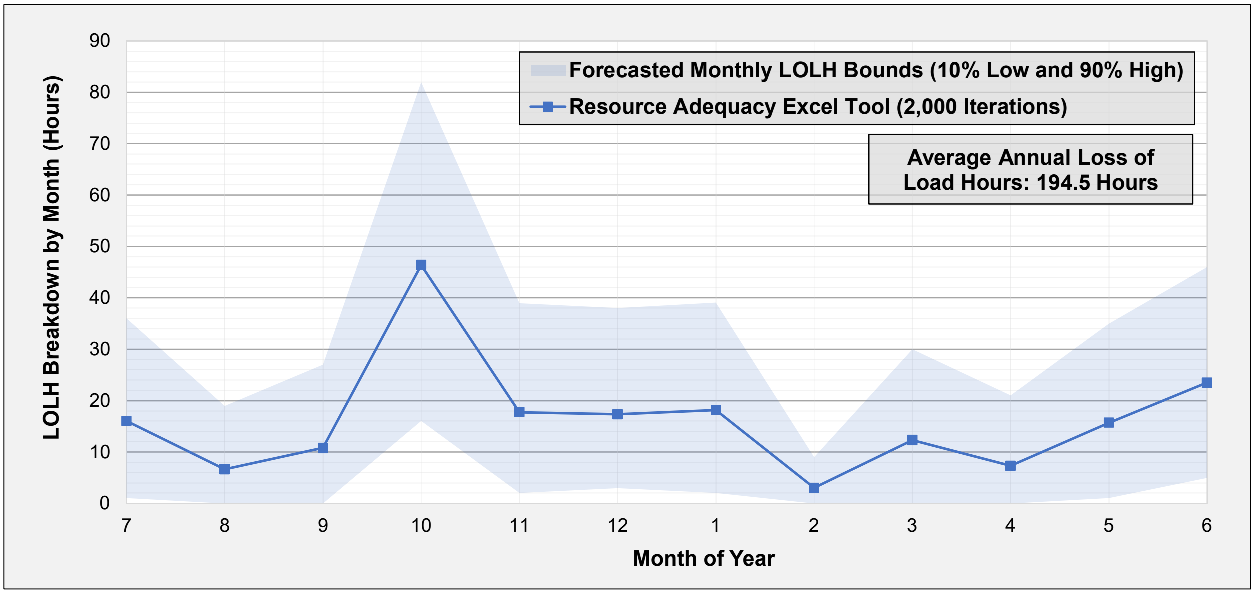


From the perspective of improving system resource adequacy (i.e., reducing LOLE), the results indicate that the most effective solutions will be those targeted at being able to help meet load during the evening peak. For example, additional stand-alone solar generators should be able to help overall system resource adequacy, but only during times when the sun is up, which reflects just over a third of the hours when the simulated LOLH were found to occur. As such, the results illustrate that additional standalone solar generators will have little impact on improving LOLE. The reason for this is because if there was a generation shortfall event that spanned an entire day (i.e., a forced outage to a large thermal generator), additional solar would help to mitigate potential loss of load during the middle of the day (and thus reduce mid-day LOLH), but during the evening the generator shortfall event would still drive load shed since the solar is not able to generate after the sun has set (a single hour of load shed, LOLH, regardless of when it occurs, equates to a day LOLE). In other words, the additional standalone solar might be able to prevent the load shed event from occurring mid-day, but it would not be able to prevent it from occurring in the evening; thus, the additional standalone solar would not be able to significantly help improve system LOLE.

In contrast, an energy storage system, reciprocating engine, or other dispatchable unit would be better able to provide energy during the evening peak load; thus, would be most effective at improving overall system resource adequacy.

The figure below shows LOLH broken out by month. LOLH were found to be highest during October (2023) and June (2024) because these months respectively correspond to the highest MW of units scheduled for planned outage (October) and the high system load (June). An additional contribution to LOLH is maintenance outages of large generators. During maintenance outages of large generators, any additional forced outages to other generators could result in LOLH. Similar to the previous graph, the shading represents the calculated monthly LOLH distribution’s 10% low and 90% high values – the shading provides an illustration of the range of calculated potential LOLH outcomes for each month.

Figure A-40: Calculated Loss of Load Hours Broken Out by Month of the Year



Appendix 13. Results – Expected Unserved Energy

EUE is the number of megawatt hours (MWh) of load that will not be served in a specific time interval because load exceeds generation. This measure helps to provide an indication on the level of generation shortfall associated with LOLHs. The average annual EUE over all simulations performed is provided in the table below.

Table A-18: Expected Unserved Energy

Measure	Value
Total Average EUE per Year, Averaged Over All Simulations	32.6 GWh

The following figures also provide an illustration of EUE magnitude at different times. The graphs present EUE as a function of hour of the day and month of the year. The graphs generally show that EUE is marginally higher for the time periods where there is a higher risk of LOLH. Note the summing the individual data points below will not equate to the value in the above table. This is because the value in the table reflects the average annual EUE over all simulations, while the data point values below reflect the average number of MWs shortfall just for the hours when loss of load was observed.

Figure A-41: Calculated Expected Unserved Energy Broken Out by Hour of Day

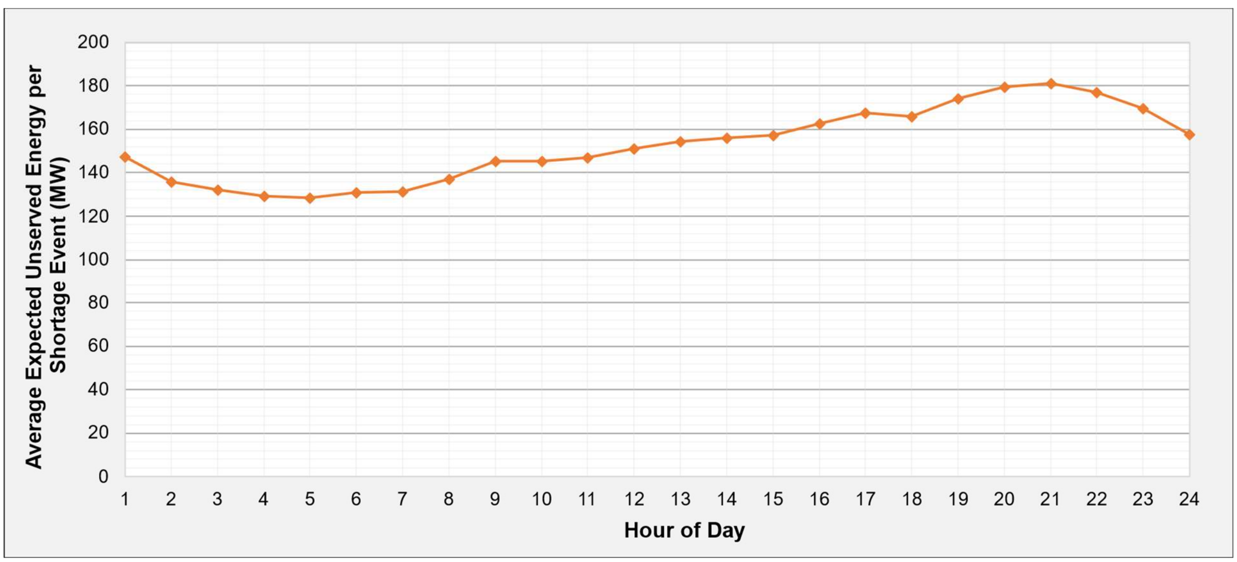
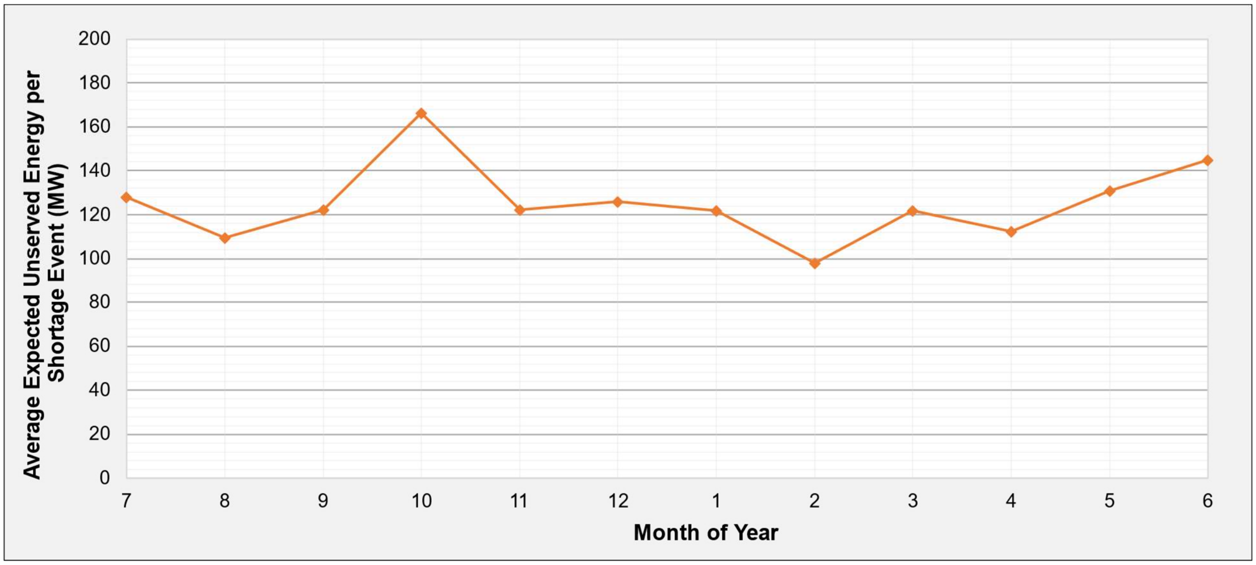


Figure A-42: Calculated Expected Unserved Energy Broken Out by Month of the Year



Appendix 14. Results – Reserve Margin

The average system reserve margin by hour and month was calculated, based on an average over all the simulations performed. This information is illustrated in the following figure. Each input in the figure reflects the average available capacity during that hour and month. Available capacity includes both the available capacity of thermal generators and any dependable capacity from operating renewable generators.

Times that correspond to higher LOLH risk are highlighted in various shades of red, the darkest times corresponding to highest LOLH risk. The values in the table are the average over all simulations. In general, times when the available capacity drops below 500 MW correspond to a higher risk of demand not being served in Puerto Rico. Under this threshold, the loss of a single large generator can result in a shortfall of generation to meet demand. The average available capacity to load is lowest in the evening hours, when system load is highest.

The figure illustrates that while the PRM in Puerto Rico is approximately 67%, due to high forced outage rates of the generators on the island, the ratio or actual available capacity to load is substantially lower.

Figure A-43: Reserve Margin Capacity

Hour of Day	Month of Year												
	7	8	9	10	11	12	1	2	3	4	5	6	**Average**
1	698	895	882	655	707	706	676	1,017	850	856	779	640	**780**
2	807	987	971	730	786	809	784	1,105	946	955	863	743	**874**
3	881	1,064	1,038	785	848	868	851	1,173	1,018	1,034	947	824	**944**
4	935	1,120	1,081	819	910	911	900	1,219	1,071	1,074	1,003	898	**995**
5	964	1,156	1,108	831	938	938	913	1,217	1,099	1,099	1,046	938	**1,021**
6	964	1,153	1,092	797	922	912	897	1,220	1,064	1,096	1,020	933	**1,006**
7	971	1,134	1,069	781	847	853	857	1,133	1,001	1,058	1,019	951	**973**
8	938	1,126	1,056	748	846	836	826	1,101	984	1,029	972	913	**948**
9	883	1,063	996	668	803	794	777	1,060	936	987	917	846	**894**
10	857	1,022	952	624	772	797	745	1,042	916	972	888	826	**868**
11	862	1,019	936	608	779	822	737	1,031	930	982	890	842	**870**
12	867	1,014	895	571	766	837	737	1,042	928	957	888	865	**864**
13	874	1,000	886	553	739	840	711	1,044	911	959	887	842	**854**
14	872	983	864	521	722	830	719	1,040	924	967	883	839	**847**
15	837	948	834	494	699	810	704	1,020	901	955	840	787	**819**
16	788	888	794	446	641	747	647	986	869	898	775	704	**765**
17	728	848	760	416	568	623	580	916	789	826	694	615	**697**
18	671	829	745	417	545	565	528	875	743	780	660	571	**661**
19	644	810	709	314	477	483	487	829	700	749	631	540	**614**
20	596	713	617	290	420	382	375	711	574	653	566	489	**532**
21	465	634	601	301	427	408	384	723	559	609	477	391	**498**
22	468	637	634	352	453	453	447	760	588	641	491	384	**526**
23	508	699	704	437	511	518	496	815	650	682	543	429	**583**
24	581	781	796	553	602	609	569	907	718	757	639	519	**669**
Average	**778**	**938**	**876**	**571**	**697**	**723**	**681**	**999**	**861**	**899**	**805**	**722**	**796**

Appendix 15. Sensitivity Analysis – Introduction

A number of different sensitivity analyses are performed for this report. The sensitivity analyses performed reflect changes starting from the current system. A list of the different analyses performed is provided below.

1. **Current System (Expected Case).** Baseline model based on system operation in FY2024. This scenario reflects the baseline comparison to all of the additional sensitivity analyses listed below. Puerto Rice has a relatively small number of total generators available to be dispatched at any point in time. As a result, it is frequently at a high risk of not being able to serve load in the event of a loss of a large generator due to the simple fact that there is a limited number of other generators that could be dispatched to cover for the large generator's outage. Also, the forced outage times of the other generators have historically been much longer than expected. Results from this scenario are described in Appendix 11 through Appendix 14.
2. **New Emergency Generation.** This scenario analyzes the operational impact of adding various amount of emergency generation, totaling 150 MW, 350 MW, and 700 MW. The emergency generation is modeled as operational for the entire fiscal year. In addition to helping improve overall system resource adequacy, one of the key benefits of additional emergency generation is it would allow the existing baseload generators to be temporarily taken offline for much needed maintenance.
3. **Early Retirement of the AES Coal Power Plant.** This sensitivity simulation illustrates the resource adequacy impact of the early retirement of the AES Coal Power Plant from the current system model. Also investigated is the impact of the early retirement of the AES Coal Power Plant along with the addition of the Tranche 1 projects (845 MW of new solar generation paired with 220 MW of 4-hr duration BESS).
4. **Meeting Industry LOLE Benchmarks.** This sensitivity simulation determines how much additional 'perfect' generation capacity would need to be added to the Puerto Rico electrical system in order for an LOLE target of 0.10 days/year to be met. For reference, 'perfect' generation capacity is equivalent to a generator that can operate 100% of the time, for every hour of the year. Equivalently, it can be considered as a constant MW reduction in load for every hour of the year. The goal of this simulation is to quantify the generation shortfall in Puerto Rico. While no generator is "perfect," identifying how many MW of perfect capacity are needed helps to provide a best-case estimate of what would be required in terms of generation (or load reduction) to bring Puerto Rico in line with a 0.10 days/year LOLE target.
5. **New Solar Addition.** This sensitivity simulation illustrates the impact of adding 845 MW of new solar generation to the current system model. For this sensitivity, all added solar is assumed to be standalone solar, meaning none of the MW are considered to be paired with energy storage. Separate sensitivity simulations which consider energy storage are listed below.
6. **New Standalone BESS Addition.** This sensitivity simulation illustrates the impact of adding 220 MW of 4-hr duration standalone battery energy storage systems (BESS) to the current system model.
7. **New Solar Paired with BESS Addition.** This sensitivity simulation illustrates the impact of adding 845 MW of new solar generation paired with 220 MW of 4-hr duration BESS to the current system model. The total amount of added solar and BESS resources added for this simulation are consistent with the total amounts from the Tranche 1 projects.
8. **New Flexible Combined Cycle Thermal Resource.** This sensitivity simulation illustrates the impact of adding a new 330 MW combined cycle resource to the current system model.

9. **New Flexible Combustion Turbine Thermal Resources.** This sensitivity simulation illustrates the impact of adding a fleet of new, smaller flexible combustion turbine thermal resources to the current system model. A total of 11 new 21 MW resources (231 MW total) are added for this simulation.
10. **Additional Distributed Solar Resources.** This sensitivity simulation adds 250 MW of distributed solar PV to the system in order to estimate the associated resource adequacy impact.
11. **New Demand Response Resources.** This sensitivity simulation illustrates the resource adequacy impact of adding demand response (DR) resources (i.e., short-term reductions in system load) to the current system model in varying MW levels.
12. **Load Sensitivity.** This scenario investigates the impact of lower system load on system resource adequacy.
13. **Addition of Electric Vehicle Load.** This scenario examines the resource adequacy impact of increasing levels of electric vehicle penetration in Puerto Rico.
14. **Effective Load Carry Capability.** A set of appendices are provided at the end of this report that explain the concept of ELCC and perform ELCC calculations for solar PV, energy storage, and solar PV paired energy storage resources in Puerto Rico.

Appendix 16. Sensitivity Analysis – Comparison of Scenario Results

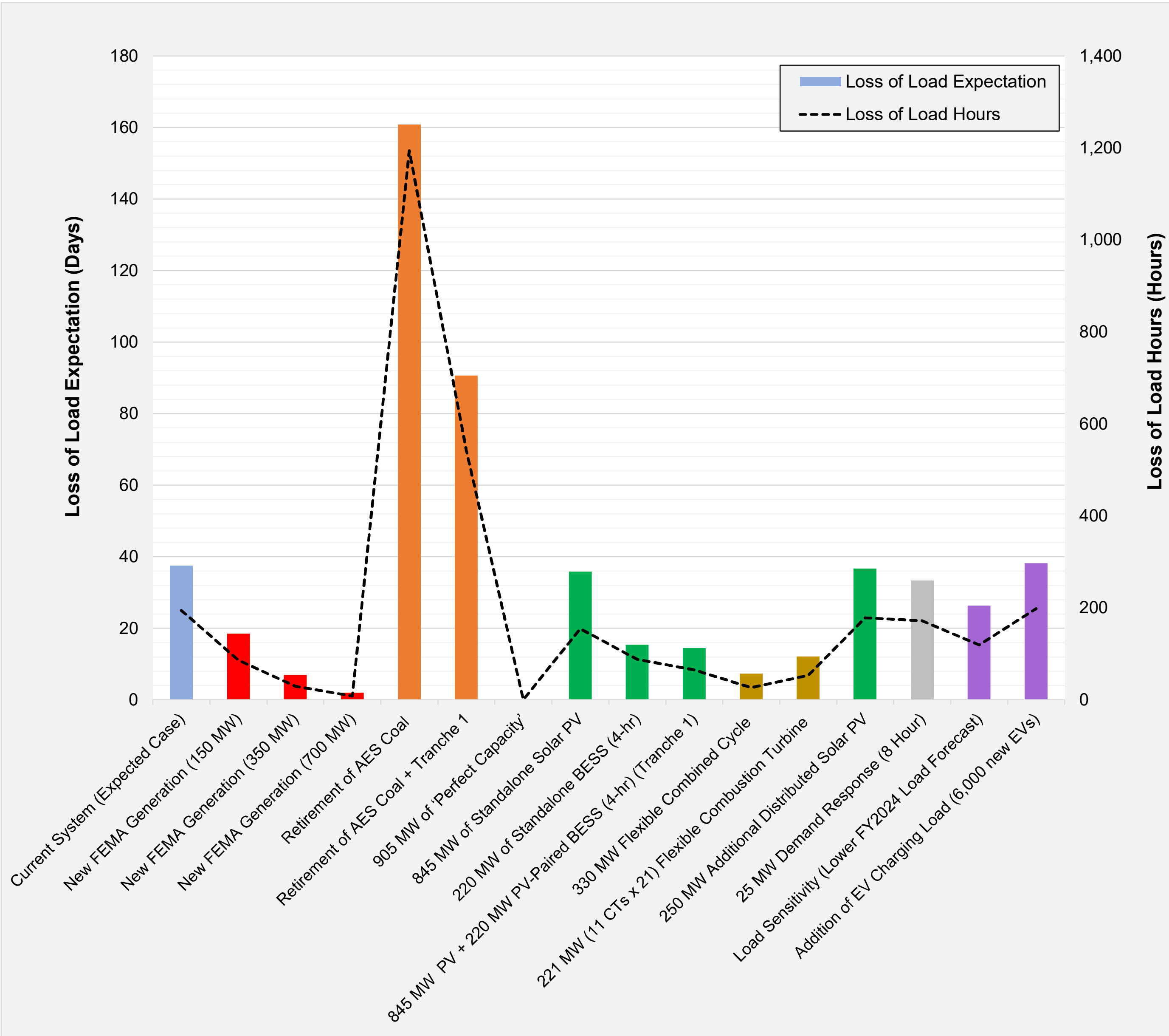
The following table summarizes the LOLE and LOLH model results for the various sensitivity analyses performed.

Table A-19: Calculated Resource Adequacy Risk Measures – All Sensitivity Cases

<table>
<tr><th colspan="2">Scenario</th><th>Loss of Load Expectation (LOLE), Days / Year</th><th>Loss of Load Hours (LOLH), Hours / Year</th></tr>
<tr><td colspan="2">Current System (Expected Case)</td><td>37.5</td><td>194.5</td></tr>
<tr><td rowspan="13">Current System +</td><td>New Emergency Generation (150 MW)</td><td>18.5</td><td>86.5</td></tr>
<tr><td>New Emergency Generation (350 MW)</td><td>7.0</td><td>29.4</td></tr>
<tr><td>New Emergency Generation (700 MW)</td><td>2.0</td><td>8.5</td></tr>
<tr><td>Retirement of AES Coal</td><td>160.8</td><td>1,193.6</td></tr>
<tr><td>Retirement of AES Coal + Tranche 1 (845 MW Solar PV + 220 MW 4-hr BESS)</td><td>90.7</td><td>542.6</td></tr>
<tr><td>905 MW of ‘Perfect Capacity’</td><td>0.1</td><td>0.3</td></tr>
<tr><td>845 MW of Standalone Solar PV</td><td>35.9</td><td>154.6</td></tr>
<tr><td>220 MW of Standalone BESS (4-hr)</td><td>15.4</td><td>87.8</td></tr>
<tr><td>845 MW Solar PV + 220 MW Solar-Paired BESS (4-hr) (Tranche 1 Projects)</td><td>14.5</td><td>65.1</td></tr>
<tr><td>330 MW Flexible Combined Cycle</td><td>7.3</td><td>26.5</td></tr>
<tr><td>221 MW (11 CTs x 21) Flexible Combustion Turbine</td><td>12.1</td><td>53.3</td></tr>
<tr><td>250 MW Additional Distributed Solar PV</td><td>36.7</td><td>178.4</td></tr>
<tr><td>25 MW Demand Response (8 Hour)</td><td>33.4</td><td>172.1</td></tr>
<tr><td colspan="2">Load Sensitivity (Lower FY2024 Load Forecast)</td><td>26.3</td><td>119.2</td></tr>
<tr><td colspan="2">Addition of Electric Vehicle Charging Load (6,000 new EVs)</td><td>38.2</td><td>198.0</td></tr>
<tr><td colspan="2">Industry Benchmark Target</td><td>0.1</td><td>—</td></tr>
</table>

The figure below illustrates the LOLE and LOLH for all scenarios.

Figure A-44: Scenario Loss of Load Expectation and Loss of Load Hours



Appendix 17. Sensitivity Analysis – New Emergency Generation

A sensitivity scenario was performed to investigate the impact to system resource adequacy of adding various amounts of emergency generation to the electrical system. Specifically, this scenario analyzes the potential improvement to system resource adequacy of adding 150 MW, 350 MW, and 700 MW of emergency generation to the existing generation fleet. The generation is modeled as operational for the entire fiscal year. In reality, the start dates of the emergency generation would likely be staggered over a number of months throughout the fiscal year; however, for the purposes of modeling, the emergency generation is modeled as online for the entire fiscal year so that the results can compared directly to the other sensitivity scenarios detailed in this report (i.e., in the other scenarios that model additional solar PV, energy storage, etc., this study considers those additional resources as also online for the entire fiscal year).

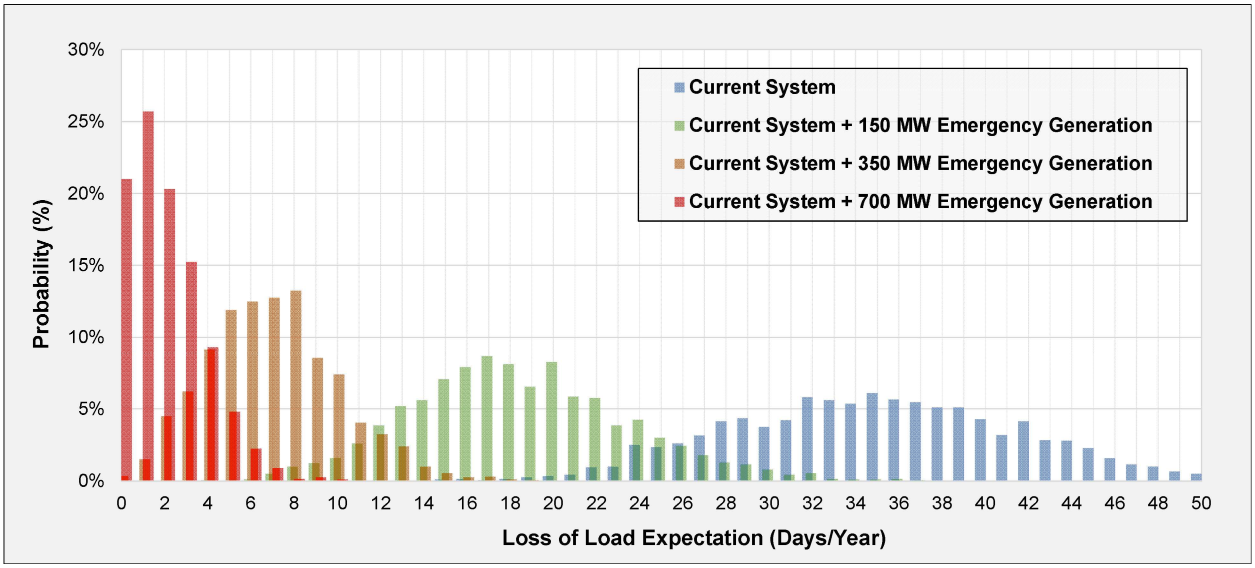
The addition of the incremental emergency generation greatly reduces LOLE and LOLH as compared to the current system scenario. The resource adequacy measures of 1) the current system scenario compared to 2) the current system with the increasing amounts new emergency generation are provided in the table below. As can be seen, the addition of the emergency generation has a significant impact on improving system resource adequacy.

Table A-20: Calculated Resource Adequacy Risk Measures – New Emergency Generation

Scenario	Loss of Load Expectation (LOLE)	Loss of Load Hours (LOLH)
Current System	37.5 Days / Year	194.5 Hours / Year
Current System + 150 MW Emergency Generation	18.5 Days / Year	86.5 Hours / Year
Current System + 350 MW Emergency Generation	7.0 Days / Year	29.4 Hours / Year
Current System + 700 MW Emergency Generation	2.0 Days / Year	8.5 Hours / Year
Industry Benchmark Target	0.1 Days / Year	—

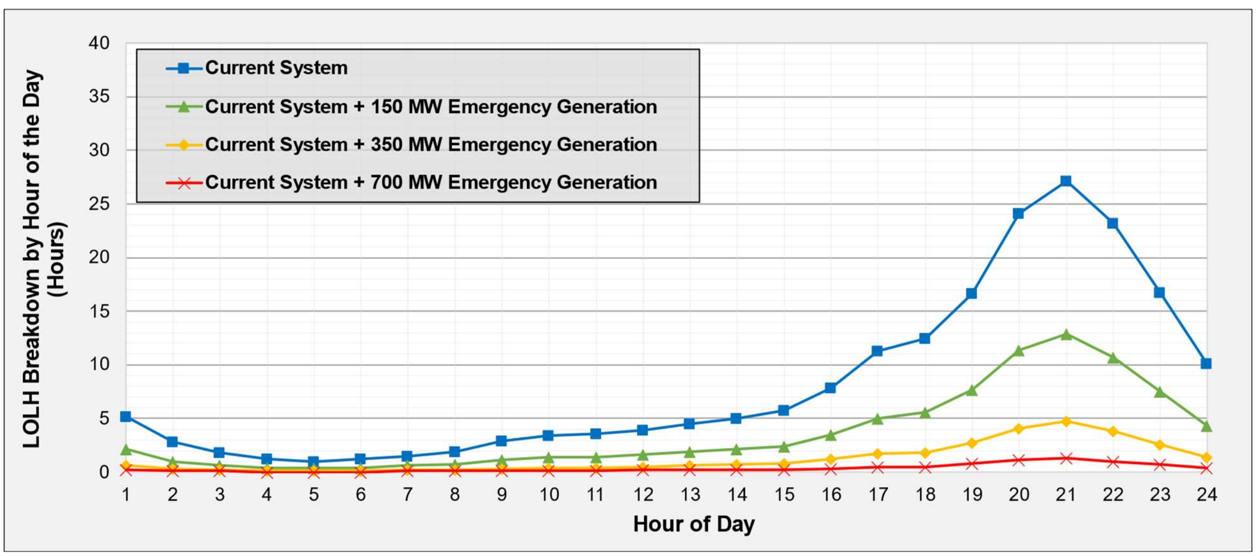
The following figure compares the distribution of LOLE (for the 2,000 simulations performed) between the each of the different scenarios. As can be seen, the addition of the new emergency generation significantly helps improve system LOLE, both shifting the distributions further left (to lower LOLE levels) and reducing the width of the distributions. Note that 20% of simulations (out of the 2,000 performed) have zero LOLE after the 700 MW of emergency generation is added.

Figure A-45: Comparison of Loss of Load Expectation – New Emergency Generation



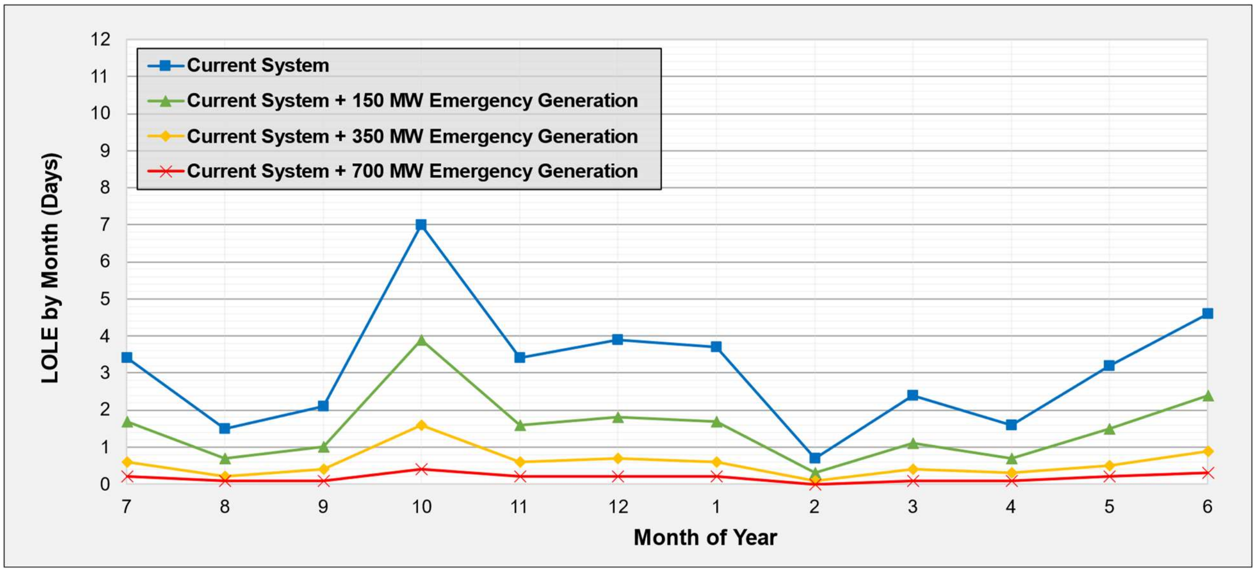
The figure below compares average annual LOLH between 1) the current system scenario and 2) the current system with the various amounts of new emergency generation. As can be observed, the addition of the new emergency generation is able to improve system performance for all hours of the day – which is due to the fact that the emergency generation is dispatchable.

Figure A-46: Comparison of Loss of Load Hours – New Emergency Generation



The figure that follows shows the forecasted LOLE by month after the various MW of emergency generation are online.

Figure A-47: Comparison of Loss of Load Hours by Month – New Emergency Generation



Appendix 18. Sensitivity Analysis – Early Retirement of the AES Coal Power Plant

The AES coal power plant is the single largest generator in the Puerto Rico system, with a nameplate capacity of 454 MW. The early retirement of the AES power plant would equate to around a 10% decrease in Puerto Rico's generating capacity. AES is also a newer unit that was built in 2002 and has exhibited strong performance with an annual forced outage rate of 5%, which is significantly below the average forced outage rate for many of the other power plants on the island. A sensitivity analysis was performed to investigate the resource adequacy impact of the early retirement of AES for all of FY2024.

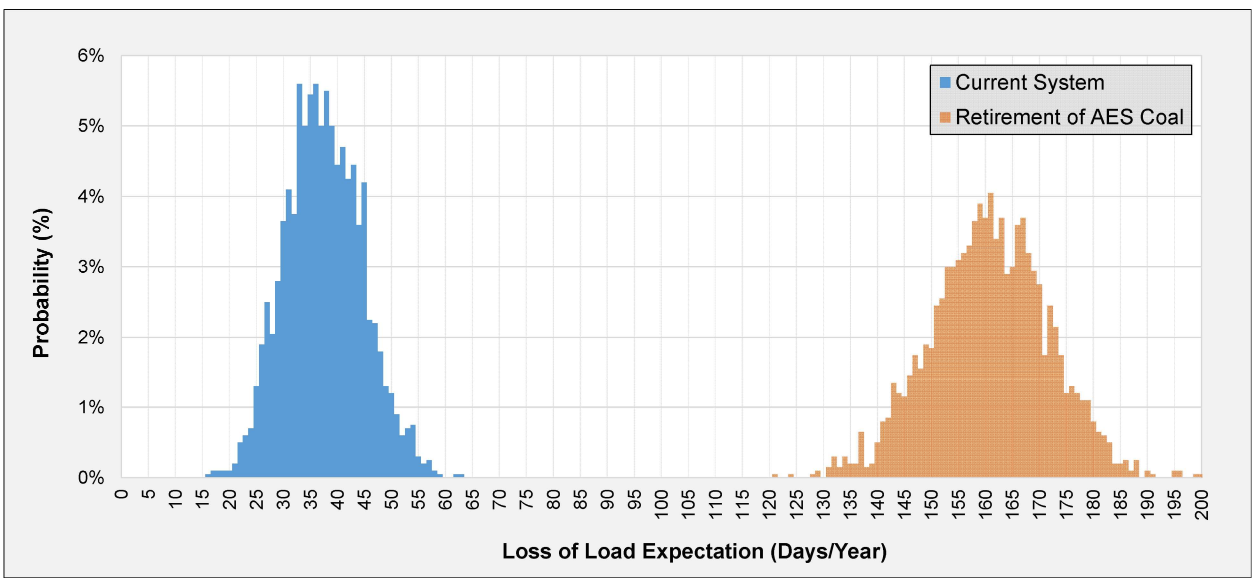
The retirement of this generator (or any other similar-sized generator) without a suitable replacement is substantial from a resource adequacy perspective and results in a significant decline in system resource adequacy. The retirement of AES without a suitable replacement would result in 160.8 days of loss of load, which is almost half the days in a year and 1,600 times the industry target of 0.1 LOLE. The LOLH also increase to 1,193.6 hours, or six times the expected LOLH from the current system simulation. The following table compares the current system scenario to the retirement of AES scenario.

Table A-21: Calculated Resource Adequacy Risk Measures – Retirement of AES Generator

Scenario	Loss of Load Expectation (LOLE)	Loss of Load Hours (LOLH)
Current System	37.5 Days / Year	194.5 Hours / Year
Retirement of AES Coal	160.8 Days / Year	1,193.6 Hours / Year
Industry Benchmark Target	0.1 Days / Year	—

The following figure compares the distribution of LOLE (for the 2,000 simulations performed) between the current system scenario and the scenario where AES is retired for all of FY2024.

Figure A-48: Comparison of Loss of Load Expectation – Retirement of AES Coal Power Plant



Given the poor expected system resource adequacy in the event the AES coal power plant is retired without a suitable replacement, additional sensitivity analysis was performed to investigate a near term option to replace / partially replace AES' retired capacity, as is described below:

- AES is retired for all of FY2024 and replaced by the addition of the Tranche 1 solar PV and BESS projects (845 MW solar PV and 220 MW of solar-paired 4-hr BESS)

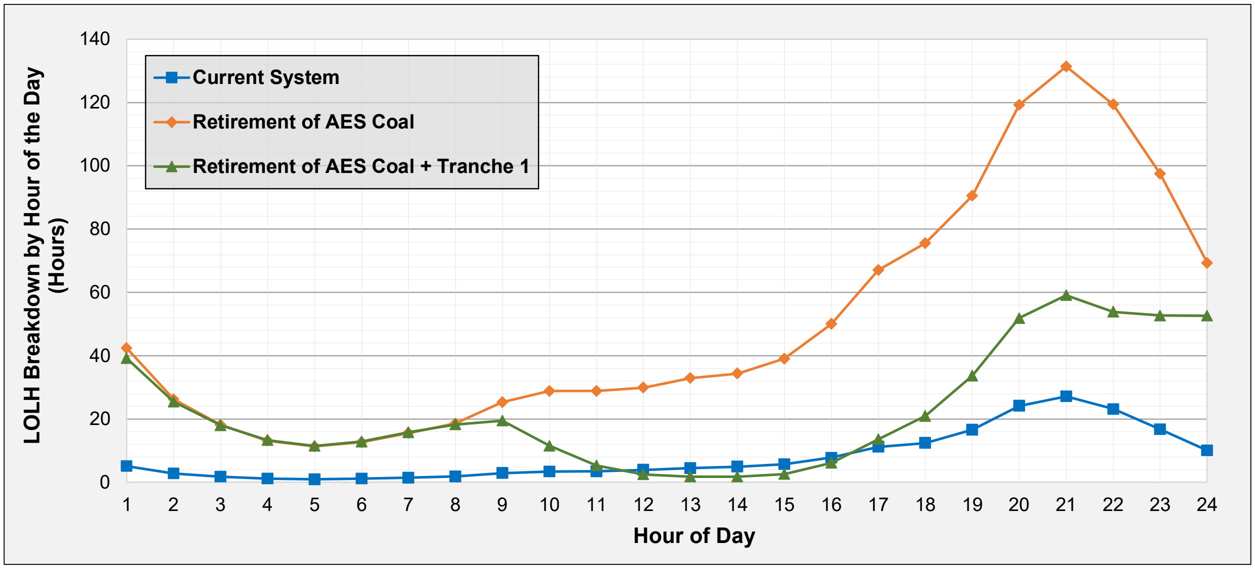
The results are provided in the table below:

Table A-22: Calculated Resource Adequacy Risk Measures – Retirement of AES Generator

Scenario	Loss of Load Expectation (LOLE)	Loss of Load Hours (LOLH)
Current System	37.5 Days / Year	194.5 Hours / Year
Retirement of AES Coal	160.8 Days / Year	1,193.6 Hours / Year
Retirement of AES Coal + Tranche 1 (845 MW Solar PV + 220 MW 4-hr BESS)	90.7 Days / Year	542.6 Hours / Year
Industry Benchmark Target	0.1 Days / Year	—

The following figure compares LOLH for each of the different scenarios analyzed.

Figure A-49: Comparison of Loss of Load Hours by Hour – Retirement of AES Coal Power Plant



As can be seen in the previous figure, the addition of the Tranche 1 solar PV and BESS projects helped reduce LOLH midday and around the evening peak, but these resources alone did not fully compensate for the loss of the AES coal power plant.

Overall, the analysis indicates that the Tranche projects are not a suitable near-term replacement for the AES coal power plant from a purely resource adequacy perspective.

Appendix 19. Sensitivity Analysis – Perfect Capacity Estimated Equivalency

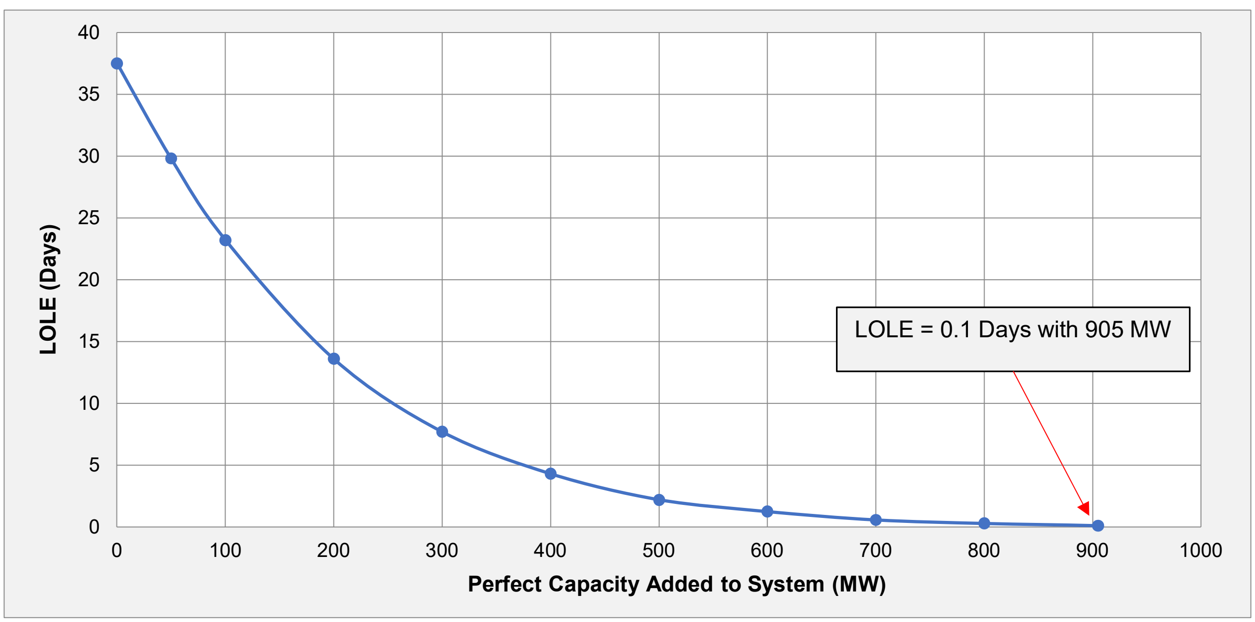
An analysis was performed to determine how much additional 'perfect' capacity[37] would need to be added to the Puerto Rico electrical system to achieve an LOLE target of 0.10 days/year. The analysis was completed by adding various amounts of perfect capacity to the resource adequacy model and iterating the analysis. The analysis was complete once the amount of perfect capacity that resulted in the system LOLE equaling 0.10 days/year was determined. The results of the simulation determined that 905 MW of perfect capacity would result in an LOLE of 0.10 days/year. Results are summarized below.

Table A-23: Calculated Resource Adequacy Risk Measures – Perfect Capacity Addition

Scenario	Loss of Load Expectation (LOLE)	Loss of Load Hours (LOLH)
Current System	37.5 Days / Year	194.5 Hours / Year
Current System + **905 MW** of Perfect Capacity	0.1 Days / Year	0.3 Hours / Year
Industry Benchmark Target	0.1 Days / Year	—

The following figure illustrates the iterative process for how system LOLE falls with incremental amounts of perfect capacity added.

Figure A-50: Loss of Load Expectation With Incremental Amounts of Perfect Capacity



[37] Perfect generation capacity is always fully available. From a modeling perspective, MWs of perfect capacity are equivalent to the same number of MWs as a reduction in hourly system load. Perfect capacity is theoretical in nature and not based on a specific generation technology type; however, if it were derived from intermittent sources, there would need to be sufficient energy storage such that it was fully dispatchable for every hour.

Given that no generation technology can operate as a perfect generator, the actual amount of capacity required for the system to meet a 0.10 days/year LOLE target would be somewhat higher than the 905 MW identified above. Additionally, it varies by generator technology type. The uniqueness of the resource adequacy contributions of different technologies is driven by generator capacity factor, energy availability, maintenance, plant outages, and dispatchability.

Modeling results indicate that in Puerto Rico, 905 MW of perfect capacity is required to obtain the 0.1 days per year industry benchmark LOLE target.

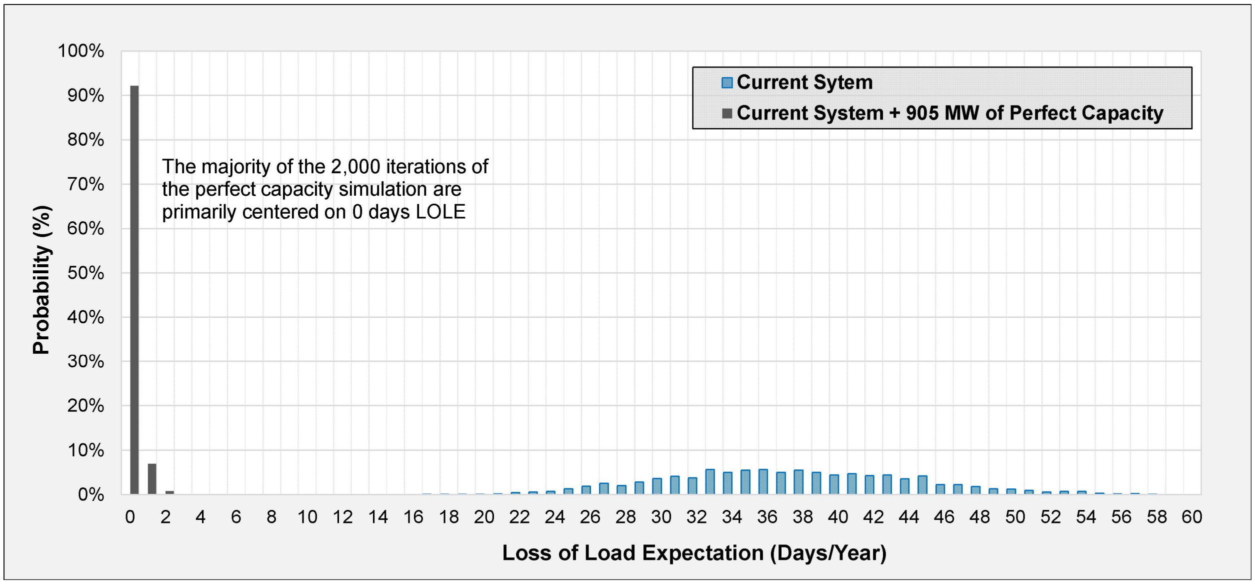
An underlying assumption around perfect capacity is that it operates at a 100% capacity factor. For 905 MW of perfect capacity, this would be equivalent 7,927,800 MWh of annual generation (905 MW multiplied by 8,760 hours in the year). For illustrative purposes, a high-level comparison of technology capacity factors required to achieve 7,927,800 MWh of energy is provided in the following table. Note that even with equivalent annual generation, non-dispatchable generation technologies may still fall short of helping the system achieve a 0.1 days / year LOLE target without storage resources to shift energy to needed time periods. For example, while the table illustrates that 3,935 MW of solar PV is capable of generating 7,927,800 MWh of electricity annually, unless there were a sufficient number of storage resources to shift much of the solar PV-generated electricity to the evening hours and overnight, it would not be possible for 3,935 MW of additional solar PV alone to bring system LOLE to 0.1 days / year.

Table A-24: Capacity Factor Comparison for Various Technologies

Resource	Annual Generation (MWh)	Capacity Factor (%)
905 MW of Perfect Capacity	7,927,800	100
3,935 MW of Solar PV	7,927,800	23
4,114 MW of Wind	7,927,800	22
953 MW of Flexible Capacity	7,927,800	95

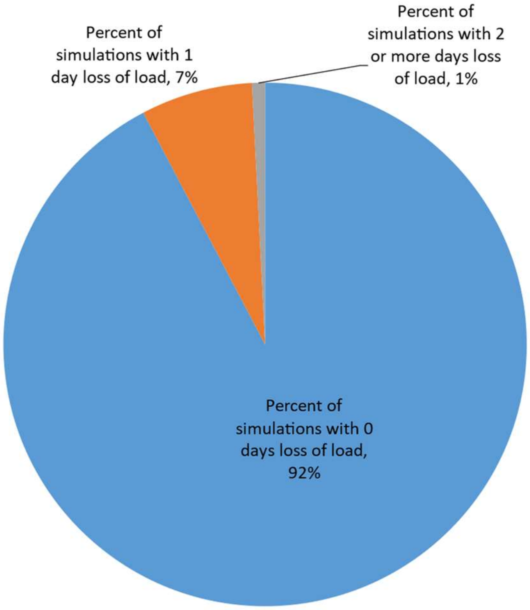
The following figure compares the distribution of LOLE (for the 2,000 simulations performed) between the current system scenario and the scenario where 905 MW of perfect capacity is added. In the figure, the majority of the perfect capacity simulation's distribution is centered at 0 days LOLE. Note that the current system scenario appears much wider than in other figures of this report; however, this is because the y-axis of the figure had to be adjusted to fit the entire perfect capacity distribution.

Figure A-51: Comparison of Loss of Load Expectation – Perfect Capacity Simulation



A breakdown of the LOLE distribution for the perfect capacity scenario can be further visualized in the pie chart that follows.

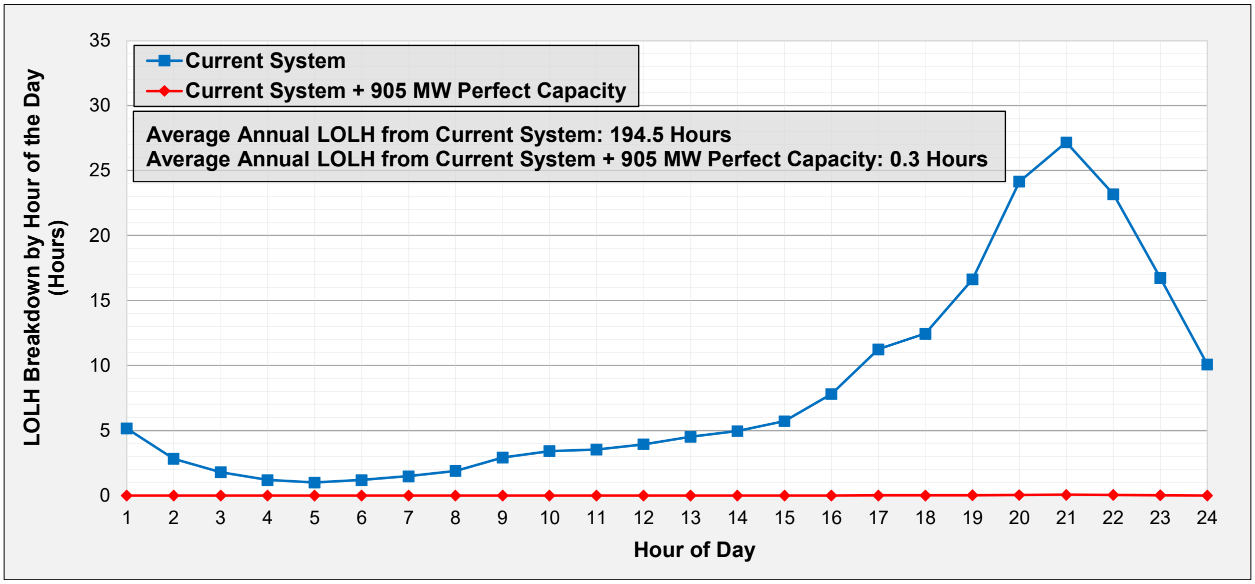
Figure A-52: Loss of Load Expectation Pie Chart – Perfect Capacity Addition



The graph breaks down the annual days of loss of load based on the distribution of the Monte Carlo simulations performed

The following figure provides more detail regarding the results of the analysis, particularly with respect to LOLH on an hourly basis. The figure compares hourly LOLH for the current system scenario to the scenario with the additional 905 MW of perfect capacity. As can be seen, the addition of the 905 MW significantly improves the overall electrical system from the perspective of generation resource adequacy – to a point where LOLH cannot even been observed for the perfect capacity scenario when it is placed on the same figure as the current system scenario.

Figure A-53: Comparison of Loss of Load Hours by Hour – Perfect Capacity



Appendix 20. Sensitivity Analysis – Additional Standalone Solar Results

A sensitivity scenario was evaluated to assess potential resource adequacy contribution of additional solar generation in Puerto Rico. The scenario added 845 MW of solar energy to the current system. The value of 845 MW was chosen because this is the expected amount of solar energy that is projected to be added to Puerto Rico as a result of the PREPA Tranche 1 renewable procurement. Note that this scenario does not include energy storage as it seeks to only investigate the impact of additional solar PV. Both standalone energy storage and energy storage paired with solar PV are investigated in other sensitivity analyses documented in later appendices of this report.

As illustrated in the table below, the 845 MW of solar PV added to the current system decreases LOLE from 37.5 days/year to 35.9 days/year, which is a 4% improvement in LOLE. Solar PV additions to the current system provided a greater resource adequacy contribution toward reducing the LOLH rather than LOLE – the 845 MW of solar PV added to the system decreased the LOLH from 194.5 hours/year to 154.6 hours/year, which is a 21% reduction.

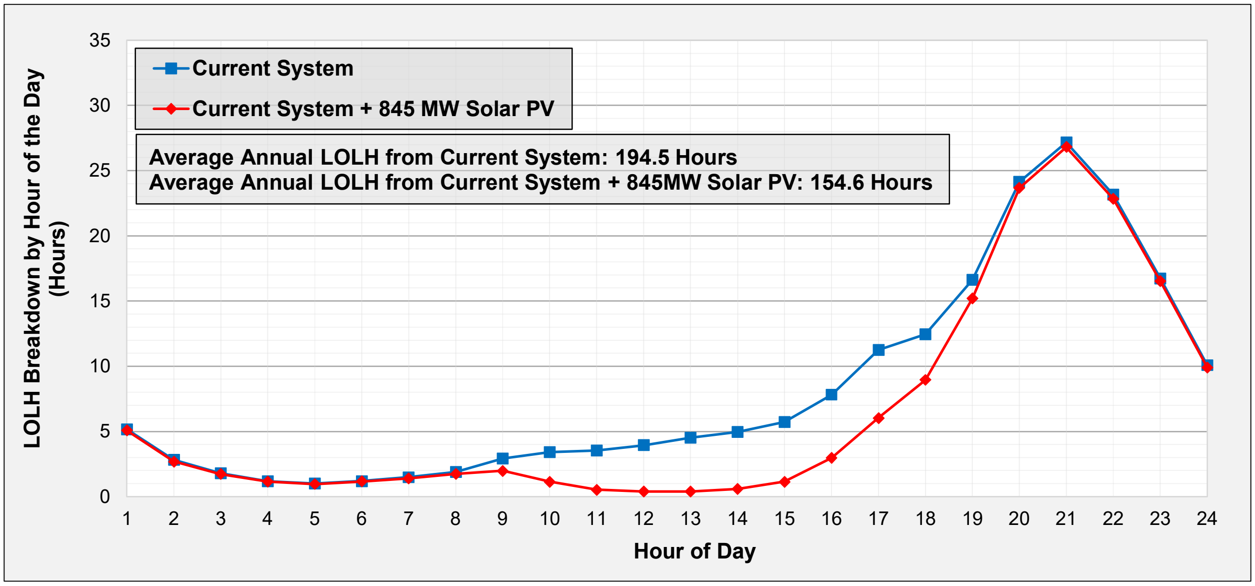
Table A-25: Calculated Resource Adequacy Risk Measures – Solar PV Addition

Scenario	Loss of Load Expectation (LOLE)	Loss of Load Hours (LOLH)
Current System	37.5 Days / Year	194.5 Hours / Year
Current System + 845 MW of Solar PV	35.9 Days / Year	154.6 Hours / Year
Industry Benchmark Target	0.1 Days / Year	—

The difference between the relatively low LOLE improvement versus the more robust improvement in LOLH stems mainly from a combination of when solar PV power plants generate and when the electrical system is at greatest risk for loss of load. During the middle of the day, solar PV can contribute a great deal of MWs towards meeting system load; however, during the evening (after the sun has set), additional solar is not able to contribute towards meeting system load because solar generation will be zero at this time. In Puerto Rico, the risk of loss of load during the middle of the day is pronounced; however, the highest risk period is in the evening because this is when system load is highest. As a result, if there was a generation shortfall event that spanned an entire day (i.e., a forced outage to a large thermal generator), additional solar PV would help to mitigate / minimize potential loss of load during the middle of the day, but the additional solar would not be able to contribute to meeting load in the face of the generation shortfall event in the evening after the sun had set. More specifically, the additional solar PV might help to shorten the length of a loss of load period (i.e., reduce the total LOLH) by helping the system to meet load during the day, but it would not be able to prevent the loss of load event from still occurring in the evening, which means there still would be a day where there was loss of load (hence the small reduction in LOLE).

The following figure compares the timing of the average annual loss of load hours for each hour of the day for the current system versus the additional solar PV case. The figure clearly illustrates that additional solar PV is able to help mitigate LOLH during the middle of the day, but not during the evening.

Figure A-54: Comparison of Loss of Load Hours by Hour – Solar PV Addition



Appendix 21. Sensitivity Analysis – Additional Standalone BESS Results

This sensitivity evaluates the impact of adding standalone BESS to the current system. For this sensitivity, no additional solar PV is added to the current system (a scenario considering both additional solar PV and solar-paired BESS is analyzed in a separate appendix). This sensitivity scenario considers 220 MW of 4-hour duration standalone BESS. Note that this BESS capacity is consistent with what is expected to be added to the island as part of PREPA's renewable Tranche 1 projects.

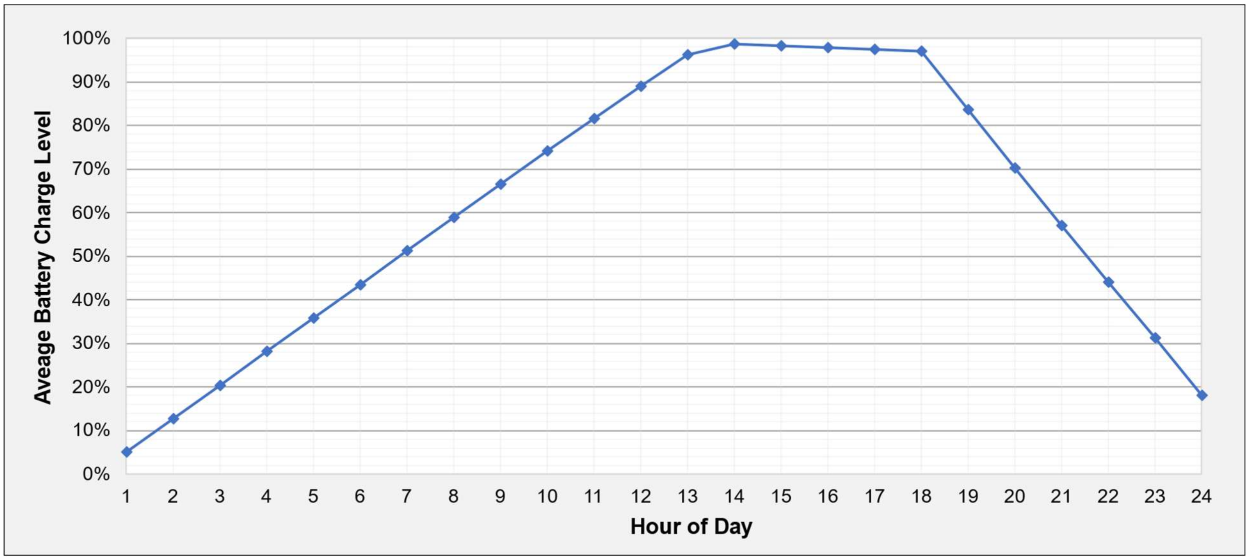
For this scenario, the round-trip efficiency of the BESS is assumed to be 85%. Typical hourly dispatch of the BESS is modeled such that discharge occurs throughout the evening to help meet peak load, with the BESS modeled as being mostly depleted around midnight. Charging of the BESS primarily takes place during the early morning hours until about noon, when system load is lowest.

Whenever there is an emergency situation, defined as a period where system load is greater than total system available capacity, the model forces the BESS resources to inject available energy to meet load demand. If the shortfall in available system capacity is greater than what the BESS is able to inject at that hour, or if the BESS does not have sufficient charge, the BESS resources inject what they are able to in order to minimize the MW shortfall.

In contrast to solar-paired BESS, standalone BESS has the benefit of being able to charge from the grid at any time during the day, capturing surplus energy during times when available capacity is high and energy demand is low (i.e., nighttime in Puerto Rico). Since it can be fully charged earlier in the day than solar-paired BESS, it can be dispatched to help mitigate emergency MW shortfall situations that occur earlier in the day, when a solar-paired BESS might otherwise not yet be fully charged. In contrast, because standalone BESS charges from energy from the generating resources that are operating at that time, if standalone BESS is charging during the early morning, it is primarily charging from thermal generators, not renewable generators. Additionally, if standalone BESS is mostly charged before the sun rises, then it could not be used as a tool to help mitigate potential solar power plant curtailment. We recommend both standalone and solar-paired BESS be considered as potential candidate resources for further analysis in the future IRP process.

The figure below shows the average state of charge by hour of the day for the standalone BESS over all simulations performed. As shown, the BESS is primarily charging overnight between 1 am and noon. On average, start discharging at 6 p.m. to help the system during the evening peak. The typical charging and discharging patterns of the BESS were validated independently via PLEXOS dispatch modeling simulations.

Figure A-55: Standalone BESS Average State of Charge by Hour



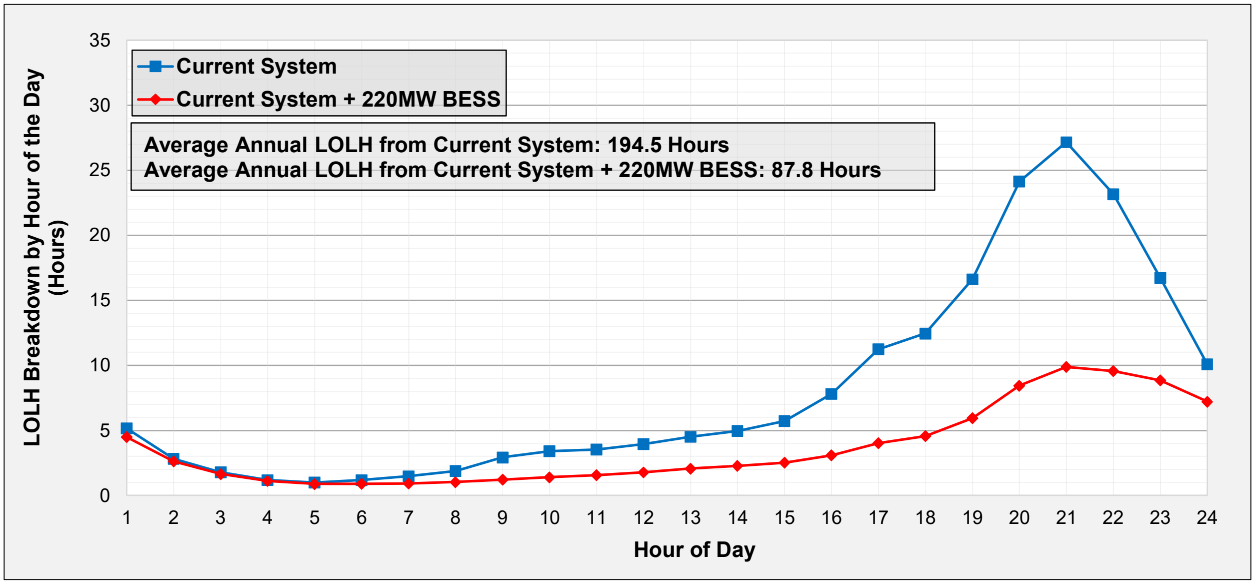
The table below shows the results of this sensitivity case, along with the current system results for comparison. As compared to the current system, the addition of 220 MW of 4-hour duration standalone BESS reduces both LOLE by 59% and LOLH by approximately 55%.

Table A-26: Calculated Resource Adequacy Risk Measures – Standalone BESS Addition

Scenario	Loss of Load Expectation (LOLE)	Loss of Load Hours (LOLH)
Current System	37.5 Days / Year	194.5 Hours / Year
Current System + 220 MW Standalone BESS (4 Hour Duration)	15.4 Days / Year	87.8 Hours / Year
Industry Benchmark Target	0.1 Days / Year	—

The addition of standalone BESS results in improvement to both LOLE and LOLH for a given scenario. This is because standalone BESS can contribute to system capacity nearly all times of the day, with the only limitation being the state of charge. Given that the majority of the observed LOLH in the current system scenario occurred between 6 p.m. and 11 p.m., standalone BESS has a strong positive impact on system resource adequacy due to its ability to support the system at night. The figure that follows shows the average LOLH for all the simulations for the two scenarios (current system and additional BESS). As shown, the standalone BESS help reduce the incidence of LOLH during the day and nighttime hours.

Figure A-56: Comparison of Loss of Load Hours by Hour – Standalone BESS Addition



Appendix 22. Sensitivity Analysis – Additional Solar and Paired BESS Results

This sensitivity evaluates the impact of adding a combination of both solar PV and BESS. In this sensitivity, the BESS is modeled as paired with the solar PV, meaning that it is only allowed to charge from the solar PV generation. The scenario considers a total of 845 MW of solar PV and 220 MW of 4-hour duration BESS. Note that this scenario represents the full addition of new generating resources as planned under PREPA's renewable Tranche 1 projects.[38]

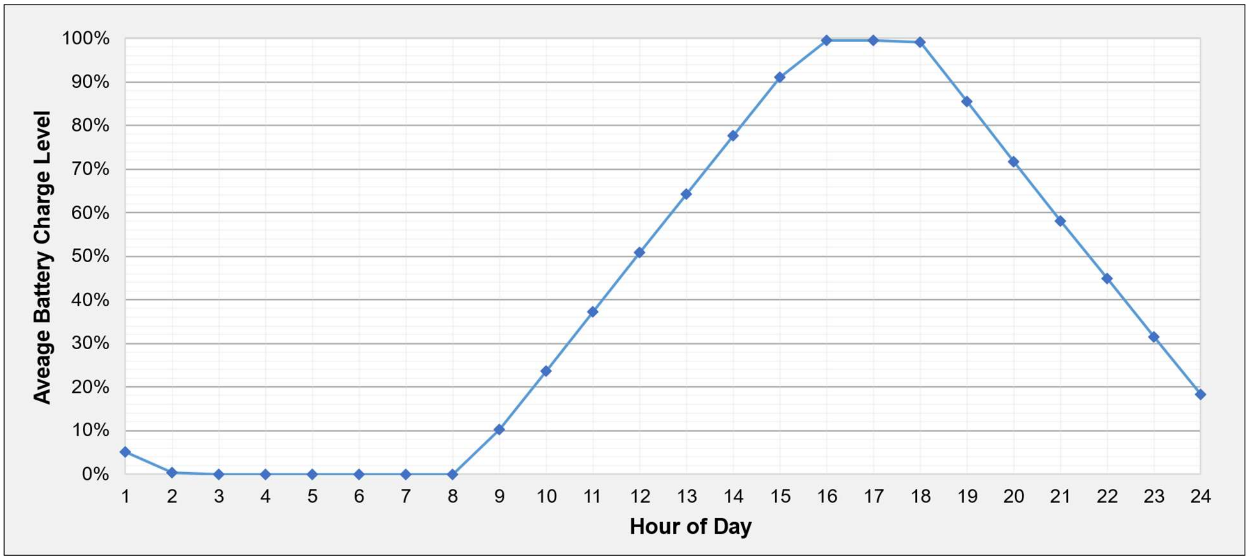
For this scenario, the round-trip efficiency of the BESS is assumed to be 85%. Typical hourly dispatch of the BESS is modeled such that discharge occurs throughout the evening to help meet peak load, with the BESS modeled as being depleted around or shortly after midnight. Charging of the BESS is from the solar PV power plants; thus, charging only occurs during the day.

Whenever there is an emergency situation, defined as a period where load is greater than available capacity, the model forces BESS resources to inject available energy to meet load demand. If the shortfall in available system capacity is greater than what the BESS is able to inject at that hour, or if the BESS does not have sufficient charge, the BESS resources inject what they are able to in order to minimize the MW shortfall. Additionally, any excess solar PV generation above what is needed for BESS charging is assumed to be exported to the grid to serve load.

In contrast to standalone BESS, solar-paired BESS can only charge from energy from the solar PV resources. Because of this, any generation from BESS would be considered renewable generation and would contribute towards Puerto Rico's renewable portfolio standards. The following figure shows the average state of charge by hour of the day for the solar-paired BESS. As shown, the BESS begins to charge as the sun rises and is typically fully charged in the model by the time of evening load peak. BESS then starts discharging at 6 p.m. as the sun sets to support the electrical system during the evening peak. The typical charging and discharging patterns of the BESS were validated independently via PLEXOS dispatch modeling simulations.

[38] Tranche 1 of PREPA's renewable resource procurement process currently accounts for 20 MW of standalone BESS. This sensitivity analysis excludes that small storage amount to understand the impact of solar-paired BESS. Standalone BESS were evaluated in the previous sensitivity analysis.

Figure A-57: Solar-Paired BESS Average State of Charge by Hour



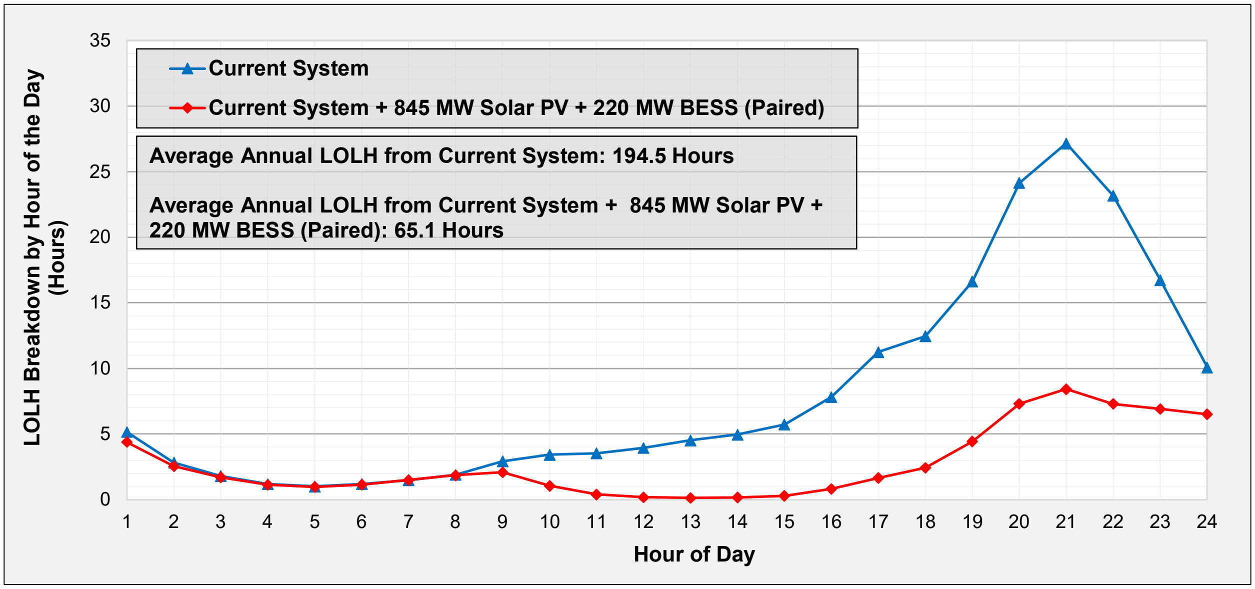
The table below shows the results of the sensitivity scenario, along with the current system results for comparison. As compared to the current system, the addition of 845 MW of solar PV paired with 220 MW of BESS reduces LOLE by 61% and LOLH by 67%. Similar to what was observed in the standalone solar PV-only sensitivity scenario (see Appendix 20), the addition of the solar PV resources has a stronger impact on LOLH over LOLE because the solar PV resources only generate while the sun is shining. However, the addition of the BESS helps to bring down LOLH in the evening hours; thus, LOLE falls much further than in the standalone solar-PV scenario.

Table A-27: Calculated Resource Adequacy Risk Measures – Solar PV + BESS Addition

Scenario	Loss of Load Expectation (LOLE)	Loss of Load Hours (LOLH)
Current System	37.5 Days / Year	194.5 Hours / Year
Current System + 845 MW Solar PV + 220 MW Solar-Paired BESS (4 Hour Duration)	14.5 Days / Year	65.1 Hours / Year
Industry Benchmark Target	0.1 Days / Year	—

The figure that follows shows the average LOLH averaged over the 2,000 simulations performed. As shown, the combination of solar PV and BESS nearly eliminates LOLH during the daytime while the sun is shining and also reduces LOLH during the nighttime as a result of the BESS injection.

Figure A-58: Comparison of Loss of Load Hours by Hour – Solar PV + BESS Addition (Paired)

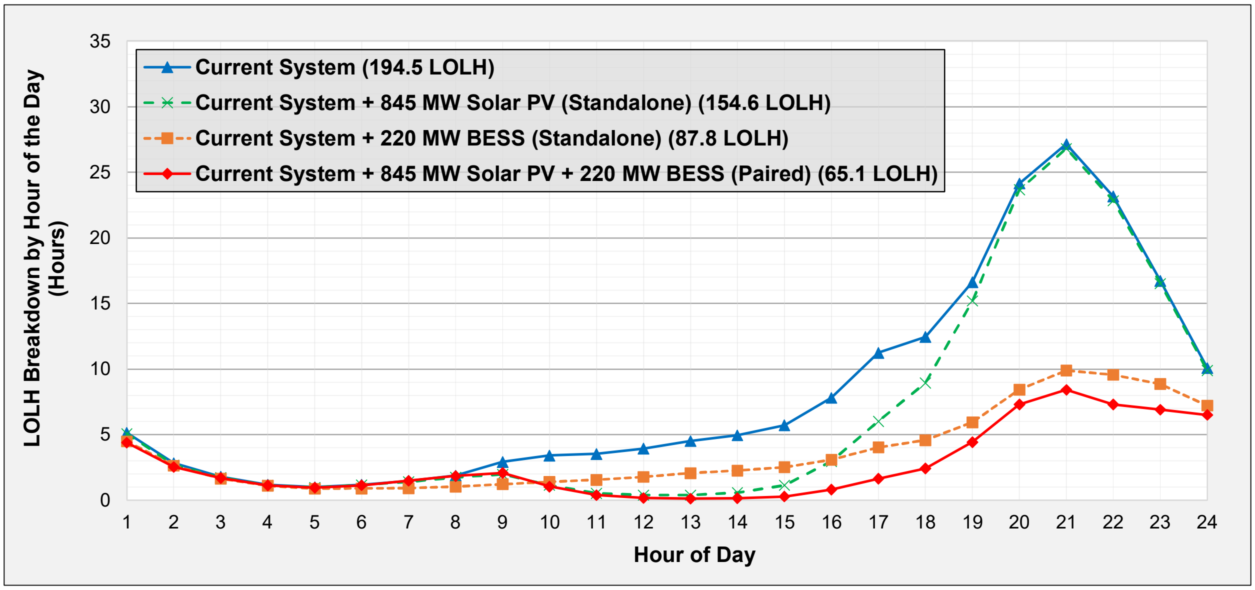


The graph below of average LOLH is provided to compare the following scenarios:

- Current System
- Current System + 845 MW of Standalone Solar PV
- Current System + 220 MW of Standalone BESS (4-hr)
- Current System + 845 MW of Solar PV + 220 MW of BESS (4-hr) (PV and BESS are Paired)

The results illustrate the hourly impact on system resource adequacy of both PV and BESS additions independently, and then also when they are paired together.

Figure A-59: Comparison of Loss of Load Hours by Hour – Comparison of PV and BESS



Appendix 23. Sensitivity Analysis – Additional Flexible Thermal Resources

A sensitivity analysis was performed to investigate the resource adequacy impact of adding additional thermal generators to the system. Some examples of thermal generators include reciprocating engines (RICE), combustion turbines (CTs), and combined cycles (which are typically CTs paired with a secondary steam cycle that helps boost overall power plant efficiency). For a location like Puerto Rico, which is in the process of significantly increasing the amount of renewable generation installed on the island, any new thermal generation should be flexible in that the new generators should have the ability to both ramp and start quickly. Having flexible characteristics would allow new thermal generators to better complement the intermittency of new renewable generation. RICE and aeroderivative CTs (which are derived from turbines installed on aircraft) are flexible resources, and a combined cycle can be designed to be flexible. Today, these types of thermal generators are capable of consuming a variety of different types of fuels, including natural gas, various liquid fuels, biofuels, etc. For this analysis, the specific type of fuel that the flexible thermal generator would consume was not a required input.

Two scenarios that consider new flexible thermal resources were analyzed:

- A new 330 MW combined cycle power plant
- A total of 221 MW of new CTs, split between 11 units of 21 MW each

For both scenarios, the assumed forced outage rate of the different resources considered was 3%. As illustrated in the following table, the 330 MW combined cycle resource added to the current system decreased LOLE from 37.5 days/year to 7.3 days/year, which is an 81% reduction. The 221 MW of new CT resources decreased LOLE from 37.5 days/year to 12.1 days/year, which is a 68% reduction. It is also important to note the additional thermal resources have nearly equal impacts on reducing both LOLE and LOLH – the reason for this is further discussed below.

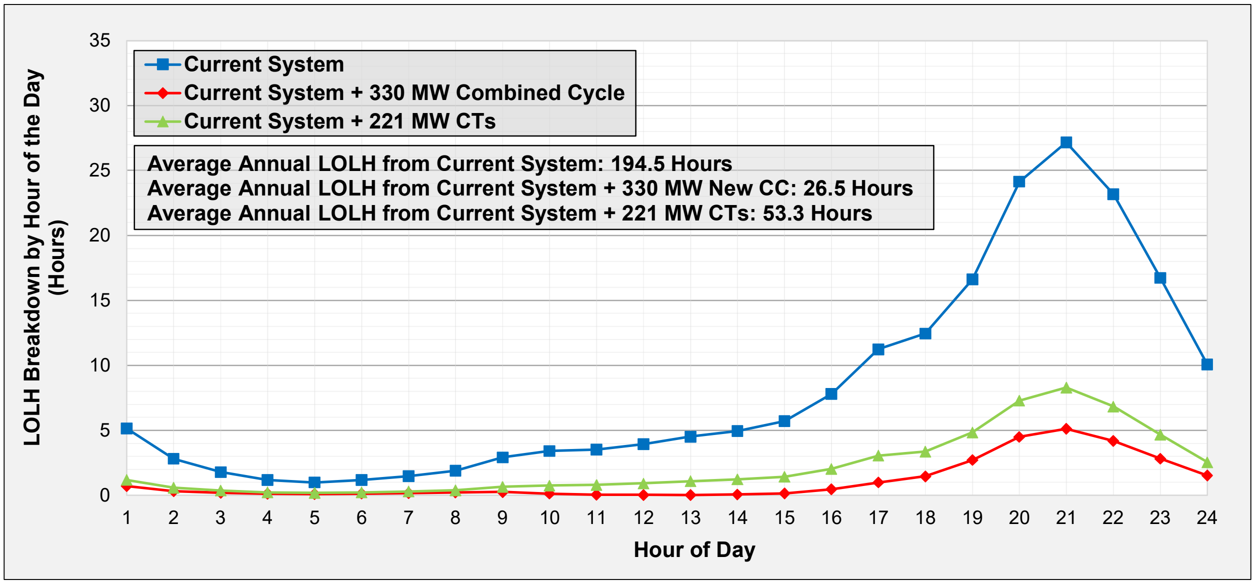
Table A-28: Calculated Resource Adequacy Risk Measures – Flexible CC Thermal Addition

Scenario	Loss of Load Expectation (LOLE)	Loss of Load Hours (LOLH)
Current System	37.5 Days / Year	194.5 Hours / Year
Current System + 330 MW Combined Cycle Thermal Resource	7.3 Days / Year	26.5 Hours / Year
Current System + 221 MW Combustion Turbine Thermal Resources (11 x 21 MW each)	12.1 Days / Year	53.3 Hours / Year
Industry Benchmark Target	0.1 Days / Year	—

The following figure provides the average annual loss of load hours for each hour of the day for the current system compared to both the scenarios with the new combined cycle and CT generators. The figure illustrates an important point: the addition of the flexible thermal resources helps to improve system resource adequacy across all hours, including the evening, when the improvements are needed most.

The reason for this is because these generators are dispatchable, meaning they can be called to generate virtually any time they are needed, provided they are not on forced / planned maintenance and have sufficient fuel available to operate.

Figure A-60: Comparison of Loss of Load Hours by Hour – Flexible Thermal Resources



Appendix 24. Sensitivity Analysis – Additional Distributed Solar PV

A sensitivity scenario was evaluated to assess potential resource adequacy contribution of additional 250 MW of distributed solar PV generation in Puerto Rico. Distributed solar PV is mainly composed of rooftop solar PV installations on residential and commercial rooftops. Compared to utility-scale solar PV, in which site location and PV module array orientation can be nearly perfectly optimized for maximum electricity production, it is difficult to perfectly optimize the location and module orientation of distributed solar PV since it is installed on rooftops, where the orientation of the building / rooftop and any nearby shading may result in less than optimal electricity generation. As such, distributed solar PV will on average have a lower capacity factor than larger utility-scale installations. To account for this, a 15% haircut was applied to the utility-scale solar PV generation profile in order to model the distributed solar PV generation profile. In other words, the modeled distributed rooftop solar PV will generate 15% electricity than an equally sized utility-scale PV system.

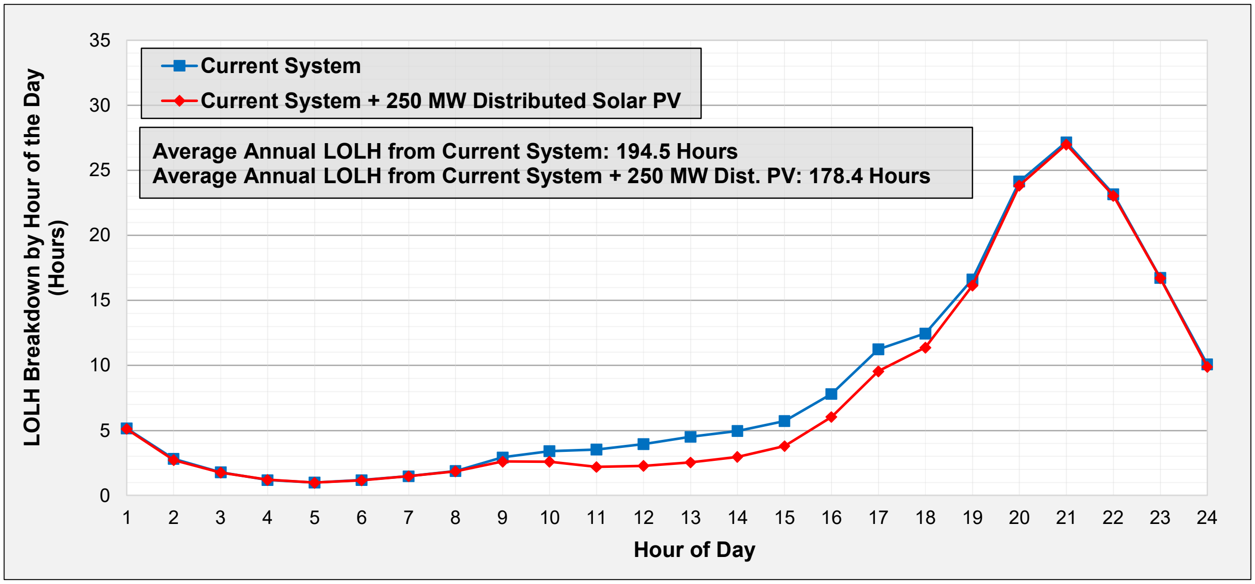
As illustrated in the table below, the 250 MW of distributed solar PV added to the current system decreases LOLE from 37.5 days/year to 36.7 days/year, which is a 2% improvement in LOLE. Similar to utility-scale solar PV scenario analyzed for this report, distributed solar PV additions to the current system provided a greater resource adequacy contribution toward reducing the LOLH than LOLE. The 250 MW of distributed solar PV added to the system decreased the LOLH from 194.5 hours/year to 178.4 hours/year, which is an 8% reduction.

Table A-29: Calculated Resource Adequacy Risk Measures – Distributed Solar PV Addition

Scenario	Loss of Load Expectation (LOLE)	Loss of Load Hours (LOLH)
Current System	37.5 Days / Year	194.5 Hours / Year
Current System + 250 MW of Distributed Solar PV	36.7 Days / Year	178.4 Hours / Year
Industry Benchmark Target	0.1 Days / Year	—

The following figure compares the timing of the average annual loss of load hours for each hour of the day for the current system scenario versus the scenario with the 250 MW of additional distributed solar PV. The figure illustrates that additional distributed solar PV is able to help mitigate LOLH during the middle of the day, but not during the evening.

Figure A-61: Comparison of Loss of Load Hours by Hour – Distributed Solar PV Addition



Appendix 25. Sensitivity Analysis – Additional Demand Response Resources

A sensitivity analysis was performed to investigate the resource adequacy impact of adding demand response (DR) resources to the system. DR resources contribute to improving system resource adequacy by reducing load during times of need. For the purposes of reducing system LOLE and LOLH, load reduction is both an efficient and effective alternative to adding new generators. Note that this analysis did not evaluate the costs or potential economic advantages of DR. A detailed analysis of DR as a demand-side resource would be part of a larger IRP process.

A total of 25 MW of new DR resources are modeled. DR resources function as a short-term reduction in system load when requested by the system operator. Given that a DR resource would not be continuously available for every hour of the year, DR is modeled as being available for a limited number of hours in a rolling 24-hour period. The model treats DR as available to be utilized up to a maximum of 8 hours in a rolling 24-hour period. Note that this assumption is considered as an approximation of DR availability – the actual amount a DR resource would be available would depend on the resource and associated agreement in place with the entity that would be reducing its electrical consumption in response to system operator requests.

In the model, the DR resource is only considered as being available after first considering the available capacity of all other generators in the system. In other words, the model considers DR as the last resort option in circumstances where there would otherwise be a generation capacity shortfall. Modeling DR in this manner allows the model to identify how frequently DR is utilized so that it is not used more than allowed (i.e., more than 8 hours in a rolling 24-hour time period). Actual operation of a DR resource in Puerto Rico might be different than the model depending on the capabilities of the DR resource to reduce electrical consumption, cost of the DR resource, specifics of the agreement, among other items.

The LOLE and LOLH results of the sensitivity analysis are provided in the following table. The addition of DR to the system results in a noteworthy improvement both in terms of LOLE and LOLH, especially considering the relatively small size (25 MW) of the resource.

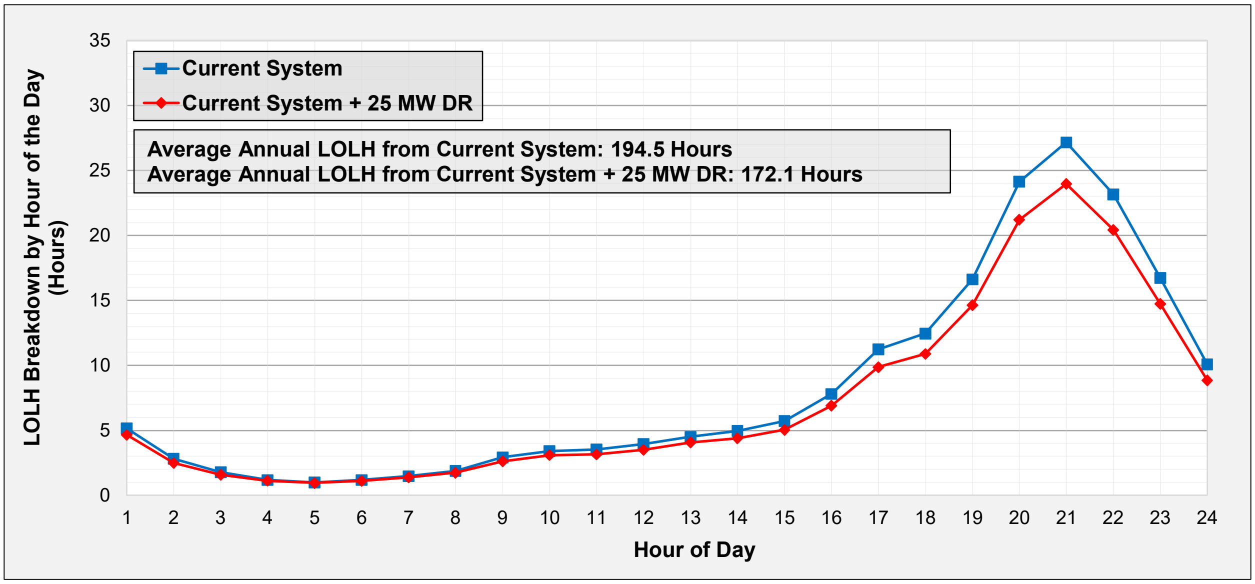
Table A-30: Calculated Resource Adequacy Risk Measures – Demand Response Addition

Scenario	Loss of Load Expectation (LOLE)	Loss of Load Hours (LOLH)
Current System	37.5 Days / Year	194.5 Hours / Year
Current System + 25 MW of DR	33.4 Days / Year	172.1 Hours / Year
Industry Benchmark Target	0.1 Days / Year	—

While there is not enough DR available on the island to achieve the 0.1 days per year industry benchmark LOLE target with DR alone, the LOLE and LOLH reductions seen in the simulations after DR was added are significant. The utilization of the DR resources in the model are primarily during the evening time periods, when system load is highest. Model results illustrate that 25 MW of DR has the potential to reduce LOLE by 4.1 days per year (or 11%), while also reducing LOLH by 22.4 hours per year (or 11%).

The following figure provides the average annual loss of load hours for each hour of the day for the current system. Over 80% of DR utilization takes place between 1 p.m. and midnight, with 46% of DR utilization taking place from 7 p.m. to 10 p.m. It should be noted again that the model only considers DR utilization for the purposes of resource adequacy. Any potential deployment of future DR to reduce generation costs is not captured in the model.

Figure A-62: Comparison of Loss of Load Hours by Hour – Demand Response Addition



Overall, the calculated resource adequacy improvement as a result of adding DR resources make a compelling case for future implementation. DR also has the added benefit of requiring little to no initial investment needed for deployment, especially when compared to the capital cost of constructing traditional generation technologies. DR integration is most effective at improving system resource adequacy in Puerto Rico when it can be deployed during peak hours. To successfully implement DR, coordinated programs would be required to ensure entities are both willing and able to reduce electrical consumption during these times. For this reason, the total amount of available DR that could be successfully implemented is limited. This analysis examines the addition of 25 MW of DR in Puerto Rico, based on an initial estimation of potential opportunities; however, greater than 25 MW could potentially be available if there were sufficient economic incentives.

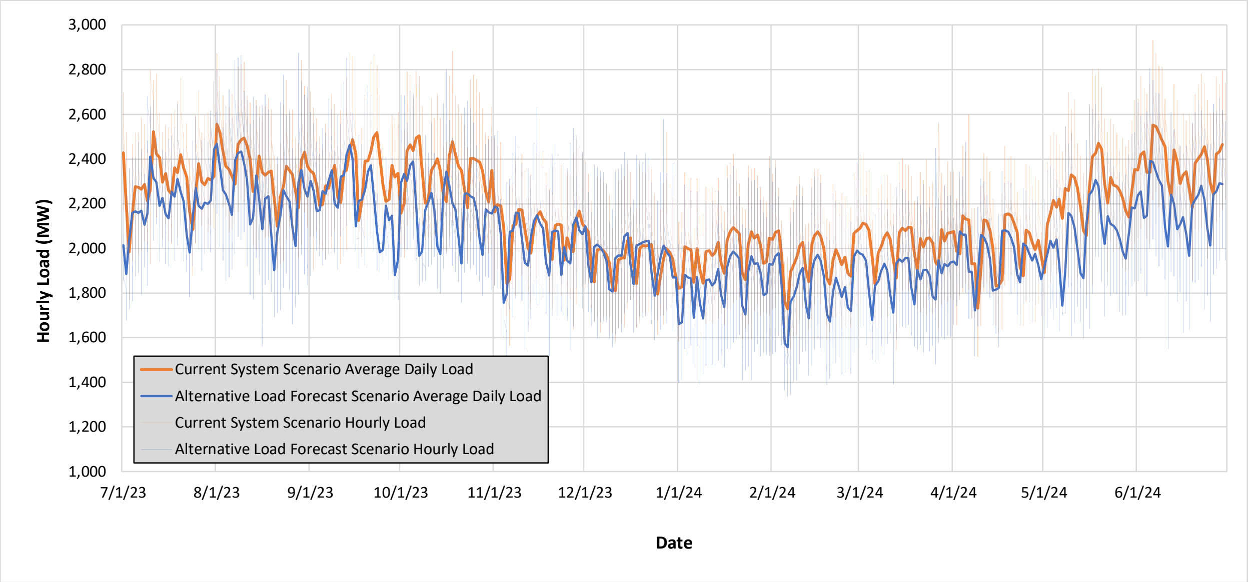
Appendix 26. Sensitivity Analysis – Load Sensitivity

The electrical demand, also referred to as load, is an important element in resource adequacy evaluations, specifically because system generators must be able to meet the electrical demand for every hour. The Puerto Rico electrical load profile considered for the resource adequacy calculations described in this report is equal to the actual metered load values from 2022, with various adjustments to correct for times when metered data was unavailable or reflected abnormal operating conditions – namely the time period during and in the immediate aftermath of Hurricane Fiona. Adjustments were made to the 2022 load data using the historical load data from 2021.

A sensitivity analysis investigating an alternative FY2024 load forecast was performed. The alternative load forecast for FY2024 is based on estimates of expected weather, economic activity, and other macro-economic factors. The macro-economic factors are consistent with projections utilized for the Puerto Rico's fiscal planning process for FY2024. Demand for the alternative forecast is based on average historical temperatures – higher-than-average temperatures would be expected to lead to higher peak demand.

The following figure plots the load profiles for both the current system scenario and the alternative load forecast scenario. In general, the current system scenario load forecast is higher than the alternative load forecast.

Figure A-63: Load Profile Comparison



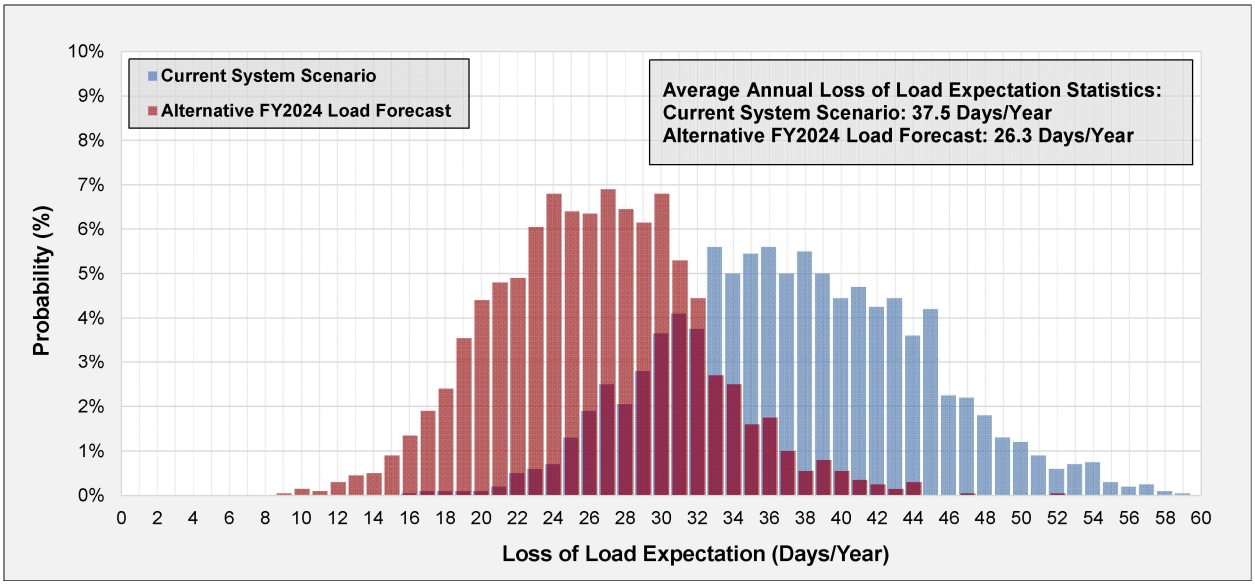
The LOLE and LOLH results of the sensitivity analysis are provided in the following table. Due to the lower load associated with the alternative load forecast, both LOLE and LOLH are lower for that scenario.

Table A-31: Calculated Resource Adequacy Risk Measures – FY2024 Load Forecast

Scenario	Loss of Load Expectation (LOLE)	Loss of Load Hours (LOLH)
Current System (Base Case)	37.5	194.5
Alternative FY2024 Load Forecast	26.3	119.2
Industry Benchmark Target	0.1 Days / Year	—

The following figure presents the LOLE distribution for the two scenarios.

Figure A-64: Loss of Load Expectation Probability Chart – Alternative Load Forecast

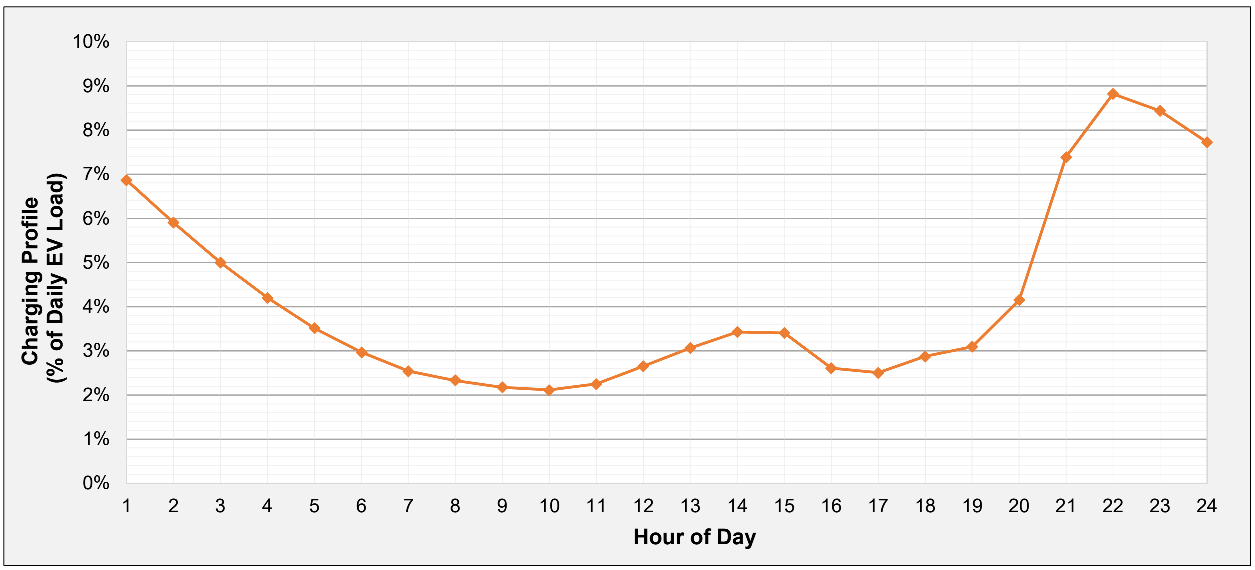


Appendix 27. Sensitivity Analysis – Addition of Electric Vehicle Load

This scenario examines the impact on system reliability of increasing the level of electric vehicle (EV) penetration in Puerto Rico. At present, there are over approximately 2,500 EVs in Puerto Rico.[39] This sensitivity analysis investigates the impact to system resource adequacy as a result of the electrical demand increase from an additional 1,500, 3,000, and 6,000 EVs (on top of what is already operating in Puerto Rico).

For this analysis, each individual EV is assumed to drive 10,000 miles per year, have an average efficiency of 0.33 kWh per mile[40], and an average charging efficiency of 90%. The daily charging profile assumed for this analysis is shown below. The profile was developed based on information in the *Electric Vehicle Infrastructure Projection Tool (EVI-Pro) Lite* tool by the U.S. Department of Energy[41] Most of the charging is assumed to occur around or after peak as people arrive home to plug in their cars, and this tapers off overnight. There is also some midday charging assumed.

Figure A-65: Electric Vehicle Daily Charging Profile



[39] https://www.theweeklyjournal.com/business/insufficient-ev-recharging-infrastructure-in-puerto-rico/article_b3bced94-e377-11ec-a58c-0724f97ee8b1.html
[40] https://www.forbes.com/wheels/advice/ev-charging-kilowatts/
[41] https://afdc.energy.gov/evi-pro-lite

The LOLE and LOLH results of the EV scenario analysis are provided in the following table.

Table A-32: Calculated Resource Adequacy Risk Measures – Electric Vehicle Additions

Scenario	Loss of Load Expectation (LOLE)	Loss of Load Hours (LOLH)
Current System	37.5 Days / Year	194.5 Hours / Year
Additional 1,500 EVs	37.6 Days / Year	195.7 Hours / Year
Additional 3,000 EVs	37.7 Days / Year	194.8 Hours / Year
Additional 6,000 EVs	38.2 Days / Year	198.0 Hours / Year
Industry Benchmark Target	0.1 Days / Year	—

The addition of up to 6,000 EVs had a small impact on the system and increased LOLE by less than a day. It is important to note that total automobile sales in Puerto Rico were over 90,000 cars in 2022 alone[42]. As a result, how best to meet the electrical load from future EVs will be an important planning consideration moving forward since EVs are likely to continue to make up a growing percentage of automobiles sold in Puerto Rico.

[42] https://www.ceicdata.com/en/indicator/puerto-rico/motor-vehicle-sales-passenger-cars

Appendix 28. Effective Load Carrying Capability – Introduction

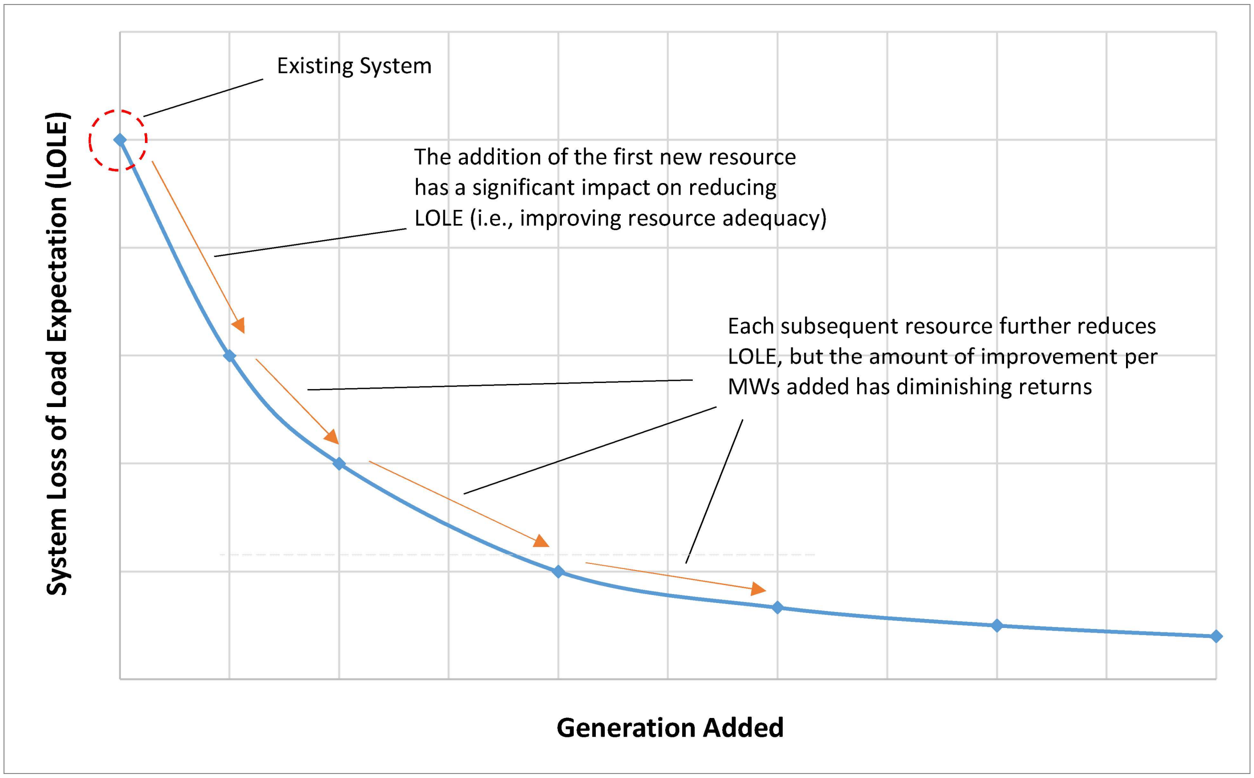
The technical characteristics of different generators can result in them providing varying levels of contributions towards resource adequacy. To effectively evaluate different generating technologies and their contributions towards improving system resource adequacy, a concept called the Effective Load Carrying Capacity (ELCC) of a generator is used. In simple terms, the ELCC of a generator reflects how much the generator’s nameplate capacity is able to contribute towards system resource adequacy. As a single measure, the ELCC allows for quick comparison of resource adequacy contributions of different types of generators. The use of ELCC as a measure to quantify a generator’s contributions towards resource adequacy has become commonplace in the energy industry with the growth in renewable generators such as solar PV, wind, and other similar generation technologies, since the variable generation profiles of these generators makes it a more complex process to quantify the contributions of these generators towards serving system load.

The ELCC of a generator can vary based on a number of variables, including the dispatchability characteristics of the generator. For example, if generation were needed to meet load in the evening, a standalone solar power plant would have a lower overall ELCC than a solar power plant paired with an energy storage system. This is due simply to the fact that the standalone solar power plant would not be capable of generating much electricity in the evening (since the sun would have nearly set at this time), while the storage system paired to the other solar power plant likely could generate electricity in the evening (provided the storage is sufficiently charged). ELCC will vary from one planning region to another because load characteristics change from region to region.

ELCC is typically expressed as a percentage of what could be provided by a “perfect generator”, or a generator that would be available to dispatch every hour of the day, all days of the year. For example, a 100-MW solar generator with an ELCC of 25% would help improve system resource adequacy by an equal amount as a 25 MW perfect generator. An equivalent way to view ELCC is to consider how much system load could be increased with the additional generator such that the system resource adequacy level (LOLE) prior to adding the generator would be equivalent to the resource adequacy level after adding the generator. For example, consider a system with an LOLE equal to 0.10 days/year. A 100 MW solar power plant is added to the system, resulting in the system LOLE to drop to 0.09 days/year. It was then observed that if load were increased by 25 MW, the system LOLE increased back up to 0.10 days/year. In this case, the ELCC of the solar power plant would be equal to 25% (25 MW load increase / 100 MW solar capacity).

It is important to note that the ELCC is a measure of marginal system impact, or the incremental contribution towards resource adequacy. The composition of the existing generation fleet of an electrical system at the specific time the new generator is added has an impact on the new generator’s ELCC. For example, consider the 100 MW solar power plant described above with an ELCC equal to 25% is added to a system. Then, if a second 100 MW is added to the system, the ELCC of the second 100 MW would likely to be less than 25%. The reason for this is because the contributions of additional similar generators towards improving system resource adequacy have diminishing returns. This is illustrated in the following figure, where each dot to the right of the existing system represents additional generators have been added. In the figure, the ELCC of the first new generator would be higher than subsequent generators of similar technology since the amount of LOLE improvement per MW’s added reduces with each subsequent addition.

Figure A-66: Marginal ELCC Illustration



Given that there are costs associated with adding new generators, it is important for system planners to assess the appropriate balance between the desired system LOLE target and system cost, especially since the benefits associated with additional returns diminishes with each additional MW added.

The performance of electric generators in Puerto Rico is currently very poor; thus, there often is not sufficient generation to meet load. As a result, additional MWs of generation in Puerto Rico would result in significant benefits to overall system resource adequacy – especially resources that are able to generate during the evening hours, when system load is highest. Additionally, improvements / modifications to the existing generators in Puerto Rico that improves the generators' reliability would also help improve system resource adequacy. Improving the resource adequacy of the existing generators would increase the ELCC of those generators.

Appendix 29. Effective Load Carrying Capability – Calculation Methodology

ELCC for a generating resource provides the resource adequacy improvement contribution of that resource to the system. Specifically, the ELCC of a generating resource is determined by identifying the size of a perfect capacity generator that yields the same resource adequacy improvement as is achieved with the addition of the resource in study.

The resource adequacy benefit (ELCC) of a generating resource is calculated by first adding the new generator to the study system and noting the improvement to system resource adequacy. Next, a "perfect generator", which is defined as a generator with capacity that is available 100% of the year, is added to the original study system, sized such that the same resource adequacy improvement is achieved. The ELCC is the perfect generator size divided by the new generator size. The following figure provides a step-by-step example of the calculation.

Figure A-67: ELCC Example Calculation

Current System + X MWs = New System A

$LOLE_{Current\ System}$ = 0.15 days/year, $LOLE_{New\ System\ A}$ = 0.10 days/year

The resource "X" above represents a new generator's nameplate capacity.
For example, X might represent 100 MW nameplate for a solar project.

Current System + Z MWs = New System B

$LOLE_{Current\ System}$ = 0.15 days/year, $LOLE_{New\ System\ B}$ = 0.10 days/year

The resource "Z" above represents a new perfect generator.
For example, Z might represent a 30 MW perfect generator.

Z/X = ELCC %

The ELCC is equal to the capacity of the perfect generator divided by the nameplate capacity of the new generator. In this example, the ELCC of the solar project would be 30%, as the 100 MW solar generator would contribute an equal amount to system reliability as a 30 MW perfect generator.

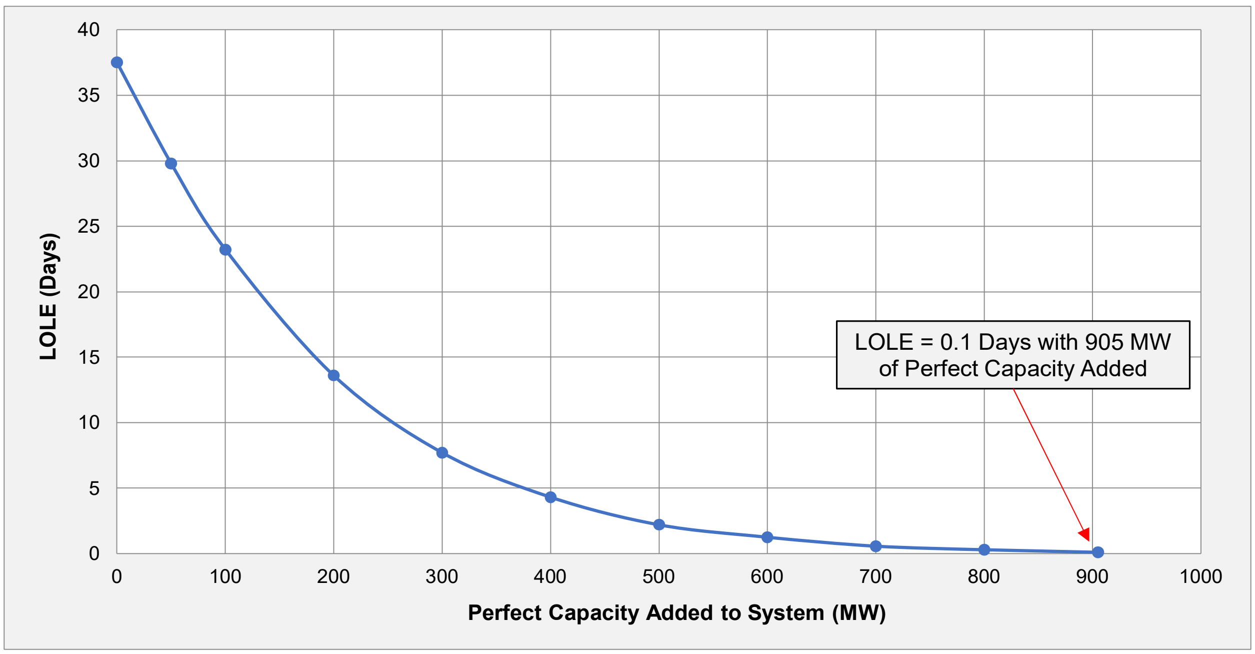
Understanding the varying ELCC values of technologies can assist resource planners in resource adequacy decision-making. The ELCC value for a given technology must be calculated each time a generator is added to the system, since it will change with each additional generating resource.

Appendix 30. Effective Load Carrying Capability – Calculations

ELCC calculations were performed on the current system scenario by adding incremental amounts of standalone solar PV, standalone BESS, or solar PV paired with BESS to the system to determine the impact of these new resources on system resource adequacy. These calculations were done using the PRAS model.[43]

Since ELCC calculations are rooted in determining the resource's perfect capacity equivalent that yields the same LOLE level, the following figure is provided to illustrate system LOLE as a function of perfect capacity added. As the standalone solar PV, standalone BESS, and solar PV paired with BESS resources were added to the system and the associated overall system LOLE was calculated, the following figure provides a guide to what equivalent amount of perfect capacity corresponds to the calculated LOLE.

Figure A-68: Loss of Load Expectation With Incremental Amounts of Perfect Capacity



43 Comprehensive ELCC studies will often run a stochastic analysis using 1) Monte Carlo simulation of forced outage draws 2) multiple weather years of renewable generation data and 3) multiple load forecast scenarios. These can often result in many thousands of individual system simulations that often require supercomputing capabilities and require long lead times. This study uses the Monte Carlo simulation of forced outage draws along with a single deterministic normalized solar profile and a single deterministic annual load forecast (based on actual hourly 2022 metered load). The use of the deterministic inputs in this analysis is unlikely to have a significant impact on the ELCC values calculated; however, future iterations of this analysis should consider a stochastic approach across all critical variables to provide a more robust calculation method. Because of this, the solar PV hourly contribution is set at the average (50th percentile) historical generation values for the purposes of the ELCC calculations (rather than the 90th percentile).

Standalone Solar PV

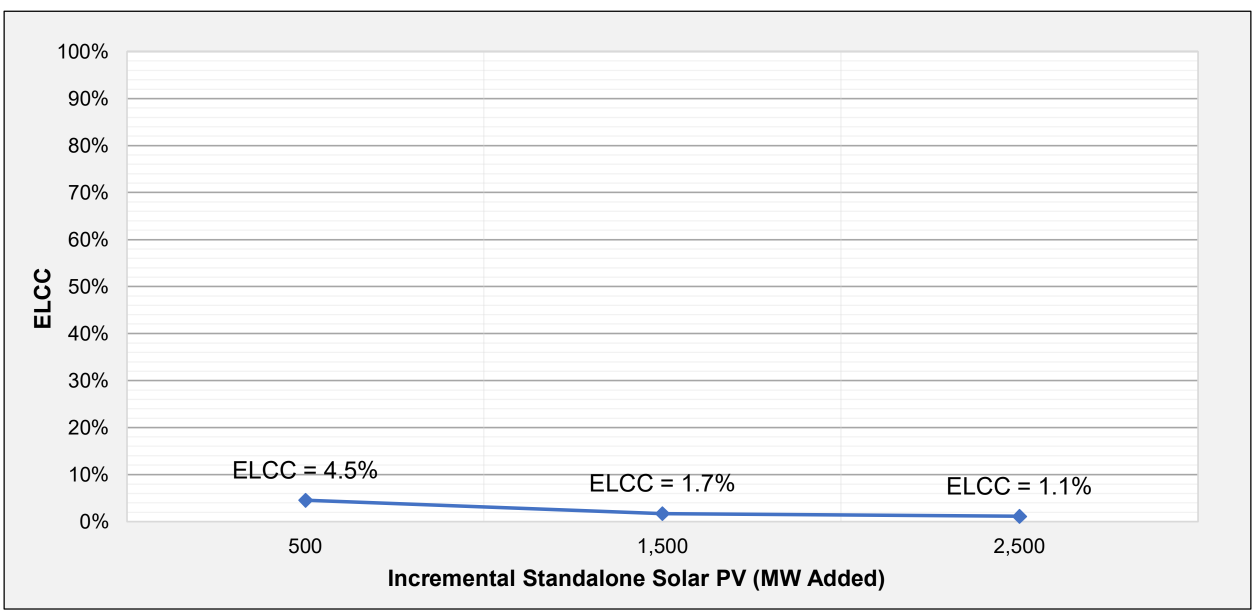
Table A-33 and Figure A-69 as follows illustrates a few important concepts for standalone solar PV and its related ELCC for the Puerto Rico system. The addition of increasing amounts of solar PV results in very little improvement in LOLE, and the small improvement levels off rapidly with additional solar PV. The ELCC for standalone solar PV was calculated at under 5%. This indicates that even large amounts of incremental standalone solar PV will likely not improve system resource adequacy.

As mentioned previously, the low LOLE improvement associated with adding standalone solar PV to the system is a function of when solar PV power plants generate and when the electrical system is at greatest risk for loss of load. During the middle of the day, solar PV can contribute substantially towards meeting system load; however, during the evening (after the sun has set), additional solar PV is not able to contribute towards meeting system load because solar PV generation will be zero at this time. In Puerto Rico, the risk of loss of load during the middle of the day is pronounced; however, the highest risk period is in the evening (after the sun has set) because this is when system load is highest. As a result, if there was a generation shortfall event that spanned an entire day (i.e., a forced outage to a large thermal generator), additional solar PV would help to mitigate potential loss of load risk during the middle of the day, but the electrical system would still be challenged to meet load in the face of the generation shortfall event in the evening after the sun had set, regardless how much solar PV was added.

Table A-33: Calculated ELCC Metrics – Standalone Solar PV

Scenario	Perfect Capacity Equivalent MW	ELCC (%)
Additional 500 MW Solar PV	23	4.5%
Additional 1,500 MW Solar PV	26	1.7%
Additional 2,500 MW Solar PV	28	1.1%

Figure A-69: Standalone Solar PV ELCC



Standalone Energy Storage (BESS)

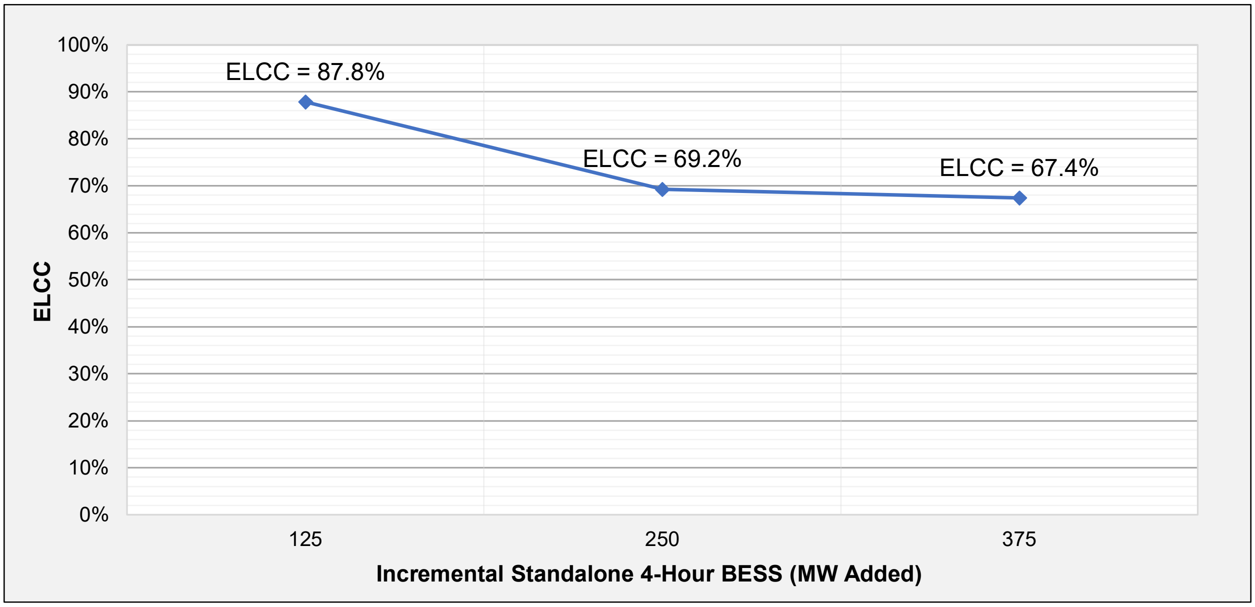
Table A-34 and Figure A-70 illustrate the perfect capacity equivalent and associated ELCC of additional standalone 4-hour duration BESS resources. As compared to the addition of standalone solar PV, the addition of increasing amounts of BESS results in a substantial improvement in LOLE; however, this improvement does gradually reduce over time, illustrating the decreasing marginal ELCC of adding more resources (see Appendix 28 for further discussion). The ELCC for the first 125 MW of BESS is very high at nearly 90% and tripling this amount of BESS capacity to 375 MW still provides an ELCC of almost 70%. The reason for the high ELCC values is because BESS can discharge at all hours of the day, including during the evening when system load is highest (which is the time of the day when the risk of load shed is highest), so long as the BESS resources are appropriately charged.

One should expect the ELCC of standalone storage to be slightly less than that of a thermal resource (i.e., new CT, RICE, etc.) because while both BESS and thermal resources are dispatchable, BESS is an energy-limited resource, meaning it needs to be sufficiently charged in order to inject energy during times of need.

Table A-34: Calculated ELCC Metrics – Standalone BESS

Scenario	Perfect Capacity Equivalent MW	ELCC (%)
Additional 125 MW BESS	110	88%
Additional 250 MW BESS	173	69%
Additional 375 MW BESS	253	67%

Figure A-70: Standalone BESS ELCC



Paired Solar PV and Energy Storage (BESS)

Further sensitivities were performed to investigate the system benefit towards resource adequacy from adding various ratios of paired solar PV and BESS. The simulations assume 4-hour duration BESS resources that can only charge from the additional solar PV resources. The results are shown in the table below. As can be seen, the perfect capacity equivalent of adding the paired solar PV and BESS resources is both high and comparable to the perfect capacity equivalent of adding standalone BESS alone. Maintaining the same level of BESS and increasing the solar PV capacity did little to impact LOLE. The reason for this is twofold: 1) there is already a sufficient amount of solar PV to fully charge the BESS resources in the model for both investigated solar PV levels, and 2) the incremental benefit towards system resource adequacy for adding additional solar PV alone is small (see the discussion above pertaining to the addition of the standalone solar PV).

Table A-35: Calculated Equivalent Perfect Capacity – Paired Solar PV and BESS

Scenario	Perfect Capacity Equivalent MW
500 MW Solar PV + 125 MW BESS	124
1,500 MW Solar PV + 125 MW BESS	127
500 MW Solar PV + 375 MW BESS	293
1,500 MW Solar PV + 375 MW BESS	300

One point to note is that summing the standalone solar PV perfect capacity equivalent and the standalone BESS perfect capacity equivalent is greater than the perfect capacity equivalent of the respective paired resources. The reason for this is because the solar PV-paired BESS resources are more energy limited than the standalone BESS resources – since the paired BESS resources can only charge while the sun is up from the solar PV resources, while the standalone BESS resources can charge virtually anytime, provided the system has excess capacity available.

Appendix 31. Forecasted System Dispatch and Generator Cycling

Prior analysis related to the integration of solar PV plus paired energy storage resources has been performed to investigate the impact on overall system generator dispatch. The analysis utilized the PLEXOS production cost simulation tool and simulated the dispatch of Puerto Rico's generators both with and without the Tranche 1 solar PV and BESS projects.

The following figures compare 1) an annual dispatch simulation of the current system to 2) a dispatch annual simulation of the current system with the Tranche 1 renewable and storage projects operating (totaling 845 MW of solar PV and 220 MW of 4-hour energy storage). The figures compare average hourly dispatch of Puerto Rico's generators, averaged over each day of the simulated year. Generation is broken down by fuel type. For example, generation from the power plants in Puerto Rico that consume natural gas (EcoElectrica, Costa Sur Units 5 & 6, and San Juan Units 5 & 6) are represented in blue. The average hourly expected unserved energy is shown in the red hatched shading.

Figure A-71: Average Generator Dispatch in the Current System

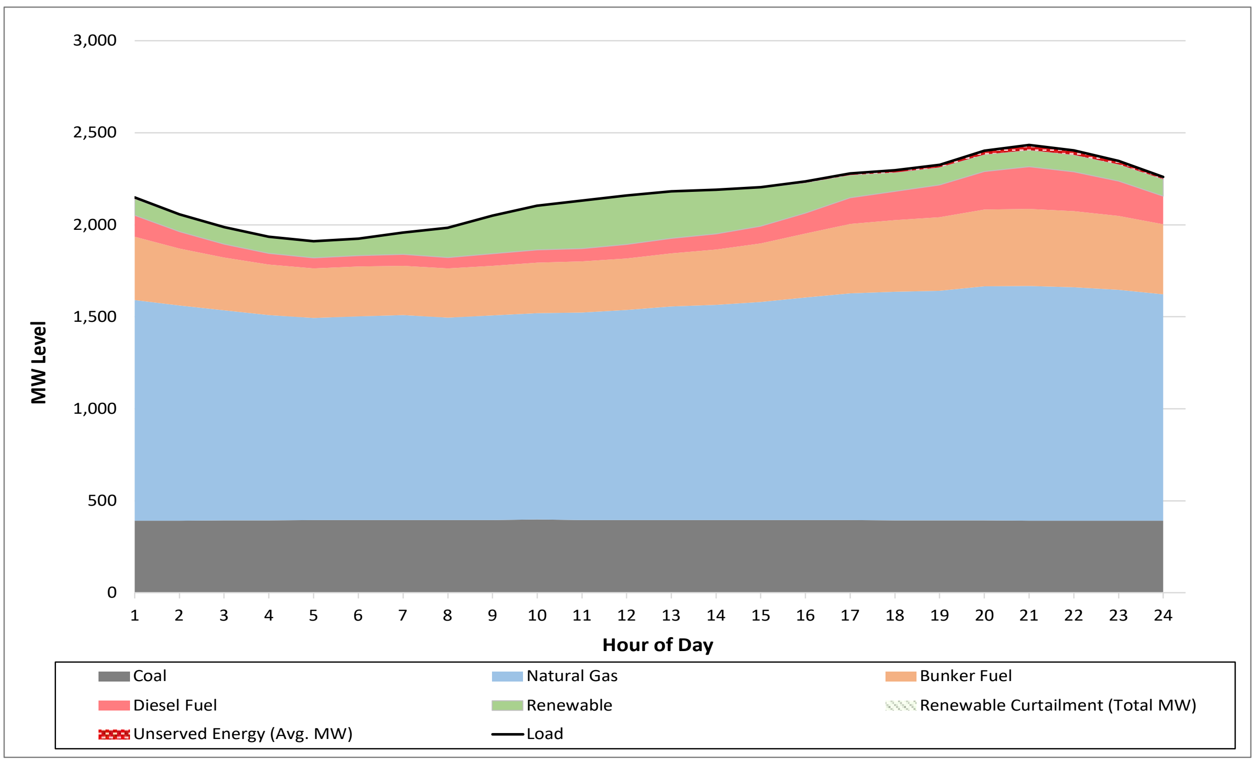
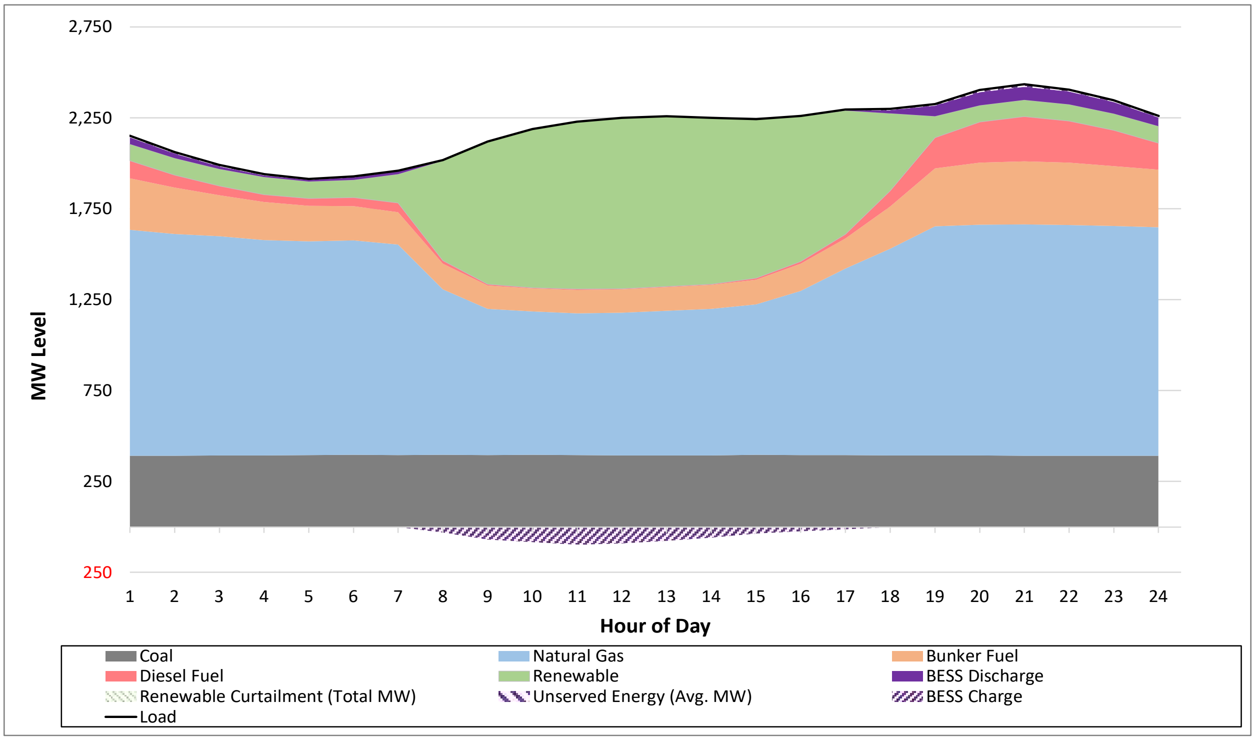


Figure A-72: Forecasted Average Generator Dispatch in the Current System + Tranche 1 Projects



As can be observed by comparing the two figures, the addition of Tranche 1 projects results in a significant amount of renewable generation during the middle of the day. In order for the system to make room for this generation, the operating thermal power plants on the island are required to turn down during the middle of the day. The generators that are primarily able to do so are the generators that consume natural gas. Generators that consume bunker fuel cannot be turned down much further since they are already near or at their minimum stable operating levels, while the generator that consumes coal (AES) is the lowest cost generator in Puerto Rico and thus is not turned down much for economic reasons. Since the thermal generators are needed to meet load during the evening (when solar generation falls to zero), the thermal generators cannot be turned off during the middle of the day because most would not be able to start back up in time to meet the evening peak load.

For reference, there was little to no forecasted curtailment in this simulation. This is in part because the storage and solar PV are modeled as paired, and the storage charged by solar PV reduces the need to curtail the additional installed solar. Additional tranches of standalone renewable generation are expected to result in higher levels of renewable curtailment.

The addition of Tranche 1 results in a need for the existing thermal generators in Puerto Rico to significantly reduce generation during the middle of the day, then quickly increase generation for the evening; this is also known as generator cycling. One consequence of increased cycling is additional wear on generator equipment, which results in more frequent planned outages and potentially a higher risk of forced outages. From a resource adequacy perspective, while modelling the addition of solar plus paired energy storage to the current system was found to greatly improve system resource adequacy, the impact of thermal generator cycling on planned outage frequency and forced outage rate was not considered in the resource adequacy analysis. An increase in thermal generator planned outage frequency or forced outage rates will have a marginally negative impact on system resource adequacy.