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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 LUMA's Fiscal Year 2026 Resource Adequacy Study and Request for Confidential Treatment

MOTION TO SUBMIT LUMA'S FISCAL YEAR 2026 RESOURCE ADEQUACY STUDY AND REQUEST FOR CONFIDENTIAL TREATMENT

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. In attention to Section 5.13(d) of the Puerto Rico Transmission and Distribution System ("T&D System") Operation and Maintenance Agreement by and among LUMA, the Puerto Rico Electric Power Authority ("PREPA") and the Puerto Rico Public-Private Partnerships Authority dated as of June 22, 2020 (the "T&D OMA")[1], LUMA submits herein a report regarding

[1] Under Section 5.13(d) of the T&D OMA, LUMA is required to:

> (i) 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 and [applicable laws] (and which assessments and analyses PREB may request from time to time);
> (ii) […];
> (iii) meet with PREB on an annual basis to review and assess the prepared analyses, demand projections (prepared in accordance with the Integrated Resource Plan), existing System Power Supply, Legacy Generation Assets and generation assets owned by [independent power producers] related to the supply of Power and Electricity, and determine whether additional power supply sources are needed; […]
> […]

"Generation Projects" are projects or transactions with respect to "any function, service or facility of [PREPA] related to the generation of Power and Electricity […] and in respect of which [PREPA] or the Government of Puerto Rico the resource adequacy of the Puerto Rico electric system during Fiscal Year 2026, spanning from July 1, 2025 to June 30, 2026, titled "Puerto Rico Electrical System Resource Adequacy Analysis Report" and dated December 5, 2025 ("FY2026 Resource Adequacy Study"). *See Exhibit 1*.

2. The FY2026 Resource Adequacy Study summarizes the analyses conducted by LUMA to assess the adequacy of current electricity supply resources in Puerto Rico to reliably serve anticipated electricity demand during the study period. *See id*., p. 10. This study provides an assessment of electricity generation sufficiency needs by estimating the probabilistic risk of insufficient electric supply to meet the demand of Puerto Rico's electricity consumers. S*ee Exhibit 1*, p. 13. *See also id*., pp. 16, 40 and 120.[2] It includes multiple sensitivity analyses undertaken by LUMA to reveal the potential implications on resource adequacy by factors such as the addition of electricity supply resources that are expected to be added in the future, unavailability of some existing resources, and changes in electricity demand, among others. *See id*., p. 13.

3. This type of study can support the development of plans for adding new resources to serve the electric system load and the establishment of appropriate planning and operating criteria. *See id*. p. 121. However, this study is not intended to evaluate the incremental supply resources to be installed or the estimated costs of new resources or address policy impacts associated with resource expansion, which are the subject of the Integrated Resource Plan prepared

may enter into a Partnership Contract (as defined in Act 29-2009[, as amended])." *See id*. Section 1.1, p. 17. "Generation Supply Contracts" are contracts between PREPA and an independent power producer "relating to the sale and purchase of Power and Electricity including power purchase agreements". *See id*. "System Power Supply" refers to "electric capacity, energy and ancillary services from any power supply sources authorized under Applicable Law to operate in the Commonwealth". *See id*., p. 30. "Legacy Generation Assets" are "any power plants and any facilities, equipment and other assets related to the generation of Power and Electricity existing as of the date [of the T&D OMA] and in which [PREPA] or GenCo has an ownership or leasehold interest". *See id*., p. 19. "GenCo" means "the entity, which may be directly or indirectly owned by [PREPA or an affiliate of PREPA], that acquires or obtains ownership of the Legacy Generation Assets after the reorganization of PREPA". *Id*., p. 16. "Power and Electricity" means "the electrical energy, capacity and ancillary services available from the System Power Supply." *Id*., p. 25.

[2] It must be noted that resource adequacy does not assess any intra-regional constraints associated with transmission and distribution systems. *Id*., p. 16. Consequently, the FY 2026 Resource Adequacy Study does not discuss the implications on electricity reliability in Puerto Rico due to the state of its transmission and distribution network. *Id*.

by LUMA in Case No. NEPR-AP-2024-0004, *In Re: Review of the Puerto Rico Electric Power Authority Integrated Resource Plan*. *See id*., p. 107.

4. The FY2026 Resource Adequacy Study finds that power generation resources interconnected to Puerto Rico's electric grid are inadequate to provide electricity service at the degree of expected reliability for U.S. electric utilities. *See id*., p. 10. It further finds that major improvements in Puerto Rico's electricity resource adequacy cannot be expected unless and until resource supply is materially increased through either new resource additions or major improvements to the existing power generation fleet. *See id*.

5. LUMA welcomes the opportunity to discuss the FY2026 Resource Adequacy Study with this Energy Bureau and answer any questions it may have about this study, to further the understanding of this honorable Energy Bureau on the electric generation sufficiency needs of the Puerto Rico electric power system.

6. LUMA remains committed to working with the Energy Bureau, generators, and other stakeholders to address the systemic generation issues identified in the FY2026 Resource Adequacy Study to provide the people of Puerto Rico with safe, reliable, and clean energy.

REQUEST FOR CONFIDENTIAL TREATMENT

7. LUMA respectfully submits that *Exhibit 1* contains confidential information that garners protection from public disclosure pursuant to applicable law and regulations as explained below. Therefore, LUMA is submitting a revised, redacted version of the FY2026 Resource Adequacy Study for public disclosure with this Motion.

8. Section 6.15 of the *Puerto Rico Energy Transformation and RELIEF Act*, Act No. 57-2014, as amended ("Act 57-2014") regulates the management of confidential information filed before this Energy Bureau, providing, in pertinent part, that: "[i]f any person who is required to

submit information to the Energy [Bureau] believes that the information to be submitted has any confidentiality privilege, such person may request the Commission to treat such information as such [….]" 22 LPRA §1054n. If the Energy Bureau determines, after appropriate evaluation, that the information should be protected, "it shall grant such protection in a manner that least affects the public interest, transparency, and the rights of the parties involved in the administrative procedure in which the allegedly confidential document is submitted." *Id.* Section 6.15 (a).

9. In connection with the duties of electric power service companies, Section 1.10 (i) of *Puerto Rico Energy Public Policy Act, Act No. 17-2019*, as amended, provides that electric power service companies shall submit information requested by customers, except for confidential information in accordance with the Rules of Evidence of Puerto Rico. 22 LPRA §1141i.

10. Access to the confidential information shall be provided "only to the lawyers and external consultants involved in the administrative process after the execution of a confidentiality agreement." *Id.* Section 6.15(b), 22 LPRA §1054n. Finally, Act 57-2014 provides that this Energy Bureau "shall keep the documents submitted for its consideration out of public reach only in exceptional cases. In these cases, the information shall be duly safeguarded and delivered exclusively to the personnel of the [Energy Bureau] who need to know such information under nondisclosure agreements. However, the [Energy Bureau] shall direct that a non-confidential copy be furnished for public review." *Id.* Section 6.15(c).

11. The Energy Bureau's Policy on Management of Confidential Information, CEPR-MI-2016-0009, issued on August 31, 2016, as amended on September 21, 2016 ("Policy on Confidential Information") details the procedures that a party should follow to request that a document or portion thereof be afforded confidential treatment.[3] The Policy on Confidential

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[3] In essence, the Policy on Confidential Information requires the identification of confidential information and the

Information also provides that "[a]ny document designated by the [Energy Bureau] as Validated Confidential Information because it is a trade secret under Act 80-2011 may only be accessed by the Producing Party and the [Energy Bureau], unless otherwise set forth by the [Energy Bureau] or any competent court". *Id.* at § D (on Access to Validated Confidential Information).

12. Relatedly, Regulation 8543 includes a provision for filing confidential information in adjudicatory proceedings before this Honorable Energy Bureau.[4]

13. Under the *Industrial and Trade Secret Protection Act of Puerto Rico*, Act. 80-2011, as amended, 10 LPRA § 4131-4144, industrial or trade secrets are deemed to be any information:

> (a) That has a present or a potential independent financial value or that provides a business advantage, insofar as such information is not common knowledge or readily accessible through proper means by persons who could make a monetary profit from the use or disclosure of such information, and
>
> (b) for which reasonable security measures have been taken, as circumstances dictate, to maintain its confidentiality.

Id. § 4132, Section 3 of Act 80-2011.

14. Trade secrets include, but are not limited to, processes, methods and mechanisms, manufacturing processes, formulas, projects or patterns to develop machinery and lists of specialized clients that may afford an advantage to a competitor. *See* Statement of Motives, Act

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filing of a memorandum of law explaining the legal basis and supporting evidence for a request to file information confidentially. *See* CEPR-MI-2016-0009, Section A, as amended by the Resolution of September 16, 2016, CEPR-MI-2016-0009. The memorandum should also include a table that identifies the confidential information, a summary of the legal basis for the confidential designation and a summary of the reasons why each claim or designation conforms to the applicable legal basis of confidentiality. *Id.* paragraph 3. The party who seeks confidential treatment of information filed with the Energy Bureau must also file both a "redacted" or "public version" and an "unredacted" or "confidential" version of the document that contains confidential information. *Id.* paragraph 6.

[4] To wit, Section 1.15 provides that,

> a person has the duty to disclose information to the [Energy Bureau] considered to be privileged pursuant to the Rules of Evidence, said person shall identify the allegedly privileged information, request the [Energy Bureau] the protection of said information, and provide supportive arguments, in writing, for a claim of information of privileged nature. The [Energy Bureau] shall evaluate the petition and, if it understands [that] the material merits protection, proceed accordingly to [. . .] Article 6.15 of Act No. 57-2014, as amended.

80-2011. Protected trade secrets include any information bearing commercial or industrial value that the owner reasonably protects from disclosure. *Id. See also* Sections 4(ix) and (x) of the *Puerto Rico Open Government Data Act*, Act 122-2019, 3 LPRA § 9894 (exempting from public disclosure (1) commercial or financial information whose disclosure will cause competitive harm and (2) trade secrets protected by a contract, statute, or judicial decision).

15. The Puerto Rico Supreme Court has explained that the trade secrets privilege protects free enterprise and extends to commercial information that is confidential in nature. *Ponce Adv. Med. V. Santigo Gonzalez*, 197 DPR 891, 901-02 (2017); *see also Next Step Medical Co. v. MCS Advantage Inc*., KLCE201601116, 2016 WL 6520173 (P.R. Court of Appeals, September 13, 2016) (holding that in Puerto Rico, what constitutes trade secrets is evaluated applying a broad definition). A trade secret includes any and all information (i) from which a real or potential value or economic advantage may be derived; (ii) that is not common knowledge or accessible through other means; and (iii) as to which reasonable security measures have been adopted to keep the information confidential. *Ponce Adv. Medical*, 197 DPR at 906.

16. Portions of the Resource Adequacy Study identified in the table included in this Motion contain proprietary heat rates belonging to private third parties. These values constitute commercial or financial information within Section 4(x) of Act 122-2019, as they possess independent economic value and provide a business advantage by virtue of not being generally known or readily accessible to competitors or the public. Moreover, reasonable measures have been taken to maintain the confidentiality of this information, consistent with statutory requirements. Disclosure of these heat rates would risk causing competitive harm to the third party and undermining the public policy favoring the protection of commercially valuable confidential information. Therefore, LUMA requests that the Energy Bureau grant confidential treatment to

these heat rates that are proprietary to third parties to ensure compliance with the statutory protections afforded under Puerto Rico law.

17. In compliance with the Energy Bureau's Policy on Confidential Information, a table summarizing the hallmarks of this request for information is included below.

Document	Name	Pages in which Confidential Information is Found	Summary of Legal Basis for Confidentiality Protection	Date Filed
Exhibit 1	Table D-1: Puerto Rico Thermal Electric Fleet	Page 133 (Cells in table providing Forced Outage Rate of AES1 and AES2)	Third-Party Proprietary Information	December 5, 2025
Exhibit 1	Table D-1: Puerto Rico Thermal Electric Fleet	Page 134 (Cell in table providing Forced Outage Rate of EcoEléctrica)	Third-Party Proprietary Information	December 5, 2025

WHEREFORE, LUMA respectfully requests that the Energy Bureau **take notice** of the foregoing, **accept** the FY2026 Resource Adequacy Study included as *Exhibit 1*; and **approve the request for confidential treatment** of the information in *Exhibit 1* identified as confidential in this motion.

RESPECTFULLY SUBMITTED.

In San Juan, Puerto Rico, this 5th day of December 2025.

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

FY2026 Resource Adequacy Study [Redacted Public Version]

[Confidential version submitted under seal]

Puerto Rico Electrical System Resource Adequacy Analysis Report

NEPR-MI-2022-0002

Fiscal Year 2026

December 5, 2025

Contents

Figures

Tables

Acronyms and Abbreviations

Acronym/Abbreviation	Definition/Clarification
BESS	Battery Energy Storage System
BTM	Behind The Meter
BUGP	Back-Up Generators Program
CAISO	California Independent System Operator
CBES	Customer Battery Energy Storage
CC	Combined Cycle
CPUC	California Public Utilities Commission
CT	Combustion Turbine
DER	Distributed Energy Resources
DG	Distributed Generation
DR	Demand Response
ELCC	Effective Load Carrying Capacity
ERM	Energy Reserve Margin
ETR	Estimated Time of Return
EUE	Expected Unserved Energy
EV	Electric Vehicle
FEMA	U.S. Federal Emergency Management Agency
FPSC	Florida Public Service Commission
FRCC	Florida Reliability Coordinating Council
FY2023	Fiscal Year 2023
FY2024	Fiscal Year 2024
FY2025	Fiscal Year 2025
FY2026	Fiscal Year 2026
GPA	Guam Power Authority
HECO	Hawaiian Electric Company
HPUC	Hawaii Public Utilities Commission
IPP	Independent Power Producer
IRP	Integrated Resource Plan
ISO	Independent System Operator

Acronym/Abbreviation	Definition/Clarification
LOLE	Loss of Load Expectation (days per year, multiple events in a single day count as 1 LOLE)
LOLH	Loss Of Load Hours
LOLP	Loss Of Load Probability
LSE	Load Serving Entity
LUMA	LUMA Energy [also, the “System Operator”]
MW	Megawatt
MWh	Megawatt Hour
NERC	North American Electric Reliability Corporation
NREL	U.S. National Renewable Energy Laboratory
PJM	Pennsylvania-New Jersey-Maryland (large grid operator on mainland U.S.)
PLEXOS	PLEXOS (a production cost model)
PPOA	Power Purchase and Operating Agreement
PRAS	Probabilistic Resource Adequacy Simulation (resource adequacy model)
PREB	Puerto Rico Energy Bureau
PREPA	Puerto Rico Electric Power Authority
PRM	Planning Reserve Margin
PV	Photovoltaic
STM or STG	Steam Turbine
T&D	Transmission & Distribution
USVI	U.S. Virgin Islands
VIWAPA	Virgin Islands Water and Power Authority
VPP	Virtual Power Plant
VR	Voltage Reduction

Executive Summary

This report summarizes the analyses conducted by LUMA to assess the adequacy of current electricity supply resources in Puerto Rico to reliably serve anticipated electricity demand during Fiscal Year 2026 (FY2026), from July 1, 2025, to June 30, 2026.

The report finds that the **power generation resources interconnected to Puerto Rico's electric grid are inadequate to provide electricity service at the degree of expected reliability for U.S. electric utilities**. Age and underinvestment have increased the downtime of the generation fleet and have reduced the maximum output that generators can provide when operational. With available capacity far lower than indicated by nameplate ratings, total supply resources frequently are insufficient to ensure continuously reliable grid operation. In instances when power generation capacity is inadequate to meet demand, the system operator must initiate load-shedding events, in which electricity service to selected customers is interrupted. Such capacity shortfalls are most prevalent during summer evening hours when electricity demand is highest.

Based on the current status of the system (Base Case conditions), it is expected that there will be **37** days during FY2026 in which load-shedding events will be initiated in Puerto Rico due to inadequate resources, and that these load-shedding events will total an expected **196** hours of electricity service interruption for the average customer over the course of the year. The degree of expected load-shedding frequency and duration is far higher than the level of electric system performance used as a benchmark for planning purposes at most U.S. utilities, which is 0.1 load shedding events per year.

It is important to emphasize that the presented values are averages that result from a set of statistical methodologies. The amount of load-shedding that occurs during FY2026 will be influenced by actual weather conditions and actual outages of power plants – future circumstances that are intrinsically unknown and for which these analyses provide reasonable indicators of expected Puerto Rico electric system performance. During FY2026, load-shedding events could occur on fewer than 37 days and aggregate to less than 196 hours, with equal likelihood load-shed frequency and duration could also exceed expected levels.

Multiple sensitivity analyses were conducted to provide a range of potential variations in load-shedding outcomes. One of the principal findings indicates that the addition of 900 MW of generation always available, "perfect" resources, would improve resource adequacy in Puerto Rico to levels approaching U.S. mainland standards. Conversely, the prolonged outage of a major power plant would make the current resource inadequacy dramatically worse.

Ultimately, **major improvements in Puerto Rico's electricity resource adequacy cannot be expected unless and until resource supply is materially increased** through either new resource additions or major improvements to the existing power generation fleet. Base Case results from this resource adequacy study are similar to FY2025 Resource Adequacy Base Case results. Resource additions require both major capital investment and a long time to complete, and major improvements to the existing power plant fleet cannot be accomplished without lengthy outages that would worsen resource adequacy in the interim. As a result, **Puerto Rico's resource adequacy deficiencies will not be easily remedied. Expectations about future improvements in resource adequacy should be set accordingly**.

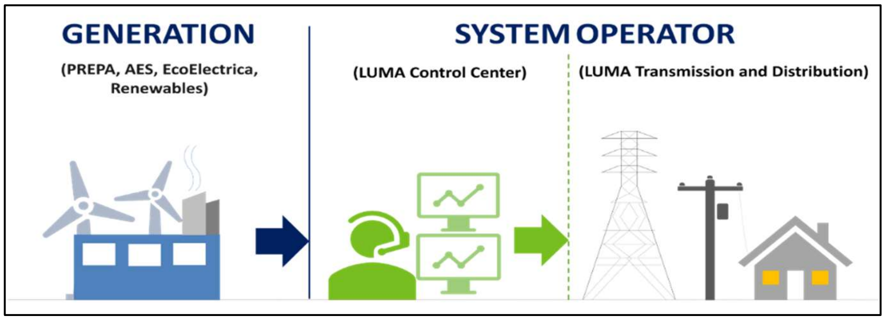
Reflecting these needs, two emergency orders from the US Department of Energy (DOE) were issued on May 16, 2025, to address the acute shortage of dispatchable generation capacity and accelerate maintenance works on the transmission system[1]. Supporting these emergency orders, the government of Puerto Rico also issued executive orders to address the electric infrastructure and expand available capacity[2]. These orders have accelerated the procurement of new resources to be added to the electric system to improve resiliency.

Roles and Responsibilities

The legal framework for the electric system in Puerto Rico, identified in Act 17-2019 and Act 57-2014, establishes the division of power generation from the transmission and distribution of electricity activities. Previously, these functions were performed by the Puerto Rico Electric Power Authority (PREPA). Today, these utility functions have been delegated to private companies, and responsibilities are distributed as follows:

1. Generators: Oversee energy production and fuel (thermal resources only) purchases to generate power.
    a. Genera PR: operates and maintains the power plants owned by PREPA.
    b. Independent Power Producers (IPPs): run and maintain their own power plants. In Puerto Rico, there are two thermal power plants and eleven renewable power plants owned and operated by IPPs.
2. Transmission and Distribution (T&D) System Operator: Operates and maintains the transmission and distribution system to deliver energy to customers.
    a. **LUMA does not own or operate generation**. Its role is to maintain and operate the Transmission and Distribution (T&D) system, plan, and ensure the power generated by others (Genera PR, EcoEléctrica, AES, etc.) is delivered to the customer reliably.

Figure ES-1: Generator and T&D System Operator of Puerto Rico



[1] *Energy Department announces emergency actions to provide overdue relief to Puerto Rico power grid*. (2025, May 19). Energy.gov. https://www.energy.gov/articles/energy-department-announces-emergency-actions-provide-overdue-relief-puerto-rico-power

[2] *PR expands energy emergency declaration | New Fortress Energy*. (n.d.). https://www.newfortressenergy.com/stories/puerto-rico-issues-executive-order-expand-energy-emergency-declaration

LUMA's responsibilities are stipulated by the Puerto Rico Transmission and Distribution Operation and Maintenance Agreement (T&D OMA) 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. As part of these responsibilities, LUMA carries out multiple activities to improve the reliability and resilience of the Puerto Rico electric system. Among these activities, LUMA conducts studies to assess resource adequacy to meet the energy demands of Puerto Rico.

This report presents an updated set of analyses to evaluate electricity resource adequacy in Puerto Rico. LUMA is committed to improving the Puerto Rico electric system, and this resource adequacy assessment makes a significant contribution by providing information to explain how the system is expected to perform in the coming year and help stakeholders involved in the Puerto Rico electricity industry make necessary decisions aligned with system realities.

Report Scope and Methodology

Resource adequacy analyses quantify the risk that an electricity system is unable to serve system load because of insufficient generation capacity. Electricity system resource adequacy guidelines are based on regulatory requirements, system operator policies, and best utility practices. Many of these policies have been set by the U.S. Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Corporation (NERC), state/territory governments, and regional regulating authorities.

Although FERC, NERC, and other state regulators and governments have no jurisdiction over the Puerto Rico electricity system, the resource adequacy practices that have resulted from their collective work represent best practices that LUMA believes should be used for assessing the reliability of the Puerto Rico electricity grid. Consequently, the methodology followed in this report is consistent with this collective body of work. Resource adequacy methodology is discussed in further detail in Appendix C.

This analysis covers Fiscal Year 2026 (FY2026), which spans from July 1, 2025, to June 30, 2026. Data and assumptions used in the analysis are based on historical information gathered from the Puerto Rico electricity system. Details about data sources and assumptions made and utilized in the resource adequacy analyses described herein are presented in Appendix B.

The methodology to evaluate resource adequacy uses probabilistic techniques founded on factors such as generating capacity of the power plants, power plant outage rates, and electricity demand. The analysis aims to quantify the expected frequency that the power system will be unable to meet demand.

The results of resource adequacy analyses are typically described by using one or more metrics that aim to capture key concepts associated with the possible loss of electricity service. Two resource adequacy metrics are commonly used:

- **Loss of load expectation (LOLE):** the estimated number of days over a defined period that generation supplies will be inadequate to meet demand at least once during that day.
- **Loss of load hours (LOLH):** the estimated number of hours over a defined period that generation supplies will be inadequate to meet demand

Overall, resource adequacy analysis is an essential tool for assessing the power system's reliability and a major contributor to helping regulators and utilities make sound decisions about future power generation.

Key Findings

This Resource Adequacy report estimates the probabilistic risk of insufficient electricity supply to meet the demands of Puerto Rico's electric customers. The report is centered on a "Base Case" assessment, which presents an average expectation of electricity resource adequacy in Puerto Rico for FY2026 under the current status of the electricity system. In addition, multiple other sensitivity analyses were undertaken to reveal the potential implications on resource adequacy, assuming the addition of electricity supply resources that are expected to be added in the future, such as renewable projects, Battery Energy Storage Systems (BESS), thermal projects, and demand response (DR) programs. Other sensitivities analyze the unavailability of some of the existing resources, changes in electricity demand levels, and how a major event (e.g., hurricane) could impact resource adequacy. All the assumptions from these alternate sensitivities were based on and analyzed by altering the Base Case assumptions.

Two drivers most critically affect forecasted LOLE & LOLH: electric supply resources (referred to as **Availability)** and **Electric Demand** (also known as **System Load,** or **Load**). Any reliable electric system requires more availability than the System Load, to meet or be able to supply the entire Electric Demand. When the Electric Demand exceeds Availability, load sheds occur due to electric supply shortfall (which is forecasted as LOLE (days) & LOLH (hours). When total Availability is closer to the total Electric Demand, the higher the risk and likelihood of having a load shed, in which electricity is interrupted to some customers. The difference between Availability and Load is called **Capacity Reserves** (or **Reserves**), which represents the amount of available generation remaining that can be utilized if Demand increases or if a generating resource fails. When Reserves fall below zero, load shedding is unavoidable.

The electric system supply is operated to meet the Electric Demand. Over the course of every day, Electric Demand varies (which is known as Load Shape). The Load Shape of Electric Demand differs regionally around the world, due to differences in climate, the nature of the local economy, and cultural influences. Although at some hours of the day the Electric Demand is lower than in other hours, the total availability always needs to be sufficient (higher than the Electric Demand) at all hours of the day. More detailed analysis and information about Availability can be referred to in Section 2.1, for Load/Demand in Section 2.2, and for Capacity Reserves in Section 2.3.

Loss of Load Expectation (LOLE): In the Base Case assessment, the estimated LOLE is **36.9 days per year**. This means that, in Puerto Rico, electricity service interruptions due to insufficient electricity supplies should be expected on 36.9 days during FY2026. This resulting LOLE equates to approximately 3 days each month in which load-shed events can be expected, with more load shedding likely to occur in summer months (when demand is highest) and less load shedding in winter months. This degree of load shedding is consistent with historical load-shedding data from recent years, as shown in Figure 3-1.

The LOLE benchmark used for planning purposes at many U.S. utilities is **1 LOLE day each 10 years (or 0.1 days per year)**. Thus, the expected **36.9 LOLE days** imply that expected load shedding activity in Puerto Rico during FY2026 due to resource inadequacy is **369 times higher than** electric industry standards

Loss of Load Hours (LOLH): In the Base Case, the estimated LOLH is **196.3 hours per year**, meaning that this is the expected approximate number of hours during FY2026 when Puerto Rico's electricity supply is expected to be deficient to serve the full load, and load-shedding could occur.

Table ES-1 shows the LOLE and LOLH results of the Base Case and the sensitivities that were analyzed for this FY2026 Resource Adequacy Report. The first row contains the Base Case results, and the following rows illustrate the sensitivity results.

Table ES-1: Resource Adequacy Base Case and Sensitivities LOLE & LOLH results

Sensitivity Grouping	Sensitivity	Loss of Load Expectation (LOLE) days/year	Loss of Load Hours (LOLH) hours/year
	Base Case	36.9	196.3
Unavailability of resources	Unavailability of upcoming projects for FY2026	42.5	221.0
	Unavailability of TM generators	101.4	699.1
	Unavailability of Costa Sur 6	83.0	520.5
	Unavailability of AES	123.3	870.0
Addition of multiple resources	Addition of future solar-only projects (Tranche 1 + non-tranche solar)	36.6	175.6
	Addition of ASAP BESS projects (SO 1)	20.5	119.1
	Addition of ASAP BESS projects (SO1 + SO2)	10.5	66.0
	Addition of Genera BESS projects	13.3	81.6
	Addition of LUMA's 4x25 BESS projects	26.3	146.6
	Addition of Tranche 1 projects (Solar & BESS)	7.5	34.8
	Addition of Tranche 1 + ASAP (SO 1 & SO 2) + Genera BESS + LUMA 4x25 BESS	2.0	10.4
	Addition of Energiza project	5.3	22.0
	Addition of Genera peakers	12.6	55.9
Load/Demand affected sensitivities	Load increase sensitivity (+10%)	90.2	571.0
	Load decrease sensitivity (-10%)	11.3	51.9
	Addition of Electric Vehicles load	38.0	202.3
	Unavailability of Distributed Generation (DG)	37.2	207.8
	CBES+ (full FY2026)	33.9	183.1

Sensitivity Grouping	Sensitivity	Loss of Load Expectation (LOLE) days/year	Loss of Load Hours (LOLH) hours/year
	Backup generators	32.0	175.4
	Force Majeure scenario	71.7	480.4

The FY2026 expected LOLE of 36.9 days is comparable to the expected LOLE of 36.2 days for FY2025 and is in part explained by the lack of major improvements or additions to the generation fleet modeled in both time frames.

Sensitivity results from Table ES-1 above show that losing existing thermal generation resources would significantly increase loss of load risk. On the other hand, the addition of new resources (Solar, BESS and thermal) would substantially lower the risk of load shedding in Puerto Rico.

Standalone Solar resource additions slightly reduce load shed risk, as they only generate electricity during daylight hours, whereas Demand peaks – and Reserves are scarcest -- during evening hours after the sun has set. In contrast, the addition of standalone BESS resources has a more noticeable load shed risk reduction, because they can release their stored energy during evening hours when most needed to avoid load sheds. Combined Solar & BESS resource additions result in further improvement in resource adequacy. Because they would be dispatchable at all hours, only limited by fuel availability and occasional maintenance needs, new thermal additions also have a significant impact on load shed risk reduction. Electric Demand fluctuations also affect system reliability, as shown in the demand response sensitivities. Load reduction programs help decrease LOLE and LOLH slightly by decreasing load during peak demand periods. Additionally, a force majeure event was simulated, based on past natural disasters. The increase in LOLE and LOLH is a result of the several months required for full generation availability to cover demand.

In addition to the sensitivities presented in Table ES-1, a “perfect” capacity estimation for Puerto Rico under Base Case assumptions was made. “Perfect Capacity” means generation always available, and the methodology estimates how many MWs are needed to reach the electric industry benchmark of 0.1 LOLE days. The analysis concluded that the hypothetical addition of 900 MW of perfect capacity would allow the Puerto Rico electricity system to reach 0.1 LOLE days during FY 2026. Further details on the methodology of how the 900 MW of perfect capacity was estimated are provided in Appendix B.

Report Content

The report is presented below in the following sections:

- **Section 1** introduces the key concepts underlying electricity resource adequacy analysis.
- **Section 2** provides an overview of the Puerto Rico electricity system, including a summary of supply (generation), demand (load), capacity reserves, load sheds and upcoming utility-scale projects.
- **Section 3** concludes the report by presenting the results from multiple resource adequacy analyses – including the Base Case and 20 sensitivity analyses in which various assumptions about electricity supply and demand in Puerto Rico are varied for analytical purposes.

The report is supported by four Appendices:

- **Appendix A:** provides detailed results from the 20 sensitivity analyses that were conducted as variants from the Base Case.
- **Appendix B:** provides key assumptions on power generation resources, electricity demand and energy storage for Puerto Rico that were used in the modeling analyses.
- **Appendix C:** provides further detail and description of resource adequacy practices employed in the electric utility industry.
- **Appendix D:** provides a summary of Puerto Rico's electric system fleet.

1.0 Introduction to Resource Adequacy Analysis

Generation resource adequacy analysis is focused specifically on determining the degree of generation deficiency across a regional electricity system. An overview of resource adequacy practices in the utility industry, and how they are adapted for the unique circumstances of Puerto Rico, are discussed in this chapter.

In contrast, resource adequacy does not assess any intra-regional constraints associated with transmission and distribution systems or any cost related impact due to new resources additions or improvements to the grid. Additionally, this report will not discuss the implications on electricity reliability in Puerto Rico due to the state of its transmission and distribution network. Any transmission and distribution constraints will further reduce system reliability beyond any deficiencies in generation resource adequacy described herein.

1.1 Resource Adequacy in the Electricity Industry

The focus of generation resource adequacy modeling is to determine if enough generation capacity is available to serve System Load during every hour of the study period. This information provides regulators with the quantitative tools and measures to help ensure customers will receive safe and reliable power supplies. A resource adequacy analysis determines if there is a deficit in generation resources relative to what is necessary to assure a targeted level of adequacy for good electricity service. The results of resource adequacy analysis are then used in resource planning – such as an integrated resource planning (IRP) process – to recommend investments in new projects or programs to increase system resources to meet future expected needs. The regulator and other policymakers must then approve the plan to address any anticipated generation shortfalls. LUMA recently completed an updated IRP to the Energy Bureau (filed on October 17, 2025) and other Puerto Rico stakeholders for review and discussion about decisions on future resource additions.

Resource adequacy analyses assess the risk that an electricity system may be unable to meet System Load based on current generation capacity. Resource adequacy standards and guidelines for utilities are influenced by numerous agencies, including the U.S. FERC, NERC, state/territory governments, and other regional regulating authorities. Although FERC, NERC, and other state regulators and governments have no jurisdiction over the Puerto Rico electricity system, the resource adequacy practices that have resulted from their collective body of work represent best practices that LUMA believes should be used for assessing the reliability of the Puerto Rico electricity grid. The analyses presented in this document reflect good industry practices in resource adequacy modeling. See Appendix C for further detail on best practices for resource adequacy seen among other utilities.

There is a consistent set of fundamental guidelines for performing resource adequacy analyses across the electricity 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:

- The goal of a resource adequacy analysis is to quantify how well the existing power plants in an electricity system are reliably able to serve System Load.
- The analysis calculates the estimated probability, or risk, in each hour of a forecast horizon (typically a year) that System Load might not be met by the generators delivering electricity to the system.
- 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 System Load. The resource adequacy target is typically set by the regional electricity planning authority, consistent with guidance provided by the electricity regulator.

Fundamentally, resource adequacy assessments involve the development of quantitative estimates of the probability that generation supply will be insufficient to serve System Load. Note that an indicated resource deficiency does not mean the entire electricity system will go down, blacking out service to all customers. Instead, it signifies that there is not enough generation to serve System Load, and that some customers will experience electricity outages.

The analyses presented in this report reference LOLE and LOLH.LOLE is an especially useful metric because, as shown in Section 1 of LUMA's FY2025 Resource Adequacy Report[3], common practice in the U.S. electricity industry is for utility resource adequacy to be deemed sufficient when LOLE is estimated to be no higher than 0.1 days per year (in other words, there is a 10% probability of a generation shortfall event in any given year).

Support for probability-based resource adequacy assessments has increased due to changing electricity load profiles (e.g., the addition of customer-sited rooftop solar, the adoption of electric vehicles), the growth of intermittent renewable resources (e.g., solar and wind), and other factors that affect resource adequacy. Across the global electric utility industry, several trends in supply and demand-side resources are creating significant changes in load profiles, which promotes the use of probabilistic methods of analysis. The DOE has noted that electricity demand, which remained relatively flat for a decade, is now exhibiting strong growth, driven primarily by data center construction, electric vehicle (EV) charging requirements, and building electrification. It will be challenging enough to expand electricity generation supplies adequately to meet these growing demands, but even more so if the large current fleet of power plants burning fossil fuels is simultaneously being retired to meet environmental objectives.[4]

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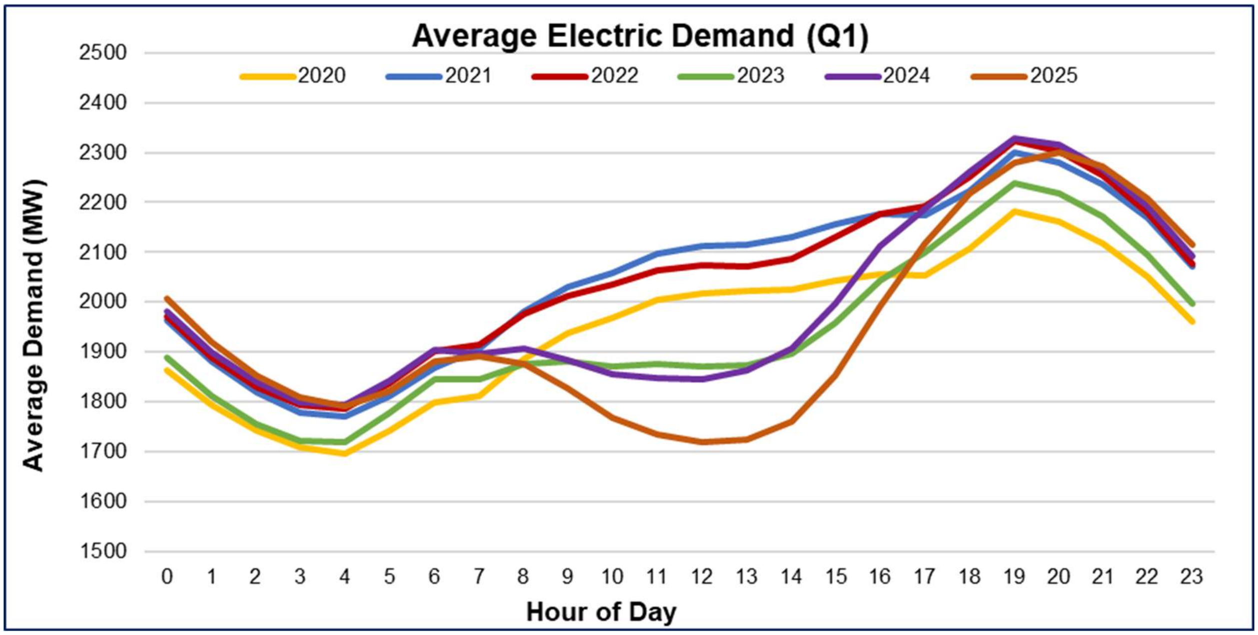
[3] LUMA Energy. (2024). Puerto Rico Electrical System Resource Adequacy Analysis Report. In *Negociado De Energía De Puerto Rico*. https://energia.pr.gov/wp-content/uploads/sites/7/2024/10/20241031-MI20220002-Resource_Adequacy-1.pdf

[4] *Electricity Demand Growth Resource hub*. (n.d.). Energy.gov. https://www.energy.gov/policy/electricity-demand-growth-resource-hub

In addition to an overall demand increase, a major trend both promoting the use of resource adequacy and reshaping resource adequacy modeling techniques is the rapid integration of renewable energy sources such as wind and solar. Countries worldwide are investing heavily in renewable energy to reduce greenhouse gas emissions and combat climate change. However, the intermittent nature of these sources presents challenges for maintaining a reliable power supply. Electrical planners now must think more carefully about how best to capture the electrical capacity contributions provided by each energy resource technology for resource adequacy calculations. These challenges are furthered by the increasing adoption of decentralized generation (DG), which is transforming the traditional centralized utility model. These sources of electricity generation are typically located on customer premises and hence are often referred to as “behind-the-meter" (BTM). DG solutions are usually installed by (or on behalf of) customers to reduce electricity bills. By far, the most common form of DG is rooftop-mounted photovoltaic (PV) systems based on solar panels, as dramatic cost declines have made customer-sited electricity generation from PV cost-competitive with grid-supplied electricity.

The integration of PV-based DG resources is leading to a phenomenon known as the “Duck Curve”. Before the significant penetration of PV, electricity system demand reached its minimum levels during overnight hours, followed by gradual increases during the day to reach peak levels in the late afternoon and early evening. However, the injection of growing volumes of PV-based electricity generation is depressing the amount of electricity the system operator is responsible for supplying during mid-day hours. When plotted over the course of the day, the difference between gross electricity volumes required by customers and the net electricity volumes required from the grid produces a figure that resembles a duck – hence the term **“Duck Curve”**. This phenomenon has started to be seen in Puerto Rico in recent years, with each year of DG capacity additions further magnifying the issue Figure 1-1.

Figure 1-1: Emergence of Duck Curve in Puerto Rico, Hourly Electricity Demand During Average Day of First Quarter



1.2 Resource Adequacy Assessment in Puerto Rico

Worldwide, resource adequacy assessments must consider multiple variables, differences, and circumstances in terms of weather, terrain, demographics, economy, politics, culture, and history (most of these locally unique). Accordingly, this section of the report discusses the distinct factors that affect resource adequacy assessment in Puerto Rico. Additionally, this section will briefly discuss previous years' Resource Adequacy assessments and compare actuals and forecasted results from the previous Resource Adequacy reports.

1.2.0 Factors that affect Resource Adequacy in Puerto Rico

Due to an aging infrastructure with resources often exceeding 40 years of service, Puerto Rico's electricity system is unreliable and prone to failure, its geographic location exposes it to natural disasters, which cause prolonged outages requiring long repair times. The outdated generation fleet contributes to significant resource adequacy deficits that are difficult to address, as improvements require extended power plant outages, while adding new capacity demands considerable capital investment and time. Consequently, expectations for future resource adequacy must be tempered, and any assessment must consider these unique challenges and the pre-existing supply situation.

Puerto Rico's generation fleet is unreliable in part because it relies heavily on a few very large power units. Four units each have a nameplate capacity over 400 MW, and if just one of them goes offline unexpectedly, the system instantly loses more than 10% of its operating capacity. This poses a major reliability risk. In contrast, most power systems in North America are large enough that losing a similarly sized unit has little impact—typically less than 1% of total capacity. Even the largest nuclear plant in the continental U.S. doesn't represent as large a share of demand as these units do in Puerto Rico.

Putting aside the possibility of major events, normal weather conditions of Puerto Rico also affect resource adequacy in ways that vary from other locations, as the electric system is confronting more intermittency issues associated with solar and wind energy. As shown above in Figure 1-1, the growing base of PV-based resources in Puerto Rico is driving down mid-day electricity demands on the system even while peak demand levels in the evening are increasing. This Load behavior means that the Puerto Rico electric system supply must increase from 2,000 MW to 3,000 MW in the 6-8 hours between mid-day and evening, implying a "ramp rate" of 125 MW – 170 MW per hour. This is one of the main reasons why, if a power plant unit unexpectedly goes offline during the ramp-up period, the system may lack sufficient capacity to respond promptly. This can lead to load shedding, not necessarily due to a generation shortfall, but rather a response shortfall, resulting in unstable system frequency.

From a resource adequacy perspective, the most important hours to consider are those in which system electricity demand is highest. In Puerto Rico, peak demand occurs daily between 6:00 p.m. and 10:00 p.m. Electricity demand increases during this span of time due to the return of residential customers to their homes after work. More details about how electricity demand in Puerto Rico behaves can be found in Section 2.2.

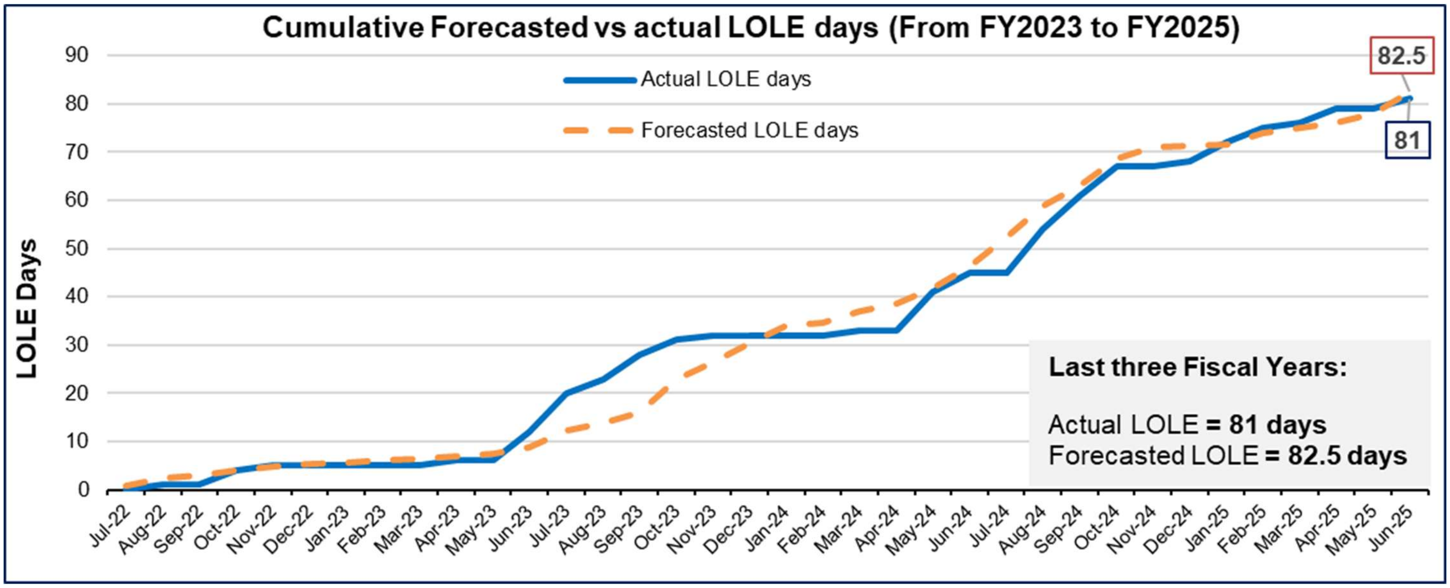
Solar production is nearly zero during peak demand hours in Puerto Rico since the sun most of the year sets before 7:00 p.m. Wind energy in Puerto Rico is generally higher during daylight hours than during overnight hours, having a similar behavior than solar resources. Together, this means that the additions of new renewable energy capacity in Puerto Rico (primarily solar) will only slightly contribute to resource adequacy during peak demand hours unless also augmented by dispatchable energy storage.

1.2.1 Previous Annual Resource Adequacy Assessments in Puerto Rico

This is the fourth annual Resource Adequacy report prepared by LUMA for the Puerto Rico electric system, since assuming operational responsibility for the Puerto Rico electric system in June 2021. In its prior reports, LUMA has consistently found and emphasized that the island has an inadequate supply of resources to deliver reasonable system reliability.

LUMA's forecasts of LOLE have shown a high degree of accuracy over the last 3 Fiscal Years. Figure 1-2 below shows the cumulative month-by-month comparison of actual vs forecasted LOLE days for each of the last three Fiscal Years.

Figure 1-2: Cumulative Actual vs Forecasted LOLE Days from FY2023 to FY2025



Accounting over the three years from July 2022 through June 2025, a total of **81** LOLE days occurred, while **82.5** LOLE days were forecasted in LUMA's resource adequacy reports from those years. In this resource adequacy report, LUMA continues to apply the same analytic methodology.

1.2.2 Resource Adequacy Summer 2025 Assessment in Puerto Rico

In March 2025, LUMA undertook an interim Resource Adequacy Assessment for Summer 2025 (the Summer Assessment) because Puerto Rico resource availability had worsened over the first months of 2025, and especially in the wake of the February 2025 outage event at the Aguirre 1 power generation unit (one of the biggest units) that has disabled the unit for an estimated period of 1 ½ years. However, in response to the Summer Assessment, several efforts were made to mitigate and reduce probable loss of load events during the summer season. These included:

- **Scheduled Planned Outages deferrals and early comebacks of some units**: Some maintenance outages initially scheduled for summer months were agreed to be postponed to periods outside summer months, with the hope of doing these maintenance in periods where Electric Demand is lower and hence reducing risk of loss of load during the highest demand months. Additionally, other baseload units were also out on maintenance, but generators managed to bring back some of these units earlier than expected to increase availability of the system and be more prepared for the summer months.

- **Expansion of Customer Battery Energy Sharing (CBES) program (called CBES+):** This program corresponds to a demand response resource where clients that have their own generating equipment (typically rooftop solar and battery resources) could export energy to the grid in case they generate more energy than it is used for their own consumption. In June 2022, LUMA proposed the Customer Battery Energy Sharing (CBES) pilot program to test the ability for energy stored in BESS sited at households to be discharged and aggregated by third-party vendors into a “virtual power plant” (VPP) for supplying the LUMA-operated electricity grid. A program of this design does not necessarily reduce the customer’s electricity demands (which can continue unaltered to be served by the customer’s BESS), but it does reduce demand on the electricity grid in the same way that traditional DR programs do. After approval by the Energy Bureau, the CBES pilot program was launched in November 2023, growing to nearly 8,000 customers, for an approximate total of 10 MW. Based on its success, and in the wake of the March 2025 release of the Summer Assessment that indicated high vulnerability to many generation shortfalls during such period, CBES was expanded in July 2025 to a much larger number of customers with BESS, enabling the provision of approximately 50 MW of VPP supply to the Puerto Rico grid for over 3 hours during the evening. The Summer Assessment report contributed to the mitigation activities described above. Other mitigation efforts were also evaluated but are still in the investigation and research phase for possible implementation in the future.

2.0 Puerto Rico’s Electrical Power System

A resource adequacy analysis relies upon many assumptions about both the supply of and the demand for electricity on the region’s electricity system. Therefore, performing a resource adequacy assessment for Puerto Rico requires a deep understanding of the island’s electricity system. This section provides an overview of Puerto Rico’s electricity system, with a deeper level of detail on data and assumptions provided in Appendix B, and detailed information on the entire electric system fleet of Puerto Rico in Appendix D.

2.1 State of Puerto Rico’s Electric Supply

The size, number, availability, and generating characteristics of the supply resources in an electricity system are some of the most important inputs into resource adequacy analyses. Currently, Puerto Rico’s electricity comes from three different sets of sources, and for the last quarter of FY2026, it is expected to have a fourth source of electricity:

- **Thermal power plants:** power plants that burn fossil fuels to produce energy for supply to the Puerto Rico grid.
- **Renewable power plants:** power plants that supply energy to the Puerto Rico grid without burning fossil fuels, such as solar, wind, landfill gas, and hydroelectric generators.
- **“Behind-the-meter" (BTM) generators:** solar panels or other equipment located on customer premises for supplying energy directly to customers.

- **Battery Energy Storage System "BESS":** New projects of utility-scale batteries that can store and discharge energy to the Puerto Rico grid.

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

2.1.0 Thermal Power Plants

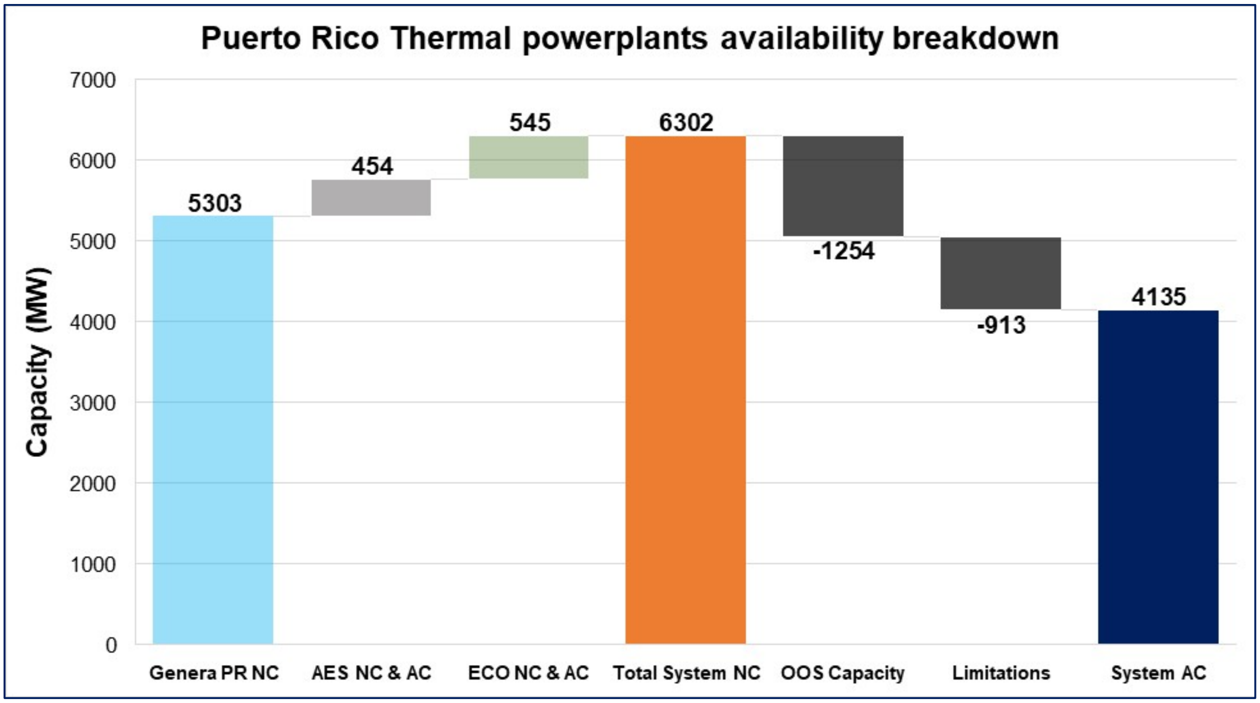
For FY2026, thermal power plants have an aggregate available capacity of 4,435 MW (4,135 MW if we consider Aguirre 1 unavailable)[5], accounting for approximately 70% of the total installed (or nameplate) thermal capacity (6,302 MW) in Puerto Rico. The remaining 1,867 MW of capacity is installed but unavailable, either due to retirement or limitations in output. Consequently, it is vital to have a good understanding of Puerto Rico's thermal power plant fleet as a foundation for resource adequacy assessment in Puerto Rico.

Thermal power plants burn fossil fuels, such as natural gas, fuel oil (sometimes called "bunker" or "residual" fuel), diesel fuel, and coal. An essential characteristic of these plants is that they are "dispatchable", meaning they can be throttled up and down and turned off or on at the system operator's command by modulating fuel consumption at any hour of the day, if available.

Figure 2-1 summarizes key parameters for the operating thermal power plant fleet in Puerto Rico. Nameplate (installed) capacity categorized by the current thermal generation operators (Genera, AES and EcoEléctrica), capacity out of service, limited capacity, and available capacity. Nameplate capacity represents the rated capacity of the power plant as of the date of initial operation, whereas available capacity represents the maximum capacity that the power plant can be depended upon to supply to the grid when called upon by the system operator. For detailed information of all the Puerto Rico electric system thermal fleet, refer to Appendix D.

[5] Aguirre 1 had a forced outage on February 2025 that will be kept out the unit the entire FY2026, reason for that will be considered out of service for the study period of this report.

Figure 2-1: Availability of Thermal Power Plants of Puerto Rico Electric System (as of FY2026)



Notes from Figure 2-1:

- **NC** - Nameplate Capacity: includes all installed thermal capacity on the Puerto Rico electric system (including decommissioned and to-be decommissioned units).
- **AC** - Available Capacity: accounts for all the thermal fleet considering their maximum operational available capacity. This number does not account for any unknown forced outages that some units could experience.
- **OOS** - Out of Service: capacity includes units being out for years without time of return. Since Aguirre 1 is going to be out the entire FY2026, it is included in this category.
- **Limitations** mean the difference between nameplate capacity and maximum capacity that some of the thermal units can provide, being limited mostly due to age (beyond their useful life).

Many of the power plants in the power plant fleet were constructed over 40 years ago, which is near or beyond the projected useful life of these facilities. Most of the legacy fleet has received suboptimal levels of investment over decades of operation. As a result, available capacity today for many of these units is lower (and sometimes, far lower) than nameplate capacity ratings established decades ago.

Historically, the forced outage rates of many thermal power plants have been very high, with approximately 2,500 MW of Puerto Rico's installed generators having forced outage rates of 15% or more, and much higher for some units. For reference, a 15% forced outage rate in a specific unit could represent approximately 5 days per month of unavailability that the unit could be unavailable. By comparison, NERC has found that the average forced outage rate of gas-fired power plants in the U.S.

has been 7.7% in recent years.[6] The higher the forced outage rates, the higher the chance that the generation facility will be unavailable when needed to serve System Load, thus resulting in a shortfall of generation capacity.

In addition to increasing a plant's forced outage rate, old age and poor maintenance also increase the average duration of a forced outage, which is another very important consideration for resource adequacy. Note that non-standard replacement components may need to be custom manufactured from scratch to replace damaged equipment on Puerto Rico's aging power plants and then transported to Puerto Rico by ship and then installed by highly specialized personnel, often brought in from other jurisdictions. Age and inadequate preventative maintenance drive the need to take more frequent and longer scheduled maintenance outages than typical for power plants of a similar type and vintage that had been properly maintained.

Environmental, regulatory, and legal considerations may also impair the ability of Puerto Rico's thermal power plants to contribute to resource adequacy. The U.S. Environmental Protection Agency (EPA) regulates power plant emissions in Puerto Rico and requires thermal power plants to maintain emissions below 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 fully comply with EPA regulations, and as a result are either required to shut down or limit operation. For this analysis, units that are operable but operationally restricted are considered as available dispatchable capacity that can still contribute towards meeting System Load, because these units still can operate for short periods under emergency exceptions to avoid loss of load.

The operability of thermal power plants inherently depends upon the availability of fuel supplies. Many of the thermal power plants in Puerto Rico burn liquified natural gas (LNG), and recent experiences in Puerto Rico has shown that LNG supplies are sometimes interrupted. When this happens, generation Availability is reduced.

When the LNG supply ship serving certain units runs low, it must be replaced by another ship. During this swap, LNG delivery is paused, and the affected units must temporarily switch to diesel fuel. While these units are designed for dual-fuel use, the switching process introduces increased operational risks that can reduce their availability. Since October 2024, these fuel swaps have increased the risk of reliability issues, including reduced reserves and a higher chance of load-shedding such as:

- **Unit Trip Risk -** While these units provide flexibility by having the ability to operate either Natural Gas or Diesel fuel, the risk of swapping from one fuel to another is always imminent. A trip puts the system that LUMA Administers at risk by affecting the system's Frequency.
- **Peak Load / Frequency Regulation -** Swapping the LNG ship reduces the availability of the San Juan CC and TM units, hindering the management of supply and Frequency regulation during peak hours. The unavailability of the TM units due to a lack of LNG fuel, limits LUMA's rapid response to grid events, and increases system instability risks.
- **Economic Dispatch Disruptions -** Swapping an LNG ship negatively impacts timely LUMA Energy's ability to achieve an "economic dispatch", which is its method of using the least expensive power generation first to reduce the total generation cost for customers. Unapproved

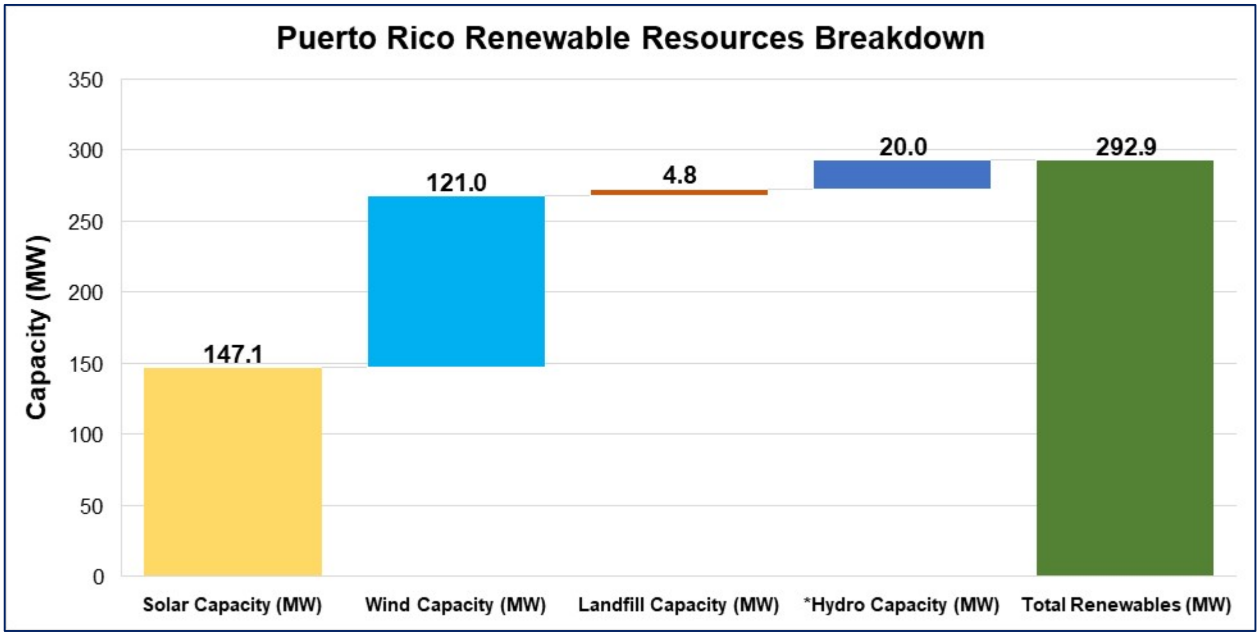
[6] NERC, 2024 State of Reliability Review, June 2024.

outages caused by the ship swap prevent LUMA from considering them into daily plans, forcing reliance on more expensive units, disrupting operations, and increasing customer costs.

2.1.1 Renewable Power Plants

In addition to the 4,435 MW of available capacity at Puerto Rico's thermal power plants, there is approximately 273 MW of nameplate capacity from utility-scale renewable power plants that are currently in operations, representing an approximate of 4% of total system installed nameplate capacity. Of the 273 MW installed capacity of renewable power plants, approximately 54% of nameplate capacity is from solar photovoltaics (PV) facilities, 44% from wind facilities, and 2% from landfill gas facilities.

Figure 2-2: Summary of Operating Renewable Power Plants



Puerto Rico has a small fleet of hydroelectric power plants with a nameplate capacity of approximately **100 MW**. Most of these units date back to the 1930s and 1940s, and many are not operational. After accounting for long-term outages and reductions in rated capacity due to damage, the effective capacity of these units is roughly **20 MW**, which is the amount of available capacity considered in the modeling process.

Figure 2-2 above reports the available capacity associated with utility-scale renewable generation. However, solar and wind energy generation facilities are intermittent in their ability to supply energy, based on sunshine and wind conditions that prevail at the power plant site, which naturally vary. However, from a resource adequacy perspective, it is critical to determine the amount of hourly renewable generation that can reliably be considered as available to serve load, and this amount will always be lower than nameplate capacity.

Rarely are solar or wind power plants able to supply their nameplate generating capacity: for solar plants, only around noontime on clear blue-sky days; for wind plants, only when the wind is steadily blowing at or above 25 mph. Most of the time, solar and wind power plants can supply something less than nameplate capacity to the grid. During overnight hours, solar power plants produce nothing; when there is no wind, wind power plants produce nothing. Therefore, each MW of capacity from a solar or wind power plant can contribute significantly less to an electricity system's resource adequacy than each MW of capacity from a thermal power plant.

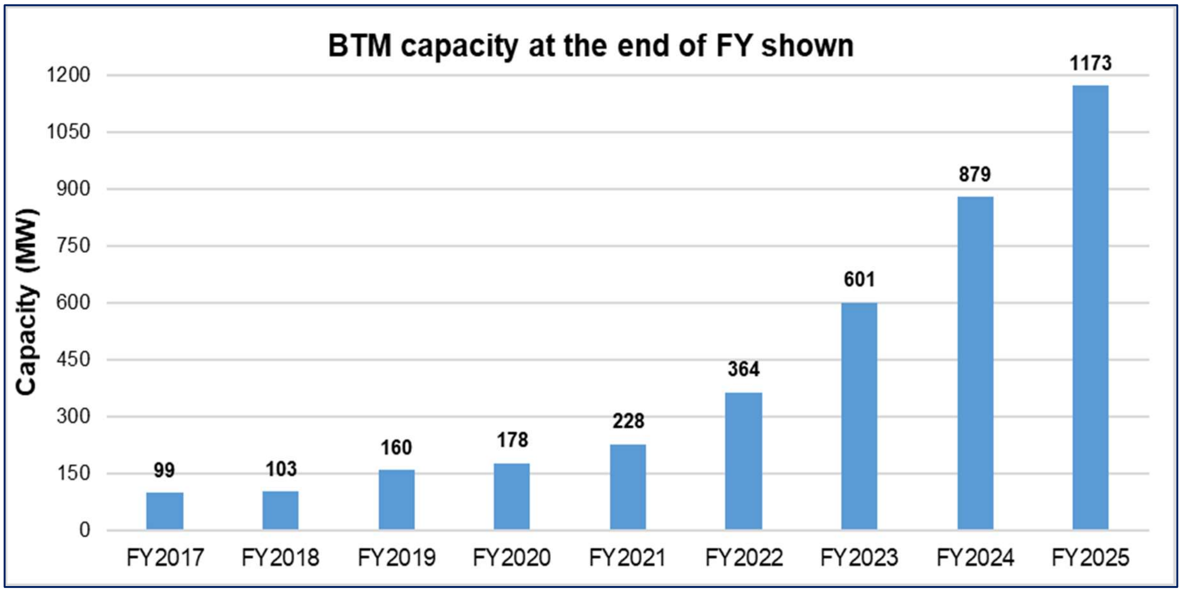
The methodology used in these analyses to properly account for renewable energy generation availability shares similarities to the methodology employed by Hawaiian Electric Company (HECO), an electric utility with many similarities to the Puerto Rico electricity system (see Appendix C). For these analyses, actual historical generation data (between 2019 and 2024) from each of the operating renewable power plants listed in Figure 2-2 was gathered to calculate the average production level for each hour of the day, which was used as the resource's capacity contribution for the resource adequacy calculations. This methodology thus captures the contributions of intermittent or variable generators towards improving system resource adequacy from a statistical standpoint, accounting for their intermittency by month and hour of day, while being based on actual historical production levels.

Properly capturing the hourly capacity contributions from variable renewable generation sources is an important consideration for resource adequacy analyses, since their hourly contributions of supply are, by definition, uncertain. Overestimating the capacity contribution of variable generators can leave the system with capacity shortfalls if the variable generators are unable to generate as expected, while underestimating the capacity contribution of variable generators can make the electrical system appear less reliable than it truly is.

2.1.2 Behind the Meter Generation Resources

In addition to the thermal power plants and renewable power plants that supply electricity to the Puerto Rico electricity grid for delivery to customers, a growing quantity of generation capacity is being installed at customer premises and supplying electricity directly to customers. Virtually all of this behind-the-meter (BTM) generation is comprised of rooftop PV systems. As of June 2025, an estimated 1,173 MW of BTM generation has been installed across Puerto Rico. Figure 2-3 below shows the annual increment in BTM capacity from FY2017 to FY2025. Since LUMA assumed operational responsibility for the electricity system in June 2021, BTM capacity has been exponentially growing from 364 MW to 1,173 MW, representing more than 800 MW of BTM capacity additions.

Figure 2-3: Summary of Annual BTM Capacity from FY2017 to FY2025



Although BTM is a supply resource that produces electricity, it is considered in resource adequacy analysis as reductions in system demand.[7] This is because, from the perspective of the system operator, BTM generation is equivalent to "negative load": small-scale and distributed across the entire service territory, BTM generation does not produce large volumes of electricity being directly injected into the electricity transmission system, and thus is outside the control of the system operator.

When BTM generation volumes are low, such as output from a rooftop PV system during a cloudy morning, the relatively small amount of electricity generated merely serves to reduce the amount of electricity that the customer purchases from the grid. Only when BTM generation volumes exceed the customer's electricity consumption does any electricity -- the surplus amount between BTM generation volumes and customer demand -- flow from the customer back to the local distribution network, thereby increasing supplies on the electricity grid. For these reasons, in this resource adequacy analysis as in most resource adequacy analyses conducted by other modelers of electric utility operations, BTM generation is accommodated by making a negative adjustment to expected customer demands rather than being modeled as a generation supply resource.

BTM generation can cause an impact on the system's frequency and stability during periods where solar irradiance is at peak value. The amount of BTM generation exported into the grid during said period is enough to disturb the frequency, potentially even causing load shed throughout the system. Given an event where household inverters for DG systems exporting this energy see a system frequency of 59.50 Hz, they all automatically and simultaneously disconnect from the grid. This scenario can cause the grid frequency to drop to levels where load shedding is inevitable. These reliability effects are outside the scope of a resource adequacy analysis but do contribute to system reliability challenges.

2.1.3 Battery Energy Storage Systems

By the end of FY2026, Puerto Rico's grid system is expected to incorporate dispatchable utility scale BESS resources. Different BESS are expected to be managed by different companies, including LUMA Energy, Genera PR, and multiple IPPs.

A major difference between BESS and other resources is that BESS stores and then dispatches energy, while generation resources (i.e. thermals, renewables, etc.) produce energy. It is therefore important to have reliable energy resources that could generate sufficient energy so the BESS resources can be fully charged to dispatch when most needed. More details about how BESS resources were modeled in the resource adequacy study can be found in Appendix B.

2.2 Puerto Rico's Electricity Demand

Electricity demand, also referred to as System Load, or load, is the other important element in resource adequacy evaluations, as electricity generators connected to the grid must be able to always meet aggregate systemwide electricity demand. In Puerto Rico, daily electricity demand fluctuates approximately between 2,000 MW and 3,000 MW during the summer months, which are the months with the highest risk of resource inadequacy.

[7] 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.

2.2.0 Understanding how Electric Demand/System Load Behaves

The methodology to develop forecasts of Electric Demand begins with the estimation of baseline consumption, assuming no major shifts in customer behavior or technology adoption. This baseline is developed using a combination of historical load data and key explanatory variables that influence electricity use. These include macroeconomic indicators such as Gross National Product and population trends, which shape long-term consumption patterns, as well as weather variables like Cooling Degree Days, which are closely tied to residential demand. If baseline development is based on a prior year in which extraordinary events occurred, adjustments are made to account for any temporary shifts in usage patterns that resulted from the extraordinary events.

The resulting baseline serves as a neutral reference point, reflecting how electricity consumption would be expected to evolve under current conditions, without the influence of emerging technologies or policy interventions. To adapt the load profile as close as possible to demand levels experienced, load modifiers are applied to the baseline Electric Demand. Load modifiers such as DG resources, Combined Heat and Power (CHP), energy efficiency, and electric vehicles. These elements can meaningfully alter demand patterns by either reducing reliance on grid electricity or introducing new load. The forecasting effort must then involve distinguishing between peak demand and consumption. While consumption (as forecasted using the approach described above) represents electricity used by customers over a period of time, peak demand refers to the highest level of electricity use at any given moment. While these two measures are related, they do not always change in sync. For instance, distributed solar power may reduce the amount of electricity consumption, but will generally not reduce peak demands that occur in evening hours during heatwaves – when Reserves are typically at their lowest and thus when the risk of load shedding is highest.

Figure 2-4 below shows the comparison between the forecast vs actual peak demand values of FY2024 and FY2025, along with the variance percentage.

Figure 2-4: Actual vs Forecasted Peak Demand Values for FY2024 and FY2025

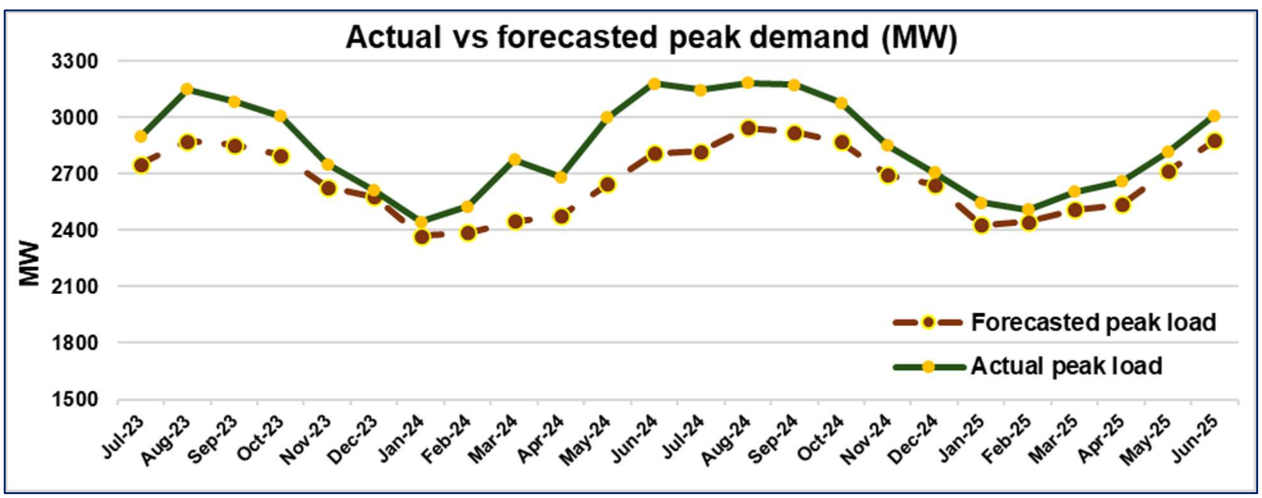
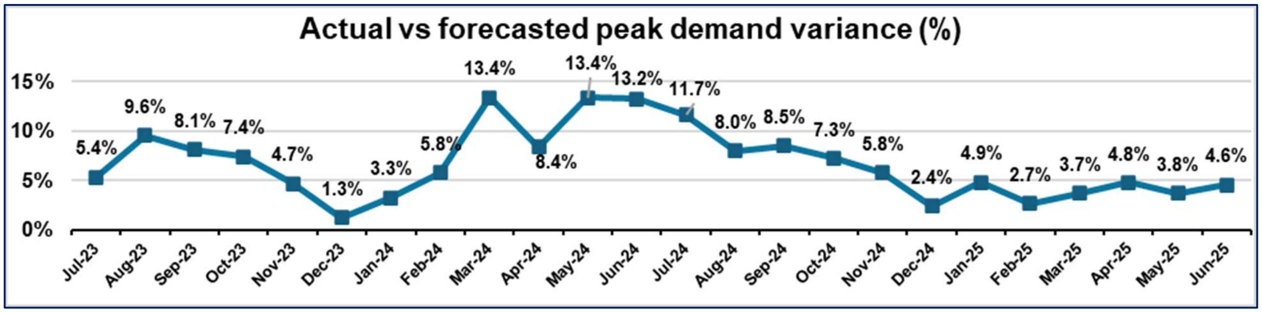


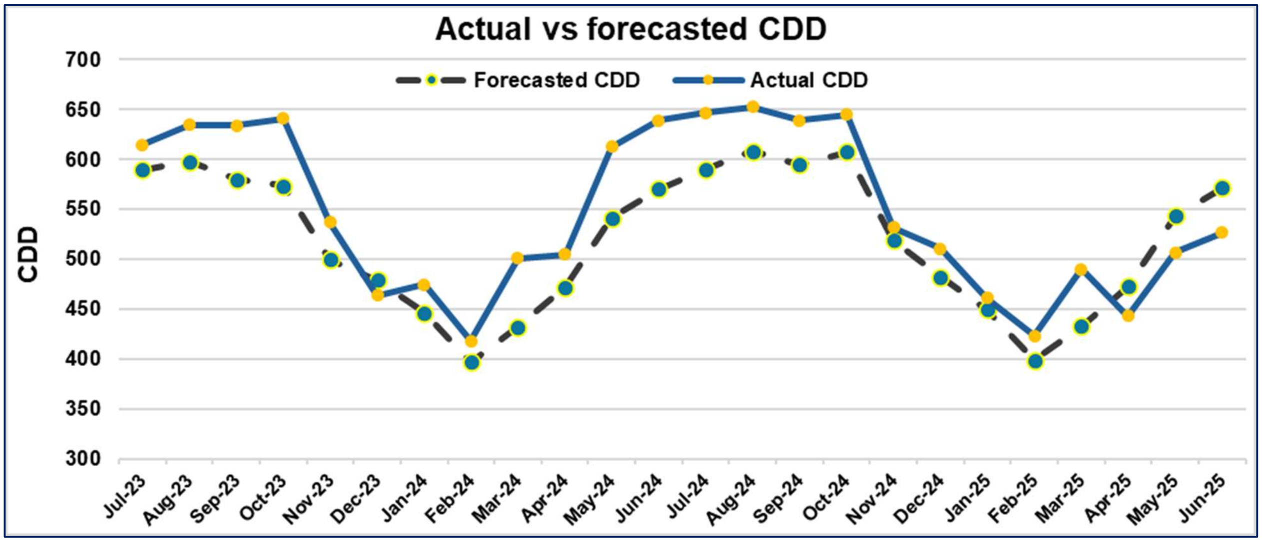
Figure 2-5: Actual vs Forecasted Peak Demand Variance for FY2024 and FY2025



The year 2024 ranked among the hottest on record, not only for Puerto Rico but also globally[8]. Temperatures are very closely tied and directly correlated with Electric Demand, meaning that in a year like 2024, when temperature rises above average, peak demand will be very likely to increase above forecasted levels as was in the case for Puerto Rico. In contrast, for the first six months of 2025, temperatures have been slightly cooler than 2024, driving peak demand variance below 5% as Figure 2-5 above shows.

As mentioned previously in this section, Cooling Degree Days (CDD) is the main driver for peak demand forecasting, meaning that any difference between forecasted and actual CDD is seen reflected in the forecast vs actual peak demand. Figure 2-6 below compares the forecast vs actual CDD for FY2024 and FY2025. When Comparing figure 2-4 and figure 2-6, it can be noticed that CDD and peak demand have a similar behavior

Figure 2-6: Actual vs Forecasted Cooling Degree Days for FY2024 and FY2025

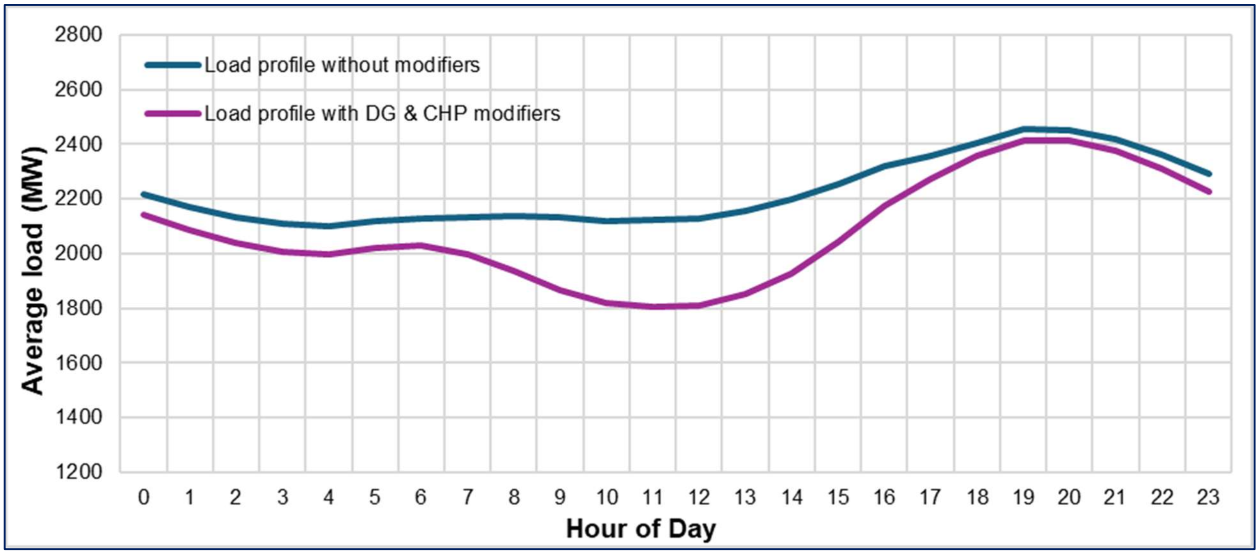


[8] NCEI.Monitoring.Info@noaa.gov. (n.d.). *Monthly Climate Reports | National Centers for Environmental Information (NCEI)*. https://www.ncei.noaa.gov/access/monitoring/monthly-report/global/202413

2.2.1 Hourly load profiles for Resource Adequacy

As in any electricity system, Puerto Rico's system demand varies for each hour of each day, throughout the year. Since a resource adequacy assessment estimates the probability that electricity generation sources will be able to satisfy demand during each of the 8,760 hours in a year, an hourly load profile must be developed for the entire year. The hourly Puerto Rico load profile incorporated into the resource adequacy analyses described in this report is based upon the actual hourly metered load values from calendar year 2024 (i.e. the “base load shape”), adjusted to correct for hours when metered data was unavailable or reflected abnormal operating conditions, and adding the DG and CHP load modifiers to account for forecasted behavior of these BTM resources. The impact of the EV load modifier is considered as a sensitivity from the Base Case, while the EE load modifier was not considered for resource adequacy modeling purposes. Figure 2-7 shows the load profile without modifiers and the load profile with the BTM (DG and CHP) resources.

Figure 2-7: Baseline and Final Hourly Load Profiles



Additionally, as discussed further in Section 3.2, sensitivities were conducted to analyze of the adoption of electric vehicles, the effect of load increases and load decreases across all hours of the year, and the impact of no DG generation resources in the system, to quantify how these demand-side factors affect resource adequacy.

Figure 2-8 below plots the load profile used for each hour in the resource adequacy analysis for FY2026. The seasonality of the load profile is notable, with summer and early fall months exhibiting higher load than other months. The reason for this is that the months of summer and the early fall are the hottest in Puerto Rico, and consequently, electricity consumption is higher during this period. Another noticeable insight is the incremental ramp up and down of the hourly load, caused by the BTM generation that is expected to continue increasing as time passes, resulting as consequence lowest demand hours during midday, while demand at peak hours continues relatively unchanged when compared to recent previous years.

Figure 2-8: Hourly Puerto Rico Load Profile in the FY2026 Base Case

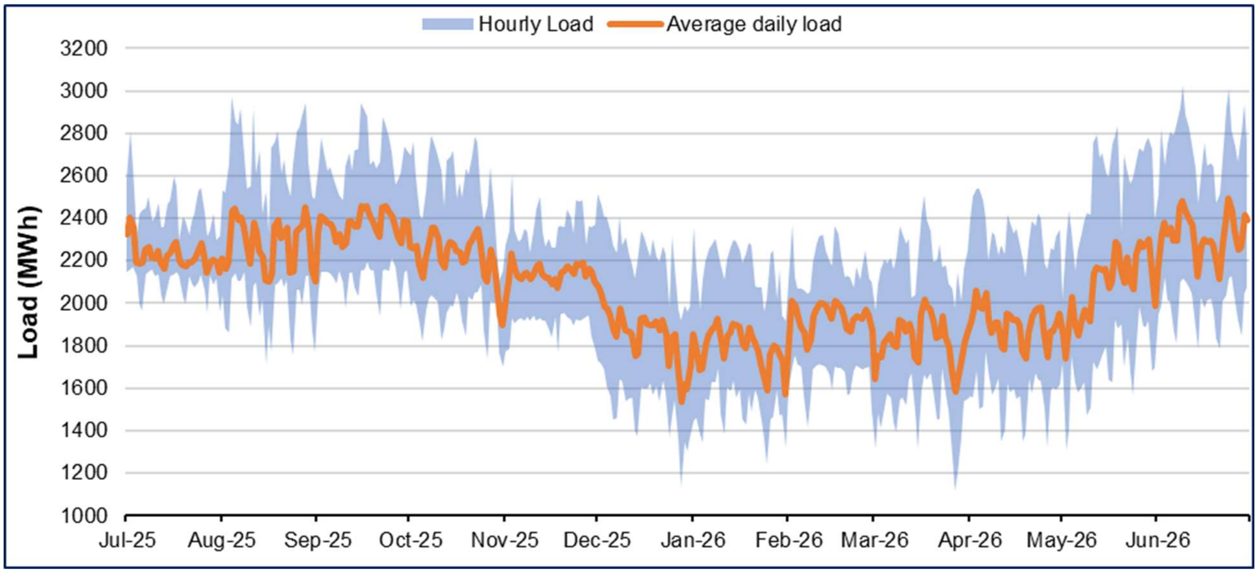
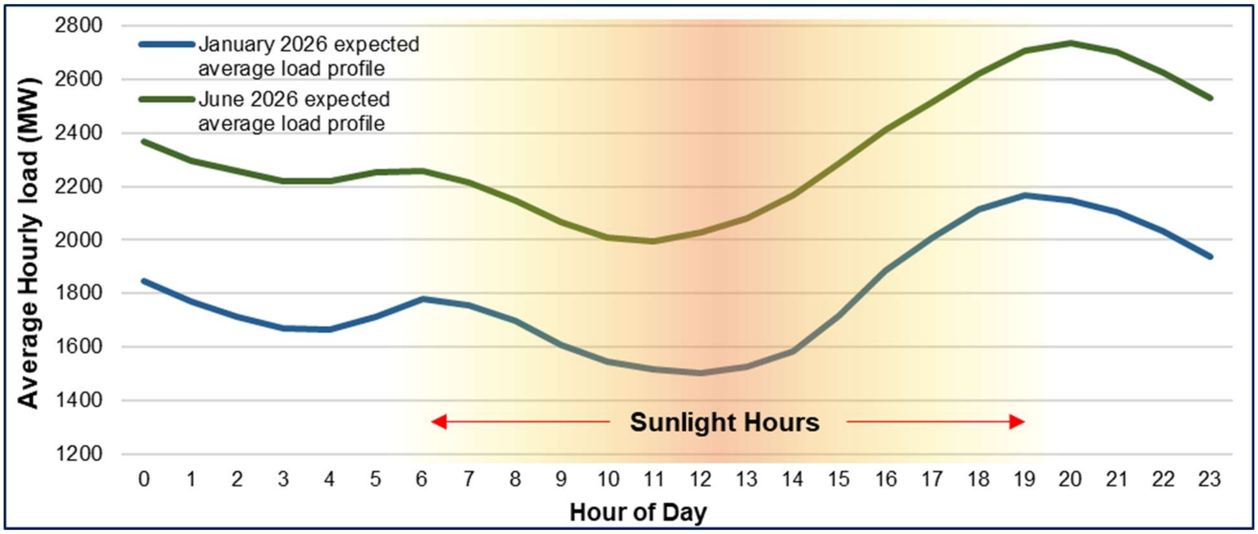


Figure 2-9 illustrates the average hour-by-hour variance in Puerto Rico electricity demand by presenting hourly load profiles for the average day in January 2026 and June 2026 (the expected lowest and highest load months, respectively). As can be observed in the figure, load levels descend through overnight hours, then have a small peak around 6:00 am – 7:00 am. After the sun rises, demand starts to descend again because of contributions from PV-based DG resources until daily minimums are reached at midday, followed by sharp increases through the afternoon as demand increases and PV-based generation decreases, finally peaking in the evening.

Figure 2-9: Hourly Puerto Rico Load During Average Days in January and June FY2026

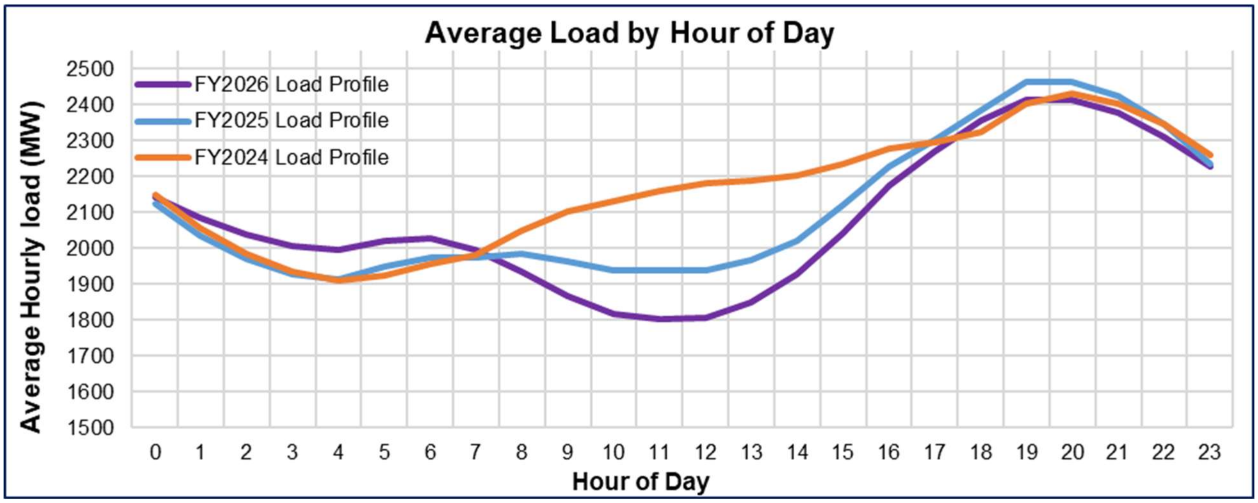


The fact that the load profile peaks in the evening highlights a challenge that many other utilities with large amounts of solar generation are currently facing. Solar power plants do not generate electricity during the evening hours when electricity demands are high, since the sun has set. For solar power resources to contribute to generation during the evening peak, they must be paired with energy storage.

The size and duration of the storage systems are important considerations in determining the extent to which solar resources will contribute to resource adequacy during peak demand hours. An overview of energy storage in Puerto Rico is discussed further in Section 2.1.3.

Demand assumptions for the Base Case reflect a forecast of changes in electricity demand patterns and levels since those experienced in 2023. Figure 2-10 compares the typical daily load profile for FY2024 and FY2025 to FY2026. As can be noticed, the Duck Curve phenomenon continues to be more noticeable in Puerto Rico: the FY2026 load profile used in these resource adequacy analyses exhibits a significant reduction of load during the daytime hours, such that minimum daily loads occurs mid-day instead of overnight as it was in previous years, principally being due to the addition of rooftop PV systems (averaging capacity increments of 25 MW per month). On the other hand, when comparing the FY2026 load profile with previous years, a slight increase in load is observed during the early hours of the day, followed by a modest decrease in average load during peak hours.

Figure 2-10: Comparison of Historical FY2024 & FY2025 Hourly Load Profiles with Base Case Forecasted FY2026



As is the case in the electricity industry worldwide, demand patterns in Puerto Rico will continue to change moving forward. On one hand, initiatives such as energy efficiency plans, demand reduction programs, expansion of BTM generation, development of local microgrids, and other factors are likely to reduce overall System Load. On the other hand, emerging trends such as the adoption of electric vehicles (EVs) have the potential to increase System Load. Growth in customer adoption of PV is expected to reduce mid-day System Load while potentially increasing evening loads and overnight hours. This shift in electricity demand patterns between hours of the same day highlights the potential role of energy storage as an asset class that can significantly improve the resource adequacy of the Puerto Rico electricity grid. Accordingly, continued improvements in understanding customer electricity demand patterns, especially identification of the key drivers and specific hours of high System Load, will be important for future resource adequacy planning.

2.2.2 Demand Response Programs

As electricity supplies worldwide become more reliant on intermittent renewable energy sources such as solar photovoltaics (PV), demand response (DR) becomes a topic of increasing importance. Whereas power generation and BESS are supply-side resources, DR is a demand-side resource, reducing electricity consumption from customers as called upon by utilities.

Most active DR programs are based on an economic inducement: offering customers a price sufficiently attractive to reduce their electricity consumption, but at a price lower than the prevailing wholesale market price that electricity customers are unable to access, thus providing a profit margin for the agent that initiated the transaction. Because they improve market efficiency, economic DR transactions reduce the aggregate cost of electricity service to all customers.

Whereas DR programs have grown on the mainland U.S. for 20 years, the history of DR in Puerto Rico is much more recent and therefore limited. Before LUMA assumed responsibility for the operation of the island's electricity system in June 2021, there appears to have been no activity to develop DR programs in Puerto Rico. After LUMA assumed operational responsibility for the Puerto Rico electricity system, given the persistent generation shortfalls that the system experiences, the highest priority for DR is to reduce resource inadequacy rather than to improve economic efficiency.

Accordingly, LUMA's DR efforts to date have focused on emergency DR program development rather than economic DR program development. In June 2022, LUMA proposed the Customer Battery Energy Sharing (CBES) pilot program to test the ability for energy stored in battery energy storage systems (BESS) sited at households to be discharged and aggregated by third-party vendors into a "virtual power plant" (VPP) for supplying the LUMA-operated electricity grid. A program of this design does not necessarily reduce the customer's electricity demands (which can continue unaltered to be served by the customer's BESS), but it does reduce demand on the electricity grid in the same way that traditional DR programs do.

After approval by the Energy Bureau, the CBES pilot program was launched in November 2023, growing to nearly 8,000 customers. Based on its success, and in the wake of the March 2025 release of LUMA's interim resource adequacy assessment indicating high vulnerability to many generation shortfalls during summer 2025, CBES was expanded in July 2025 to a much larger number of customers with BESS, enabling the provision of approximately 50 MW of VPP supply to the Puerto Rico grid for over 3 hours during the evening.

For this resource adequacy study, which covers the period through June 30, 2026, the CBES program in its current form and extent is assumed to be in effect, available to provide on any evening 50 MW of capacity – equivalent to about 1.6% of Puerto Rico peak electricity demand – for up to 4 hours.

2.3 Puerto Rico Capacity Reserves

Generation capacity reserves are capacity resources that are not currently serving System Load but could be quickly used to serve System Load if necessary to respond to system condition changes, such as the unexpected loss of a power plant or transmission line. This section of the report discusses how generation reserves are managed in Puerto Rico to operate the electricity system. Generation capacity reserves are categorized into Operating and Contingent reserves. The time required to supply power online is the main distinction between these two categories of reserves: Operating Reserves are available to supply online generation within 10 minutes or less, while Contingent Reserves supply online generation from 10 minutes up to 30 minutes. As a result, the estimation of Operating Reserves – subtracting Load from Generation Availability – on an hour-by-hour basis is at the core of resource adequacy analysis.

Operating Reserves are actively managed and maintained by the system operator to address very short-term fluctuations in electricity supply and demand. Within the designation Operating Reserves, there are two categories of reserves within which power plants are running even though they are not serving System Load: Spinning Reserves and Controlled Reserves. **Spinning Reserves** are generators that are already synchronized with the grid and can immediately increase their output to meet sudden changes in demand or compensate for unexpected generator or transmission line outages. **Controlled Reserves** are used to balance the supply and demand of electricity in real-time and maintain the stability of the grid.

Based on the above, the amount of generating capacity required to be online at any instant equals the sum of (1) System Load at that moment, plus (2) Controlled Reserves, plus (3) Spinning Reserves. The sum of Controlled Reserves plus Spinning Reserves, therefore, represents the capacity reserves that can instantaneously be tapped as needed to maintain reliable grid operations.

System operations policies in place for Puerto Rico state that the Controlled Reserves should be maintained to at least 300 MW and the Spinning Reserves should be set equivalent to the net dependable capacity of the largest generation unit being dispatched at the time. Given that the largest plant online is often on the order of 250-350 MW – note that Aguirre 1, Aguirre 2, Costa Sur 5 and Costa Sur 6 all have net dependable capacity ratings in that range – it is useful for the purposes of simplicity to consider the target Operating Reserve margin to be 650 MW (= 300 MW Controlled Reserves + 350 MW Spinning Reserves). This level of capacity reserves has been deemed by the system operator to be important for maintaining grid stability and reliability, as this level of reserves ensures that there is always enough surplus generation capacity online to be able to respond to sudden changes in system conditions without triggering interruptions in electricity service.

There are many days in which Operating Reserves in Puerto Rico fall below 650 MW. The System Operator is able to avoid initiating load-shedding on many of those days. When Operating Reserves decline below 650 MW, the risk of load shedding increases. When Operating Reserves fall below zero, load shedding becomes unavoidable.

The preceding discussion is provided as background to illuminate the importance of adequate capacity reserves above and beyond the level of systemwide electricity demand in ensuring the reliability of electricity service under virtually any conceivable condition that might arise during any of the 8,760 hours of a given year. With this background, it is possible to begin considering the appropriate level of capacity reserves to achieve resource adequacy.

In terms of resource adequacy, the capacity reserves being modeled are purely based on the difference between the available system capacity and the System Load at every hour. Given this, it can be said that this capacity reserves being considered are the operating reserves. These modeled capacity reserves are discussed further in Section 3.1.2.

2.4 Load Shed Events in Puerto Rico

Load shedding is the intentional, controlled interruption of the electrical supply to balance supply and demand when generating capacity is insufficient to meet load. In a resource adequacy context, this action is a last resort to prevent cascading failures that result in widespread blackouts and serves as a critical indicator of system vulnerability during periods of high demand, generator outages, or other resource shortfalls. An assessment of historical and potential load shedding events is therefore central to evaluating the adequacy of a power system and identifying potential reliability risks.

A technique used to avoid activating load sheds is the Voltage Reduction (VR) practice, which occurs when the system demand is higher than instant available generation. Instead of disconnecting customers, operators reduce the system's voltage to reduce demand. VR allow customers to stay connected and gives time to increase system generation to match demands by using the available reserves and/or emergency generation.

In Puerto Rico power system operations, load shedding is categorized into three primary types based on the trigger and execution method: Manual Load Shedding (MLS), Under-Frequency Load Shedding (UFLS), and Contingency Load Shedding (CLS).

- **Manual Load Shed (MLS)** – This type of load shedding is a controlled response to a generation shortfall, where demand exceeds the available supply. System operators manually or remotely trigger switches to disconnect designated areas in a rotating fashion. This ensures power interruptions are equitably distributed among consumers, with specific zones experiencing outages for predetermined durations.
- **Under-Frequency Load Sheds (UFLS)** – UFLS is an automatic and autonomous process designed to maintain grid stability. It activates when the system's frequency drops below a predefined normal operating range. Predetermined blocks of customers are automatically disconnected in stages without human intervention, stabilizing the grid's frequency and preventing a total system collapse. This is particularly crucial for grids that rely heavily on variable renewable energy sources.
- **Contingency Load Sheds (CLS)** – CLS involves manual intervention by operators and is used in various critical scenarios, such as when UFLS is insufficient to restabilize the system quickly. Operators manually disconnect customers to address increasing frequency fluctuations or other instability risks, preventing potential system failure on both the grid and generators.

The Resource Adequacy focuses solely on generation shortfall events (Manual Load Sheds), which reflect the capability of the system to meet Demand. The other two types of load sheds (Under-Frequency Load Sheds and Contingency Load Sheds) also represent inadequacies in the generation supply of the electricity system that cause load-shedding, but since these inadequacies are operational in nature rather than insufficiency of supply, they are not reflected in resource adequacy assessments.

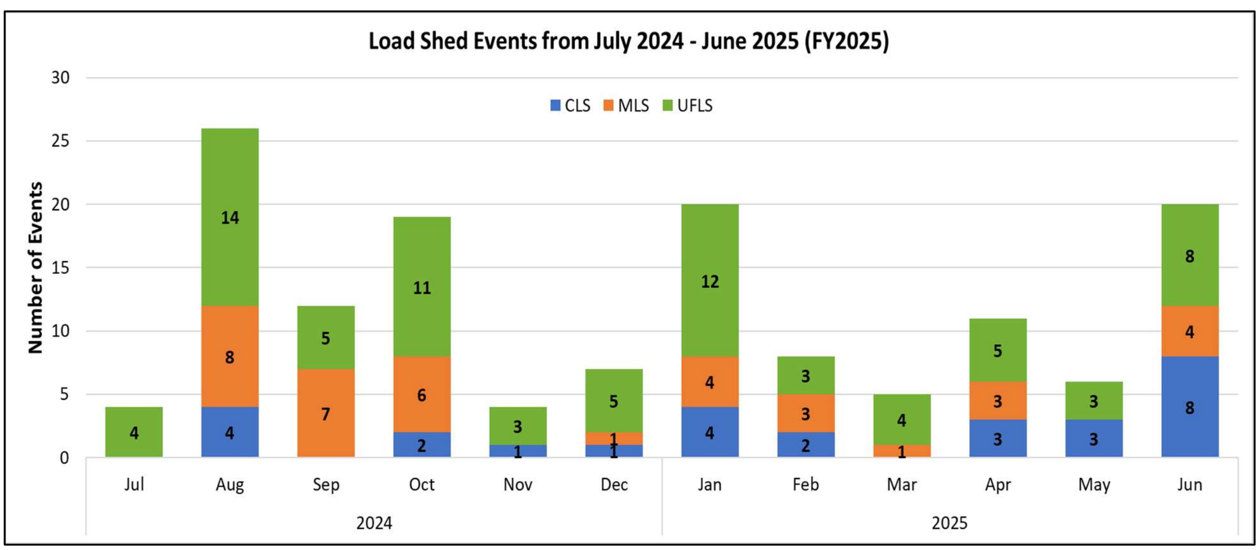
As indicated below in table 2-1, approximately 26% of the load-shedding events in FY2025 were MLS events caused by generation shortfalls, having an average duration of at least 3 hours and affecting approximately 103,000 clients per event. On the other hand, approximately 54% of the load shed events in FY2025 were due to UFLS events. Most of these UFLS events were not caused by generation shortfalls but instead were caused by trips (i.e., unexpected outages) of generation units, creating a sudden and significant imbalance in generation supply and customer demand that causes grid frequency to deviate from acceptable levels. On average, these events are much shorter in duration than MLS events, averaging 22 minutes in duration and affecting approximately 139,000 clients per event. Finally, CLS events have been more common this last fiscal year with a contribution of 20% of the total load shed events. Although CLS events last longer than the UFLS, they are generally shorter than MLS events and affect fewer customers. It should also be emphasized that Table 2-1 presents only load shed events driven by generation-related issues, and therefore customer service interruptions due to disturbances on the transmission and distribution network are not included in Table 2-1.

Table 2-1: Summary of Puerto Rico Load-Shed Events in FY2025

Type of Load Shed	Number of Events	Average Duration (minutes)	Average Customers Affected
MLS	37	208	103,095
UFLS	76	22	138,672
CLS	28	44	35,136

Figure 2-11 below illustrates the number of load shed events, throughout FY2025, categorized by type and distributed by month. Notably, August 2024 recorded the highest number of load shed events, primarily due to multiple operational issues in the generating units, compounded by peak electricity demand in during that month. In contrast, the spike in January 2025 can be attributed to the residual effects of the New Years Eve blackout. Both CLS and MLS events remained relatively consistent month to month, with a marked increase in CLS events in June 2025, when eight incidents were recorded. Excluding the January outlier, the data suggests that seasonal or system-specific stressors, particularly during the summer months, may be influencing the frequency of load shedding.

Figure 2-11: Historical Load Shed Events for FY2025



As previously described, insufficient capacity to meet demand triggers an MLS event. In contrast, UFLS events are not triggered by capacity shortfalls, but rather by sudden disturbances that compromise frequency stability in the bulk power system. CLS events are typically initiated when UFLS alone is insufficient to restore system stability. Therefore, while LOLE derived from resource adequacy analysis can serve as a predictor for the expected number of MLS events in a given year, it does not predict the occurrence of UFLS or CLS events.

2.5 Upcoming Utility-Scale Resources

LUMA is actively collaborating with all stakeholders on initiatives involving utility-scale resources that aim to be interconnected with the transmission and distribution (T&D) system. Before being interconnected, studies must be completed, regulatory approvals must be obtained, and the contract between PREPA and the developer must be executed. LUMA collaborates with developers to interconnect various technology types alongside renewables to provide flexibility to the T&D system, including Battery Energy Storage Systems (BESS), Thermal Power Plants, and hybrid Thermal or Solar projects paired with BESS.

To date, various regulatory, planning, and procurement challenges have delayed deployment. Note that LUMA is currently processing an interconnection queue of approximately 36 utility-scale projects (2,800 MW) with regulatory approvals, with an additional 30 initiatives (1,936 MW) in the pipeline. For more details on the upcoming utility-scale projects, refer to Appendix D.

2.5.0 Solar Power Plants:

- The current procurement efforts underway in Puerto Rico (Ciro One, Xzerta, Tranche 1 & Tranche 2) for new solar energy projects intend to add 1,145 MW.

2.5.1 Energy Storage Systems:

- The current procurement efforts underway in Puerto Rico (ASAP SO1 & SO2, Tranche 1 & Tranche 2, Tranche 4, LUMA 4X25 & GENERA PR BESS) for new BESS plan to add 2,289 MW.

2.5.2 Thermal Power Plants:

- The current procurement efforts underway in Puerto Rico (GENERA PR Peakers & Energiza) for new thermal power plant projects intend to add 722 MW.

An interesting energy storage technology to explore further is flywheels. These systems store electrical energy in the form of mechanical energy, which can then be dispatched to stabilize the system's electrical frequency and provide short-duration energy backup. This technology is typically used for **short-duration, high-power applications** like frequency regulation, and it's less common in utility-scale renewable integration projects like those in Puerto Rico.

Table 2-2 Upcoming Utility Scale Resources

Programs	Projects by Programs	Approved & Executed Contracts (MW)	Proposed Additions (MW)
Accelerated Storage Addition Program (ASAP) - Standard Offer 1	6	0	188
Accelerated Storage Addition Program (ASAP) - Standard Offer 2	13	0	654
Genera PR BESS	6	430	0
Genera PR Peaker Replacement	4	244	0
LUMA 4X25	4	0	100
Non-Tranche	3	200	77
Other-High Voltage Distribution Cable	1	0	500
P3A RFP	1	478	80
Tranche 1	20	1278.8	479.3
Tranche 2	3	126.07	0
Tranche 4	1	50	0
Grand Total	**62**	**2806.87**	**2078.3**

Most of the projects outlined in this section are still in the early stages of development and are unlikely to become operational within FY2026. As such, they are not included in the Base Case modeled in this assessment. However, to reflect the potential for enhanced resource adequacy in the coming years as new resources are brought online, several of the sensitivity analyses conducted as part of this resource adequacy assessment incorporate many of the utility-scale resources described above. These analyses aim to evaluate their potential future impact on the reliability of the electricity system.

3.0 Resource Adequacy Analysis Results and Implications

Resource adequacy analyses for the Puerto Rico electric system were conducted using the Probabilistic Resource Adequacy Suite (PRAS), a set of simulation tools developed by the U.S. National Renewable Energy Laboratory (NREL) and adapted specifically for Puerto Rico's grid as PRAS-PR. A comprehensive validation of the PRAS model is documented in Appendix 7 of LUMA's *FY2023 Puerto Rico Electrical System Resource Adequacy Analysis* report[9]. (For a more detailed explanation of the resource adequacy methodologies used, see Appendix C of this report.)

In this study, PRAS-PR was used to quantify the resource adequacy of Puerto Rico's existing electricity system, establishing a baseline set adequacy metrics to inform future planning decisions. Using PRAS-PR, hourly simulations of electricity supply and demand for FY2026 were conducted to assess whether available generation capacity could meet System Load in each of the year's 8,760 hours.

Because power plant forced outages occur randomly, a Monte Carlo analysis was performed. Each hour of FY2026 was simulated 2,000 times, with each simulation representing a unique "random draw" of available generation based on the probability of operational availability for each power plant. This approach allows for a probabilistic assessment of whether generation is sufficient or insufficient in each hour. By aggregating the results across all simulations, the model produces a probabilistic summary of resource adequacy for each hour, which is then extended across the full year to provide a comprehensive view of system reliability under uncertainty.

In the following section, the Base Case resource adequacy results for the Puerto Rico electricity system are discussed in detail. This is followed by a review of multiple sensitivity analyses for FY2026, which explore how changes in electricity supply or demand, relative to Base Case assumptions, could affect resource adequacy. Full descriptions and results of all resource adequacy analyses are presented in Appendix A.

3.1 Base Case Resource Adequacy Results

The Base Case analysis reflects an assessment of generation resource adequacy that can reasonably be expected from the Puerto Rico electricity grid during FY2026. It reflects assumptions regarding both the projected electricity demand across the system and the generation capacity anticipated to be available for system operators to meet that demand.

As discussed in Section 2.2.1, demand assumptions are derived from the hourly load shape observed in 2024, adjusted to account for abnormal weather conditions that unusually influenced demand that year, as well as the expected addition of DG and CHP resources in FY2026.

[9] LUMA Energy. (2022). Motion to Submit LUMA's Resource Adequacy Study Subject: Filing of Resource Adequacy Study prepared by LUMA. https://energia.pr.gov/wp-content/uploads/sites/7/2022/09/Motion-to-Submit-Lumas-Resource-Adequacy-Study-NEPR-MI-2022-0002.pdf

On the supply side, the Base Case includes both existing installed generation and new solar and BESS projects anticipated to come online during the fiscal year. Appendix B provides more detail about the supply assumptions made for the Base Case.

To maintain a conservative approach consistent with prior resource adequacy reports, the analysis assumes that one of the legacy thermal plants (Palo Seco 3, 170 MW) will be unavailable for the study period. In addition, Aguirre 1 is considered out of service for the entire year as its Estimated Return Time (ETR) is projected to occur after the end of FY2026. This is discussed further in Appendix B.

From July to October 2025, the CBES+ demand response program is included as an additional resource, assumed to contribute an average of 50 MW during peak hours to help mitigate load shedding.

Lastly, the Base Case incorporates select solar and BESS additions expected in FY2026 as detailed in Table 3-1.

Table 3-1: Upcoming Projects for FY2026

Facility	Capacity (MW)	COD	Resource type
Ciro One (phase 1) Ciro One (phase 2)	90 50	Dec 2025 June 2026	Solar Solar
CFE Salinas Solar	120	April 2026	Solar
Yabucoa YFN	32.1	May 2026	Solar
CFE Salinas BESS (Phase 1)	100	April 2026	BESS

Using Base Case assumptions, Table 3-2 summarizes two key measures derived from the resource adequacy analysis: Loss of Load Expectation (LOLE) and Loss of Load Hours (LOLH). In addition to average values, the table also presents the minimum and maximum estimates for each metric. Based on the results, Puerto Rico could experience dozens of days with generation shortfalls and load-shedding events due to resource inadequacy during FY2026.

Table 3-2: Summary of LOLE and LOLH Statistics for Base Case

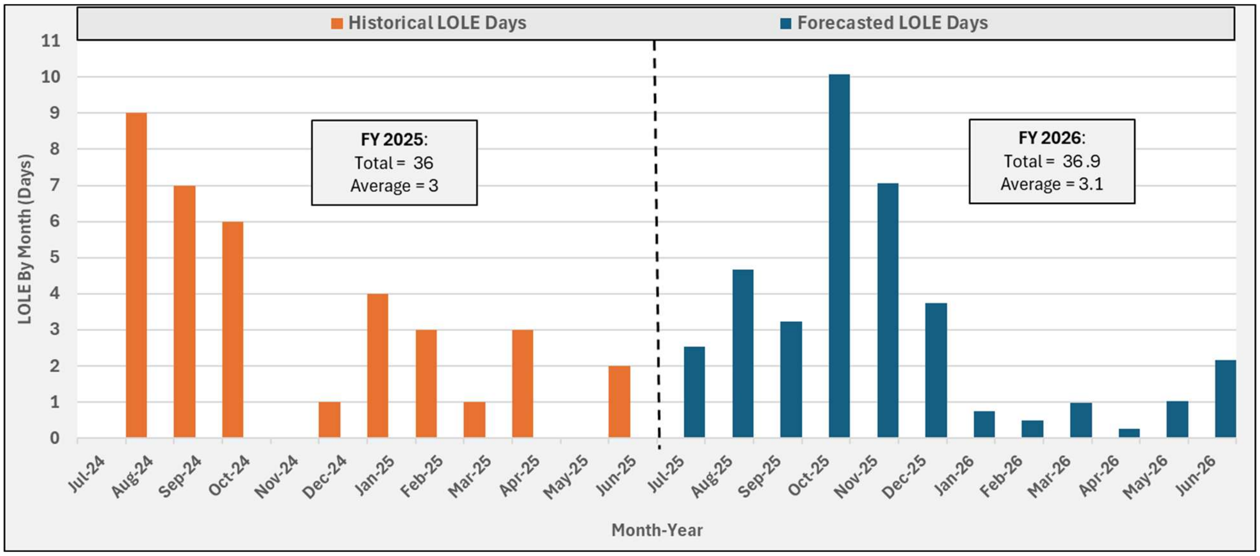
Measure	Loss of Load Expectation (LOLE)	Loss of Load Hours (LOLH)
Average	36.9 Days / Year	196.3 Hours / Year
Distribution Maximum	61 Days / Year	387 Hours / Year
Distribution Minimum	15 Days / Year	64 Hours / Year

3.1.0 Loss of Load Expectation

The Base Case estimated LOLE for FY2026 is 36.9 days per year, indicating that, on average, a generation shortfall (i.e., "loss of load") is expected to occur on approximately 36.9 separate days per year. This result is consistent with the FY2025 Base Case LOLE results of 36.2 days per year, largely because no significant new resources have been added since the deployment of the TM units in 2023.

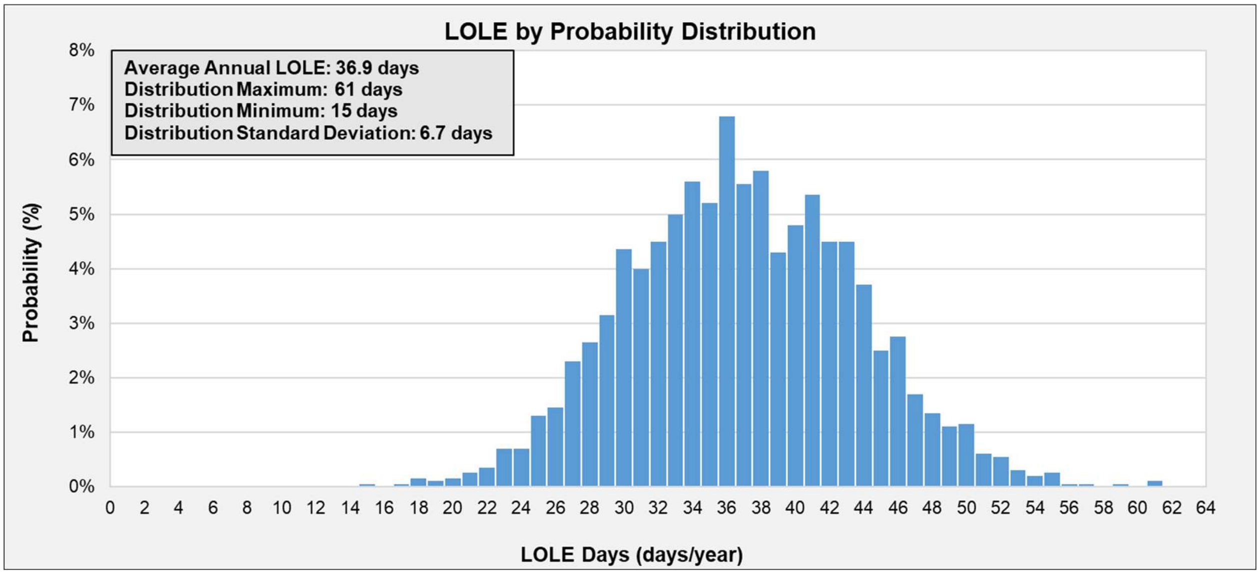
As shown in Figure 3-1, a LOLE of 36.9 days per year corresponds to an expectation of 37 MLS events annually, closely aligning with the 36 MLS events recorded in FY2025. When averaged across the year, this equates to just over 3 days per month in which a manual load-shed event due to generation shortfalls would be expected to occur.

Figure 3-1: Comparison of Historical FY2025 LOLE Versus Base Case Forecasted FY2026 LOLE



An estimated 36.9 days of loss of load represents the average or expected outcome for FY2026. However, it is equally important to consider the high standard deviation in the LOLE results. Across the thousands of Monte Carlo simulations conducted, none produced an LOLE estimate below 15 days per year, while some scenarios projected up to 61 days of load-shed events annually. Figure 3-2 below illustrates the distribution of estimated LOLE outcomes from the Monte Carlo simulations, providing a clearer picture of the potential spread in reliability outcomes for FY2026.

Figure 3-2: Base Case Loss of Load Expectation Probability Distribution



Several inherent and inherited characteristics of the Puerto Rico electricity system help explain the high average and wide distribution in estimated LOLE outcomes:

- Existing thermal power plants represent over 90% of available generating capacity in Puerto Rico, and their forced outage rates are very high relative to electricity industry norms. As a result, not only do power plants break down frequently, but multiple power plants often are unavailable at the same time. With power plant outages, there is a significant risk that there will not be enough remaining generation capacity available to serve System Load.

- In addition, due to being past their useful life and in poor condition, thermal power plants in Puerto Rico often require prolonged planned maintenance outages, thus reducing the number of hours in a year during which they can be operated.

- When a power plant goes offline, the system operator must increase output from the power plants that remain online to meet System Load. This places additional stresses on those power plants, resulting in a higher incidence of forced outages or longer downtime for them when undertaking planned maintenance later.

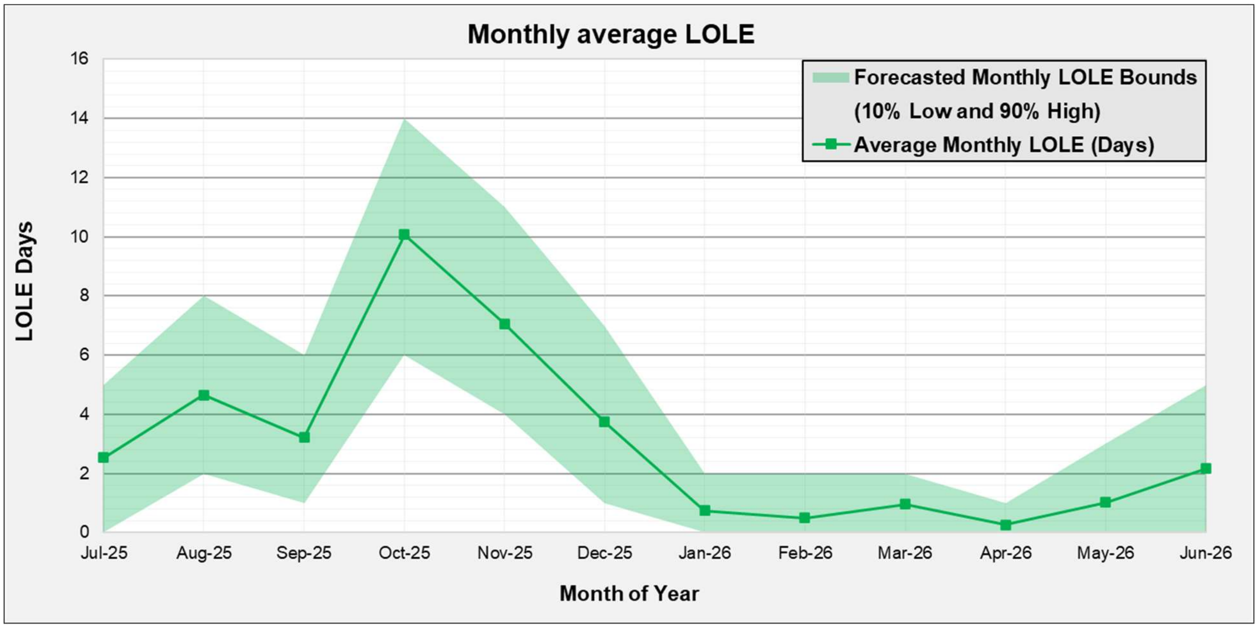
- Puerto Rico is unable to import electricity from neighbors, and the system operator has control over only a few dozen power plants to generate electricity. By comparison, due to being electrically interconnected with each other, utilities on the U.S. mainland have access to hundreds of power plants that can be started or ramped up to meet load.

- In Puerto Rico, the sudden loss of a single large power plant that is online -- such as the Aguirre Steam units or the Costa Sur units, all of which are in the 300-350 MW dependable capacity range -- immediately reduces the total available generating capacity on the system by roughly 8%. A loss of 8% of available capacity with just one power plant outage is challenging for a system operator to accommodate, especially when most other power plants are already being fully utilized and any power plants not currently online are either unavailable or highly unreliable.

In contrast, the unexpected loss of even the largest power plant on the U.S. mainland is much more manageable because of the larger pool of generation resources that can be tapped.

Figure 3-3 shows the estimated LOLE for the Base Case by month. The green line represents the average estimated LOLE, while the shading around the middle line represents the calculated monthly LOLE distribution's 10% low and 90% high values for each month.

Figure 3-3: Base Case Calculated Loss of Load Expectation by Month



For example, for July 2025, the estimated average LOLE was approximately 3 days, with the worst 10% of simulations having 5 days of LOLE, while the best 10% of simulations had 0 LOLE days. As a result, one might expect LOLE for July 2025 to fall somewhere between the range of 0 days to 5 days, with 3 days being the most likely outcome.

Estimated LOLE was found to be highest from July through December. From July through September, System Load is higher because of high heat and humidity, driving increased customer demand. Meanwhile, from October through December, some generators schedule planned maintenance outages during this period. For most other utilities in the U.S., generator reliability is sufficiently good that maintenance outages can be scheduled during months of low electricity demand, so that most/all capacity is available during peak months. However, because of the high forced outage rates and the long average outage durations associated with Puerto Rico's thermal power plant fleet, there is minimal scheduling flexibility for maintenance planning: any plant that is not broken down has a reasonable chance that it will be called upon by the system operator to generate electricity. Unfortunately, multiple thermal power plants are unavailable during most hours of the year in Puerto Rico, even during the hottest summer months when maximum generation fleet availability is most desirable.

3.1.1 Loss of Load Hours

The estimated LOLH in the Base Case is 196.3 hours, implying that Puerto Rico electricity customers should expect, on average, approximately 196.3 hours of loss of load during FY2026, in which generation resources will be deficient.

While the estimated LOLH for the Base Case is 196.3 hours, note that in any one simulation, LOLH varied between a minimum of 64 hours and a maximum of 387 hours. A histogram of the distribution of estimated LOLE outcomes from the 2,000 simulations is presented below in Figure3-4.

Figure 3-4: Base Case Loss of Load Hours Probability Distribution

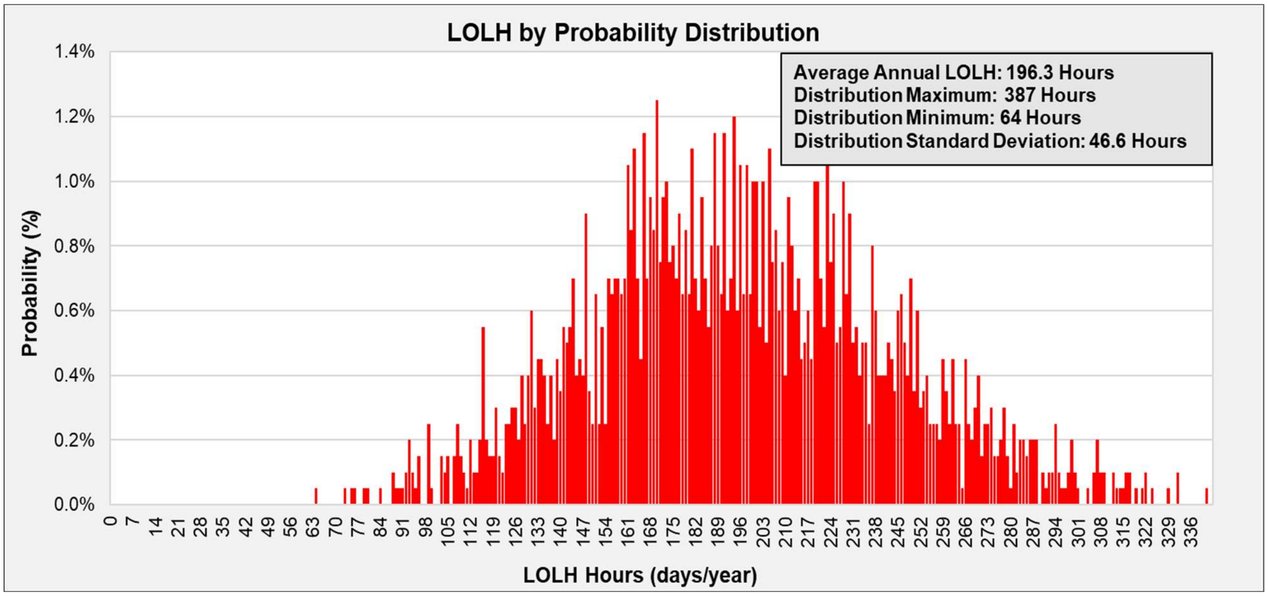
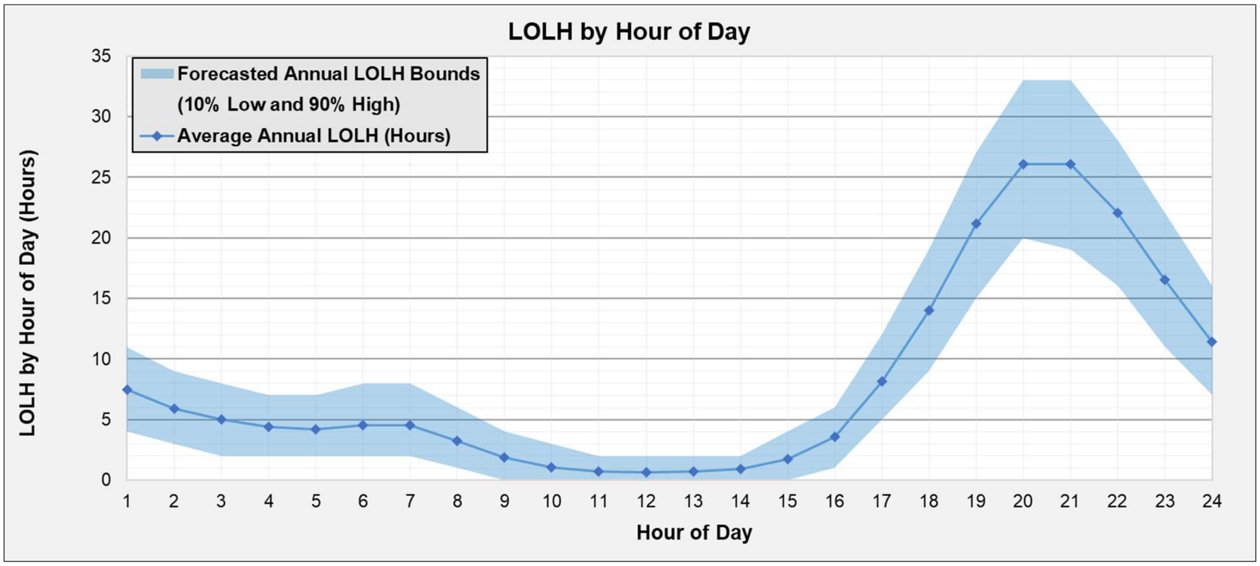


Figure 3-5 presents the average number of LOLH (for all the 2,000 simulations), broken out by hour of the day. Similar to the monthly LOLE presented in Figure 3-3 the shading represents the calculated annual LOLH distribution's 10% low and 90% high values for each hour. The majority of LOLH are observed during the evening hours, when Reserves reach their minimum levels because System Load is highest and solar production is diminished or unavailable. Approximately 70% of the observed LOLH in the resource adequacy simulation was found to occur between 6:00 p.m. and 12:00 a.m.

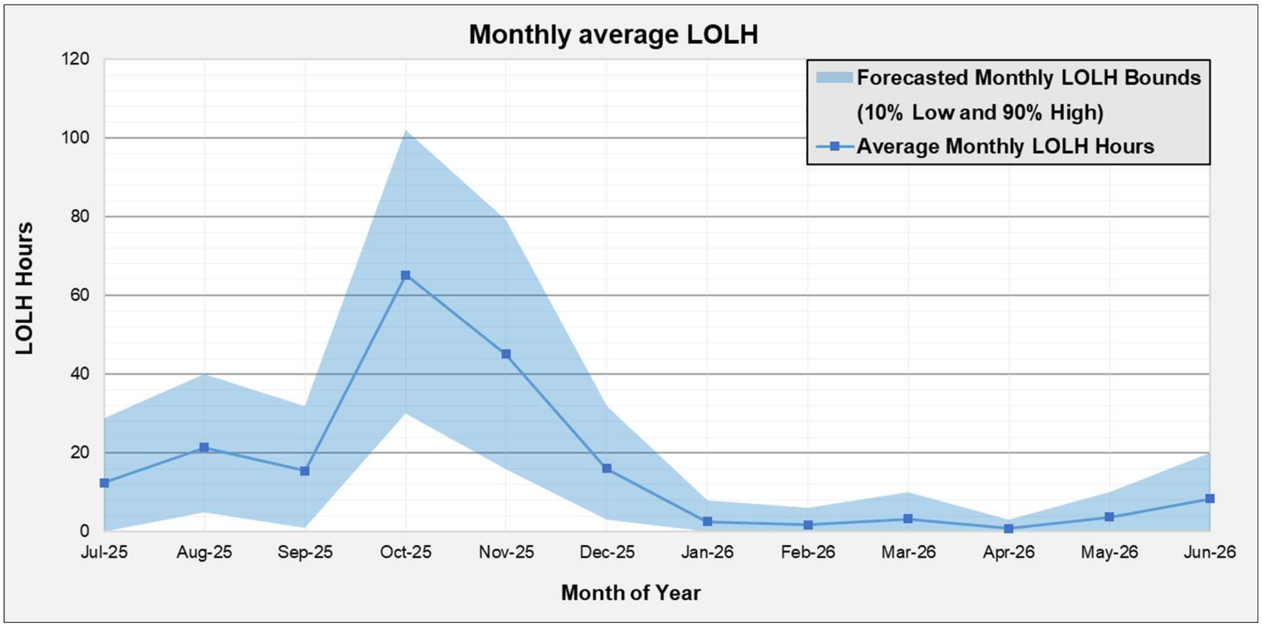
Figure 3-5: Base Case Calculated Loss of Load Hours by Hour of the Day



From the perspective of improving system resource adequacy, the above results indicate that the most effective solutions will be those targeted at being able to help meet load during the evening peak. For example, the addition of solar-only electricity generation helps system resource adequacy only during hours when the sun is up, which reflects just almost a third of the hours when the simulated LOLH were found to occur. As such, the results in Figure 3-5 illustrate why additional solar-only generation will have little impact on improving resource adequacy in Puerto Rico. If a generation shortfall event 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 would not provide much help in preventing load-shed from occurring in the evening.

Figure 3-6 below presents the monthly distribution of LOLH for the Base Case assessment. Consistent with the LOLE trends shown in Figure 3-5, LOLH peaks in October and November. This is primarily due to the concentration of planned outages during these months, which coincide with elevated system load levels. Additionally, maintenance outages of large generators contribute to increased LOLH risk, as any concurrent forced outages during these periods can further reduce system reliability. The shaded areas in the graph represent the 10th and 90th percentiles of the monthly LOLH distribution, illustrating the range of potential outcomes for each month.

Figure 3-6: Base Case Calculated Loss of Load Hours by Month of the Year



3.1.2 Capacity Reserve Margins

Figure 3-8 illustrates the average system capacity reserve margins estimated for FY2026 in the Base Case, presented by hour and month. These values represent the average of the probability distribution across all simulation runs. Each value in the figure reflects the average MW of available capacity reserves during that specific hour and month.

Available capacity reserves are calculated as the available capacity of the system minus the System Load. The figure uses heat maps to visualize reserve levels, with a gradient color scale to indicate reserve levels. Green signifies reserves exceeding 650 MW. As reserve levels decrease toward this threshold, the color transitions from green to yellow, and eventually to red as reserves approach zero. Deeper red tones indicate lower available reserves levels. Black cells represent negative reserves, signaling a generation shortfall where system load exceeds available capacity, conditions under which LOLE and LOLH events occur.

These dynamics are further illustrated in Figure 3-7, which provides a clear depiction of reserve adequacy throughout the assessment period.

Figure 3-7: Reserves Heat Map Gradient Coloring Methodology

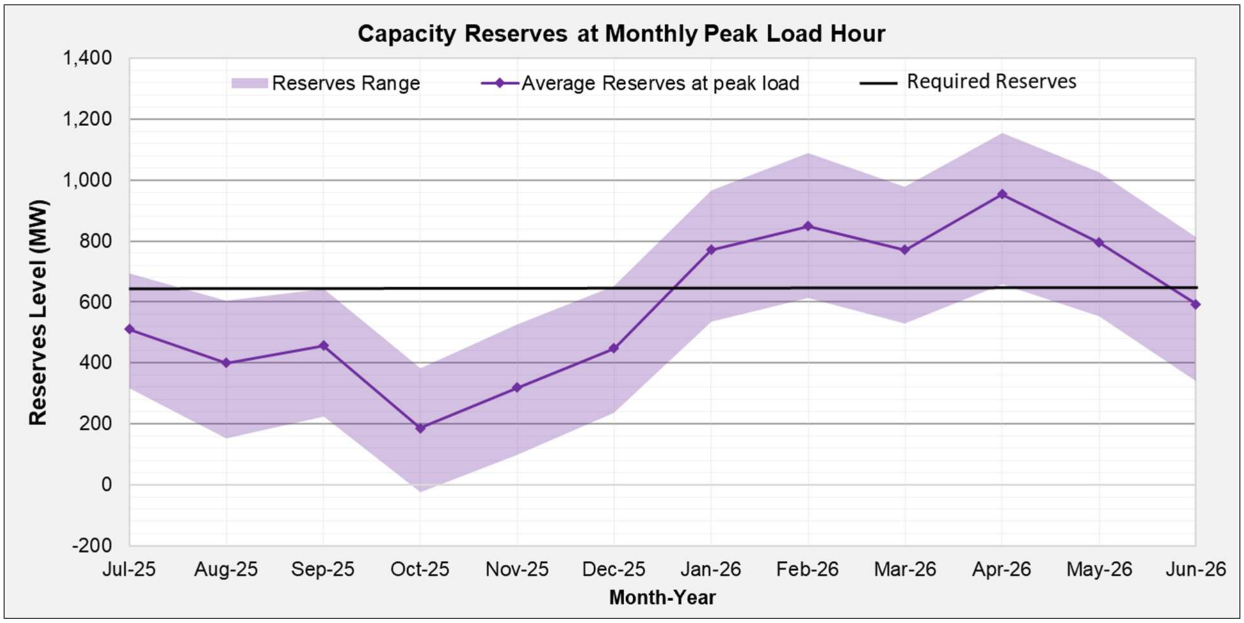
Figure 3-8 below displays the average hourly capacity reserve margins by month for the Base Case. As will be shown in some of the sensitivity scenarios, certain hours in specific months exhibit zero or negative reserve levels, represented by black cells, indicating that LOLE and LOLH events are forecasted to occur on an average day during those months. Although no black cells appear in Figure 3-8 for the Base Case on a monthly average basis, a more detailed, day-by-day analysis during the most critical months would reveal black cells on certain days, indicating negative reserves.

Figure 3-8: Base Case Capacity Reserve Margins by Hour and Month

Hour of Day	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Average by Hour
1	689	714	725	473	507	753	1,088	984	1,041	1,274	1,132	889	**856**
2	743	779	764	530	514	823	1,162	1,016	1,101	1,354	1,224	969	**915**
3	767	846	792	563	517	877	1,222	1,048	1,151	1,415	1,299	1,021	**960**
4	782	886	812	591	529	912	1,264	1,074	1,183	1,457	1,340	1,064	**991**
5	789	908	819	602	531	921	1,267	1,078	1,193	1,466	1,367	1,087	**1,002**
6	783	892	812	585	521	884	1,219	1,046	1,160	1,412	1,348	1,080	**978**
7	793	910	827	576	526	837	1,152	1,034	1,137	1,402	1,366	1,108	**972**
8	815	953	891	639	593	872	1,184	1,081	1,199	1,505	1,444	1,190	**1,030**
9	860	1,016	979	727	686	995	1,288	1,200	1,351	1,661	1,597	1,339	**1,142**
10	918	1,092	1,067	802	773	1,139	1,435	1,341	1,491	1,646	1,575	1,320	**1,217**
11	966	1,161	1,114	841	843	1,245	1,539	1,427	1,588	1,753	1,685	1,437	**1,300**
12	991	1,189	1,134	842	858	1,286	1,599	1,491	1,627	1,790	1,738	1,491	**1,336**
13	998	1,198	1,129	836	844	1,291	1,630	1,532	1,657	1,788	1,723	1,452	**1,340**
14	972	1,155	1,081	777	807	1,253	1,602	1,510	1,633	1,750	1,625	1,384	**1,296**
15	922	1,063	972	662	738	1,134	1,527	1,439	1,542	1,787	1,604	1,407	**1,233**
16	850	928	823	515	650	948	1,358	1,335	1,389	1,571	1,407	1,238	**1,084**
17	767	755	698	370	500	723	1,139	1,203	1,170	1,349	1,189	1,057	**910**
18	691	615	595	277	402	584	967	1,044	972	1,192	1,026	886	**771**
19	621	517	507	207	328	462	832	920	860	1,064	911	731	**663**
20	539	424	456	186	318	448	771	849	772	954	804	628	**596**
21	511	399	457	194	334	467	790	864	771	968	795	594	**595**
22	534	437	492	236	358	505	831	884	801	1,007	829	626	**628**
23	577	504	562	315	411	578	901	915	871	1,053	886	684	**688**
24	627	604	645	402	461	668	994	949	951	1,165	1,009	773	**771**
Average by Month	**771**	**831**	**798**	**531**	**565**	**858**	**1,198**	**1,136**	**1,192**	**1,408**	**1,289**	**1,061**	

Figure 3-9 presents the forecasted reserve capacity in megawatts (MW) for the Base Case at the peak load hour of each month. These values are compared to required reserve levels (as described in Section 2.3) that average approximately 650 MW (black line).

Figure 3-9: Base Case Capacity Reserves at Monthly Peak Load Hour



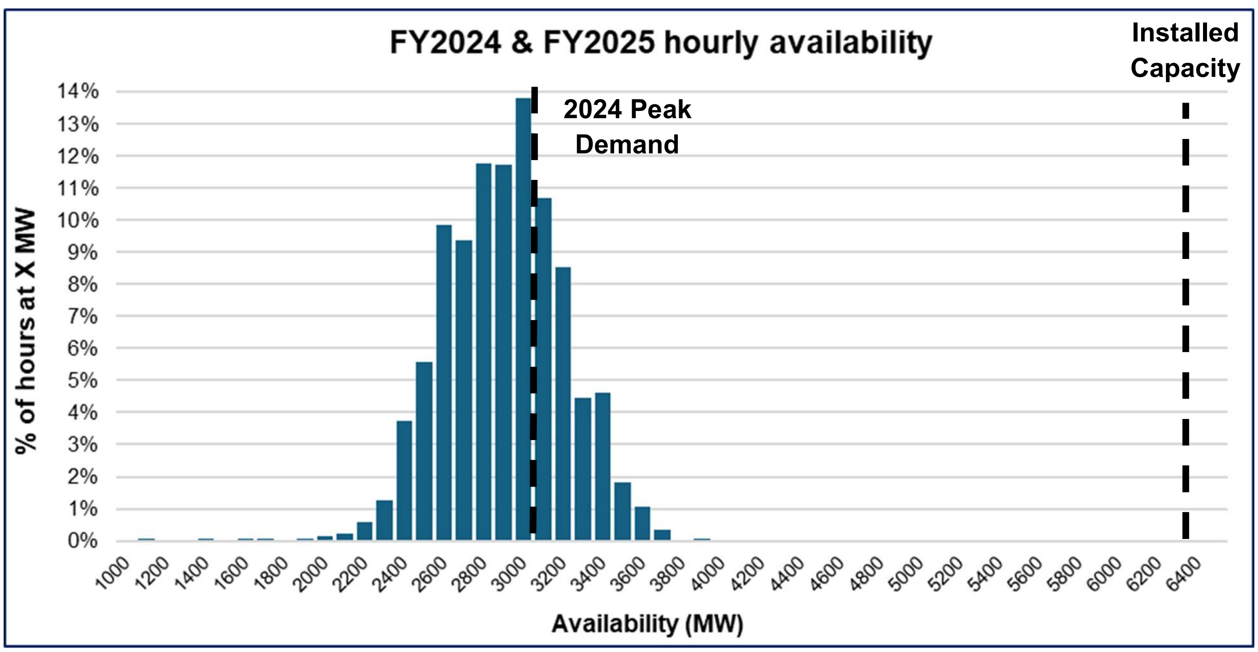
The shaded area of the graph represents the probability distribution between iterations of the probable reserves at peak load hour each month. For example, in October, the forecasted average reserve capacity level at peak load hour is roughly 200 MW, with a probable lowest amount below 0 MW, and a probable maximum of 380 MW. From August to December 2025, even the probable maximum reserve capacity levels at peak hour are lower than the ~650 MW of capacity that LUMA's reserve policy has set as its standard to assure acceptable system reliability. This is a clear illustration of the degree of resource inadequacy that Puerto Rico's electricity system faces.

3.1.3 Available Capacity

As explained in section 2.1, Puerto Rico's installed capacity is approximately 6,300 MW: however, when accounting for power plant retirements, output limitations and outages, the actual available capacity in any hour of the year averages around 3,000 MW. This significant gap is due primarily because that many generation units have exceeded their expected useful life, coupled with prolonged underinvestment in maintenance, resulting in more frequent, and often longer, outages.

As shown in Figure 3.10, the distribution of all hourly availability from FY2024 through FY2025 indicates that, for most hours, available capacity in Puerto Rico has ranged between 2,400 MW and 3,400 MW. When compared to the approximately 6,400 MW of installed capacity, this reflects a shortfall of 2,000 MW to 3,000 MW of unavailable capacity. More detailed information regarding this unavailable capacity is provided in Section 2.1.

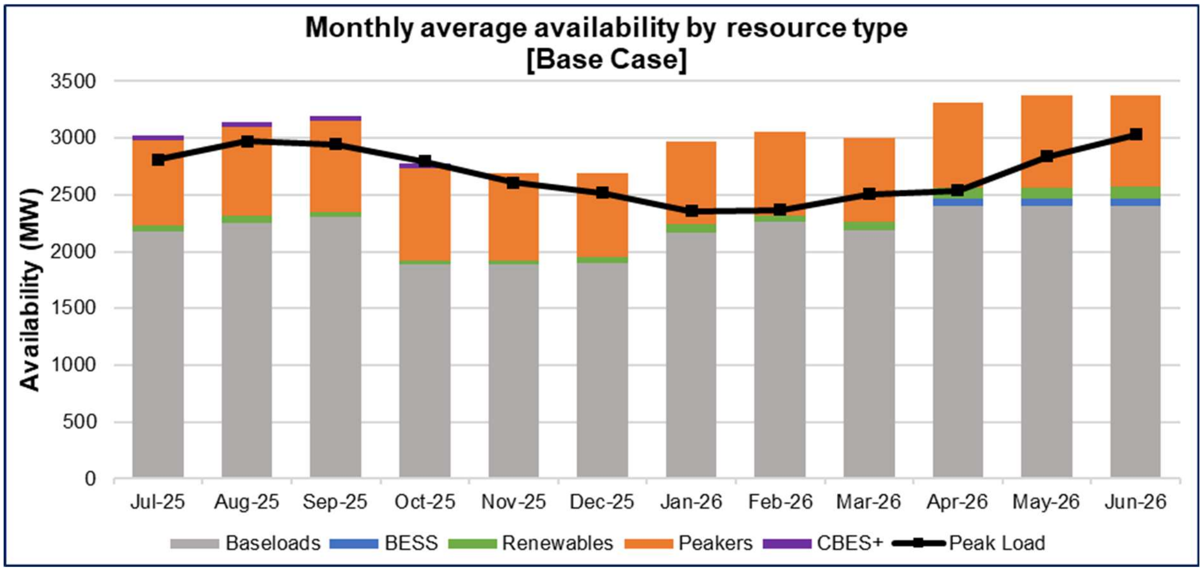
Figure 3-10: FY2024 & FY2025 Historical Average Availability



Based on the historical availability trends of Puerto Rico electric system units, Figure 3-11 presents a monthly forecast of average availability for the base case scenario, broken down by available resource type expected for each month of FY2026. The analysis shows that the total monthly average availability is expected to remain close to 3,000 MW, primarily due to the limited addition of new resources and the continued aging of the thermal generation fleet. The figure also highlights that the 2024 peak demand reached 3,184 MW, near equal to the average system availability, underscoring the system's vulnerability.

Resource availability has been categorized into baseload units, peakers, renewables, BESS and the CBES+ program, and is compared against the monthly forecasted peak load.

Figure 32-11: FY2026 Monthly Forecasted Average Availability



As shown in Figure 3-11, the forecasted peak load for October surpasses the expected average available capacity, aligning with the LOLE and LOLH results, which identify October as the month with the highest risk of load shedding. November follows closely, although average availability is slightly higher than peak demand, the margin is minimal, indicating elevated risk of load shedding. Planned and forced outages are the principal drivers of reduced available capacity, especially from October to December, when a significant number of baseload units are scheduled for maintenance. (See Appendix B for the planned outage schedule used in the base case).

3.2 Resource Adequacy Sensitivity Analyses

To evaluate how much resource adequacy of the Puerto Rico electricity system might be affected due to changes that might reasonably occur in electricity supply or demand and evaluate how future resources would benefit resource adequacy in Puerto Rico, this report presents the modeling results from 20 sensitivity analyses in which certain assumptions were altered from those used in the Base Case. Some of these sensitivity analyses reveal a worsening of resource adequacy, having either reduced resource availability assumptions or increased electricity demand assumptions. Conversely, other sensitivity analyses reveal improvement in resource adequacy, having either increased resource availability assumptions or reduced electricity demand assumptions.

Note that many of these sensitivities are unlikely to occur during FY2026. For instance, it is impossible that large quantities of new generation supplies will be available for the entirety of FY2026. Even if clearly implausible, such sensitivities were investigated to reveal the degree to which significant resource additions would affect resource adequacy in Puerto Rico if they were immediately available.

The following list summarizes each sensitivity and a brief description of the assumptions that each one contains:

- **Unavailability of upcoming projects for FY2026**: this sensitivity analyses the scenario assuming none of the new upcoming resources assumed for FY2026 in the Base Case enters online, which includes the CBES+ demand response program from July to October 2025, the addition of 3 new solar projects and the addition of one BESS project.
- **Unavailability of TM generators**: this sensitivity addresses the impact of not having the 340 MW of thermal units added most recently to the system (in 2023). The results of this sensitivity reveal that the absence of these TM generators would have a major negative impact on resource adequacy and much higher risk of load-shedding.
- **Unavailability of Costa Sur 6**: this sensitivity analyzes the impact of losing another big baseload unit for a full year, taking Costa Sur 6 as example. Due to an aging electric fleet, a scenario like this is possible to happen, taking as example the most recent outage of Aguirre 1 on February 2025, which is expected to be out at least 1 ½ years.
- **Unavailability of AES**: the impact of having both AES units out for a full year is analyzed. This sensitivity has the most impactful result of all sensitivities, reflecting the importance of this powerplant electricity system and highlighting the need for a reliable resource (or multiple resources) to substitute for AES availability when this powerplant retires.
- **Addition of future solar-only projects**: this sensitivity assumes adding all upcoming solar projects, which includes all the Tranche 1 solar projects (~745 MW), and two non-tranche projects (200 MW), with a total of approximately 945 MW of solar-only capacity. This sensitivity has a very small impact on LOLE, with a slightly more noticeable impact on LOLH.
- **Addition of ASAP BESS projects (SO1)**: this sensitivity addresses the addition of 6 BESS projects under the ASAP BESS program, totaling 188 MW of capacity. These resources are planned to charge energy during daytime (when system capacity reserves are higher), and dispatch their energy at peak hours, having a notable impact on resource adequacy.
- **Addition of ASAP BESS projects (SO1 & SO2):** like the previous sensitivity, this one includes the 6 projects from SO1, but also adds the 11 projects from SO2, for a total of 17 BESS projects and 762 MW of BESS capacity.
- **Addition of Genera BESS projects**: this sensitivity analyzes the addition of future Genera BESS projects, with a total of 430 MW of capacity.
- **Addition of LUMA 4x25 BESS projects**: this sensitivity considers a total of 100 MW from the LUMA BESS project.
- **Addition of Tranche 1 projects (solar & BESS)**: this sensitivity analyzes the impact of adding all the upcoming projects from tranche 1 (including all the solar and BESS projects) and the non-tranche upcoming solar projects, for a total of 945 MW of solar + 535 MW of BESS projects. This sensitivity resulted in a better resource adequacy improvement compared to the addition of 762 MW of ASAP SO1 & SO2 BESS projects because, as we add solar resources, capacity reserves during daytime increases, and hence that additional capacity could be used to charge more effectively the BESS and have their 100% availability for the peak hours.

- **Addition of Tranche 1 + ASAP (SO1 & SO2) + Genera BESS + LUMA 4x25 BESS projects**: this sensitivity considers having most of the future upcoming resources that are currently on-going procurement, totaling 945 MW of solar capacity + ~1,800 MW of BESS capacity. The addition of all these resources resulted in a LOLE close to the US Industry Standard, but still greater than 1 LOLE day. See Appendix A for more detail about the assumptions used in this sensitivity.

- **Addition of Energiza project**: this sensitivity analyzes the assumption of having the Energiza Combined Cycle (CC) project available during the entirety of FY2026, for a total of 478 MW of new thermal resource.

- **Addition of Genera peakers**: this sensitivity analyzes the addition of multiple future peakers procured by Genera, totaling 244 MW of new peaker capacity.

- **Load increase (+10%):** this sensitivity seeks the impact of a 10% load increase on all hours during FY2026, resulting in a considerable increase in LOLE and LOLH due to more required availability to supply demand.

- **Load decrease (-10%):** Like the load increase sensitivity, this sensitivity analyzes the opposite effect by reducing load on all hours during FY2026 by 10%, resulting in a great decrease on LOLE & LOLH.

- **Addition of Electric Vehicles Load (EVs):** this sensitivity analyzes the effect of adding the forecasted amount of consumption that EVs could add to the system, which equals to approximately 60 GWh for FY2026, and its effect on the load shape.

- **Unavailability of DG resources:** this sensitivity analyzes how the system would behave assuming no DG resources, having a small increase on LOLE & LOLH, being more notable effect a decrease of capacity reserves during daytime hours.

- **Demand Response addition of CBES+ for full FY2026:** this sensitivity analyzes the impact of having the CBES+ demand response program available for the entire FY2026 (instead of being available only from July to October 2025 as it is assumed in the base case). This program is helpful by providing an extra 50 MW of capacity at peak hours when system capacity reserves are close to reach zero, providing energy at the moments is most needed.

- **Demand response addition of backup generators:** Like the CBES+ program sensitivity, this analysis assumes having for all FY2026 a demand response program that consists of some customers use their own backup generators during peak hours to disconnect from the grid by using their own generated electricity, and hence, reducing electric System Load. For simulations purposes, 50 MW of load reduction at peak hours was assumed. Note that as the base case includes the CBES+ program from July through October, the sensitivity of addition of backup generators includes these 50 MW of CBES+ for the first 4 months of the FY2026, plus the 50 MW of demand reduction at peak hours from the backup generators, summing to a total of 100 MW of demand response from July 2025 to October 2025, and 50 MW from November 2025 to June 2026.

- **Force Majeure Scenario:** this sensitivity captures how resource adequacy could be affected in case that Puerto Rico experiences a major event such as a hurricane, earthquake, or any other event that could cause a prolonged widespread outage. Behavior of the electric system during previous major events was analyzed in the development of this sensitivity. Assumptions in this sensitivity include selecting September 15, 2025, on which system availability and load falls to zero (i.e. a full blackout occurs). Then, system availability and load gradually start to ramp up, simulating the restoration process. System Load was assumed to recover in a full month, while generation fleet availability was assumed to fully recover to the same state as before the “event” 6 months after. During this 6-month period, the forced outage rate of all units was assumed to be 50% higher than base case assumptions. More detail about the analytics and results of this sensitivity can be found in appendix A.

These 20 sensitivity analyses are grouped into the following 4 themes:

- Unavailability of Resources
- Addition of Multiple Resources
- Load / Demand Affected Sensitivities
- Force Majeure Scenario

An overview of the findings of each one of these themes is presented below. Detailed descriptions and results of each sensitivity is presented in Appendix A.

3.2.0 Loss of Load Expectation (LOLE)

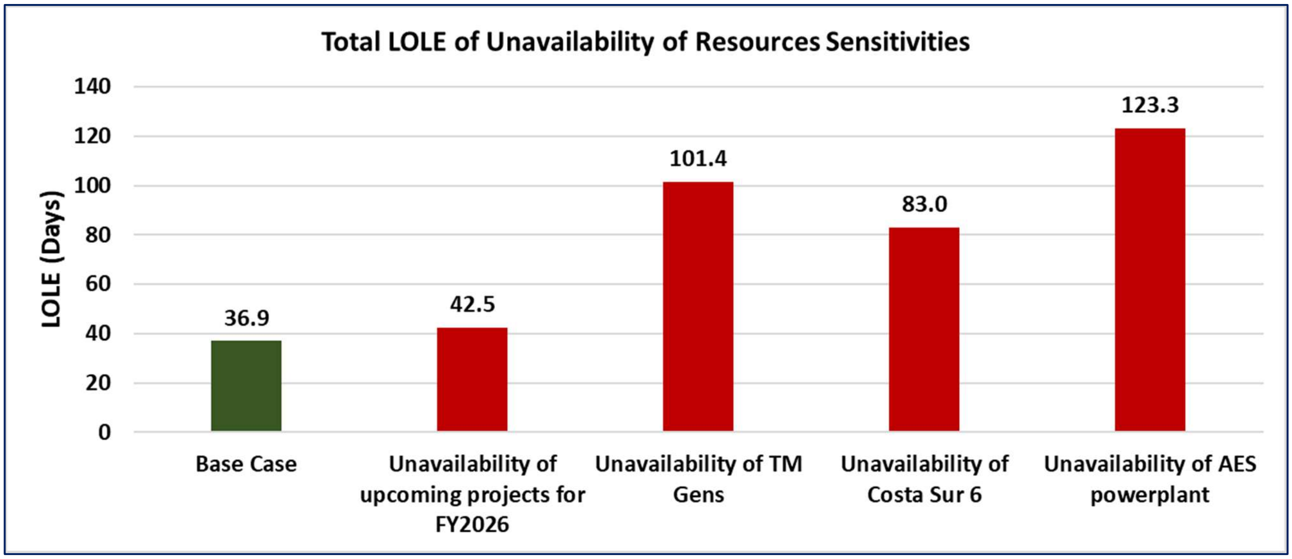
Unavailability of Resources:

Four sensitivity analyses were undertaken to analyze the negative impact on resource adequacy if some resources were not available for FY2026. Each one of the following sensitivities were defined at the beginning of this section:

- Unavailability of upcoming projects for FY2026
- Unavailability of TM generators
- Unavailability of Costa Sur 6
- Unavailability of AES

Figure 3-12 below demonstrates how much these sensitivity analyses related to the unavailability of resources can negatively affect resource adequacy. Besides the sensitivity of the unavailability of the upcoming projects for FY2026, the Loss of Load Expectation (LOLE) would likely increase over 80 days (vs. 36.9 in the Base Case). The sensitivity results of the unavailability of the upcoming projects for FY2026, which consists of 3 solar projects, 1 BESS project and the CBES+ project, demonstrates that the contribution of solar and BESS is not that big compared to the effect that a thermal power plant would have.

Figure 3-12: Impact on LOLE From Resources Unavailability Sensitivity Analyses



As expected for Puerto Rico's modest-sized islanded electricity system, the Base Case analysis demonstrates that outages to individual generators 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 better able to manage outages to individual generators, simply because there are many other available generators that can make up for any losses of generation.

Addition of Multiple Resources:

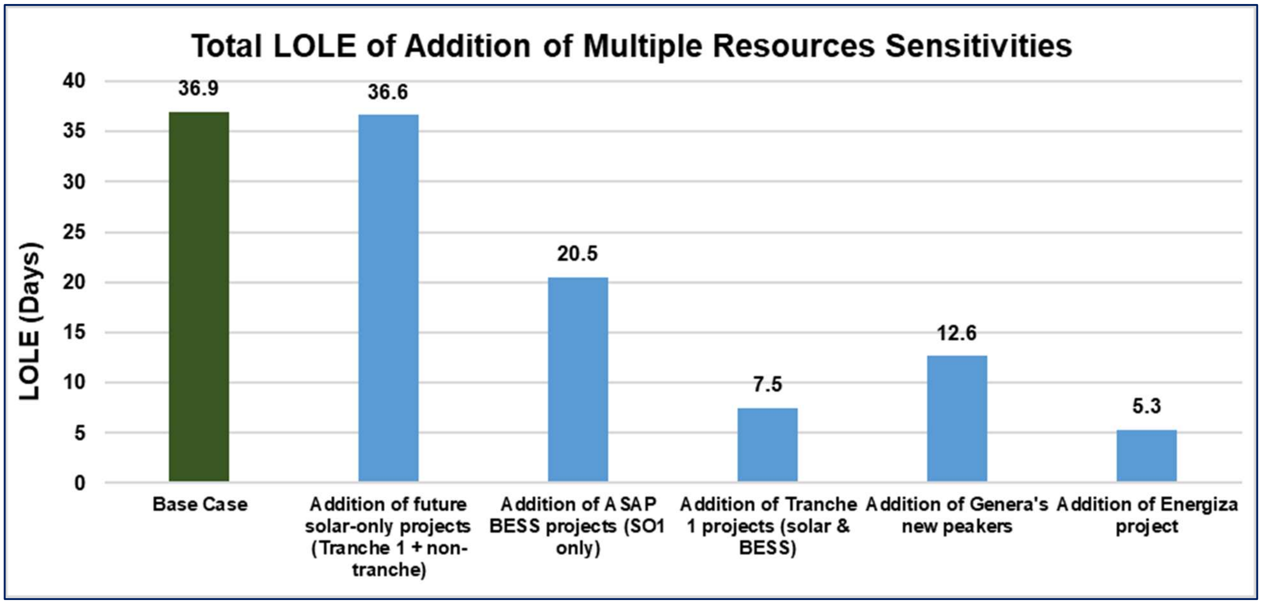
Nine sensitivity analyses were undertaken to analyze the hypothetical positive impact on resource adequacy if some resources would be available in FY2026. Each one of the following sensitivities were defined at the beginning of this section:

- Addition of future solar-only projects (Tranche 1 + non-tranche solar)
- Addition of ASAP BESS projects (SO1)
- Addition of ASAP BESS projects (SO1 + SO2)
- Addition of Genera BESS projects
- Addition of LUMA's 4x25 BESS projects
- Addition of Tranche 1 projects (Solar & BESS)
- Addition of Tranche 1 + ASAP (SO 1 & SO 2) + Genera BESS + LUMA 4x25 BESS
- Addition of Energiza project
- Addition of Genera peakers

Figure 3-13 shows the results of five of the above sensitivity analyses (results from all sensitivities can be found in Appendix A). First, the sensitivity analysis "Addition of future solar-only projects (Tranche 1 +

non-tranche)" confirms that adding more solar energy resources to the system does not have a big impact on reducing LOLE since most load shed events occur at peak demand hours (6:00 p.m. – 11:00 p.m.) when there is no solar production available. Adding batteries or a combination of solar with batteries can significantly reduce the LOLE events, as can be seen when comparing the base case (36.9 days/year), and the addition of ASAP SO1 BESS project (20.5 days/year) and/or the addition of Tranche 1 solar and BESS projects (7.5 days/year). The reduction in LOLE is notable since the batteries help the system cover for peak loads in peak demand hours. Finally, adding new thermal resources can also help improve the reliability of the system significantly, reducing the base case (36.9 days/year) LOLE events to 12.6 days/year if the Genera Peakers project is added and to 5.3 days/year if the Energiza project is added.

Figure 3-13: Impact on LOLE From Addition of Multiple Resources Sensitivity Analyses



Load/Demand Affected:

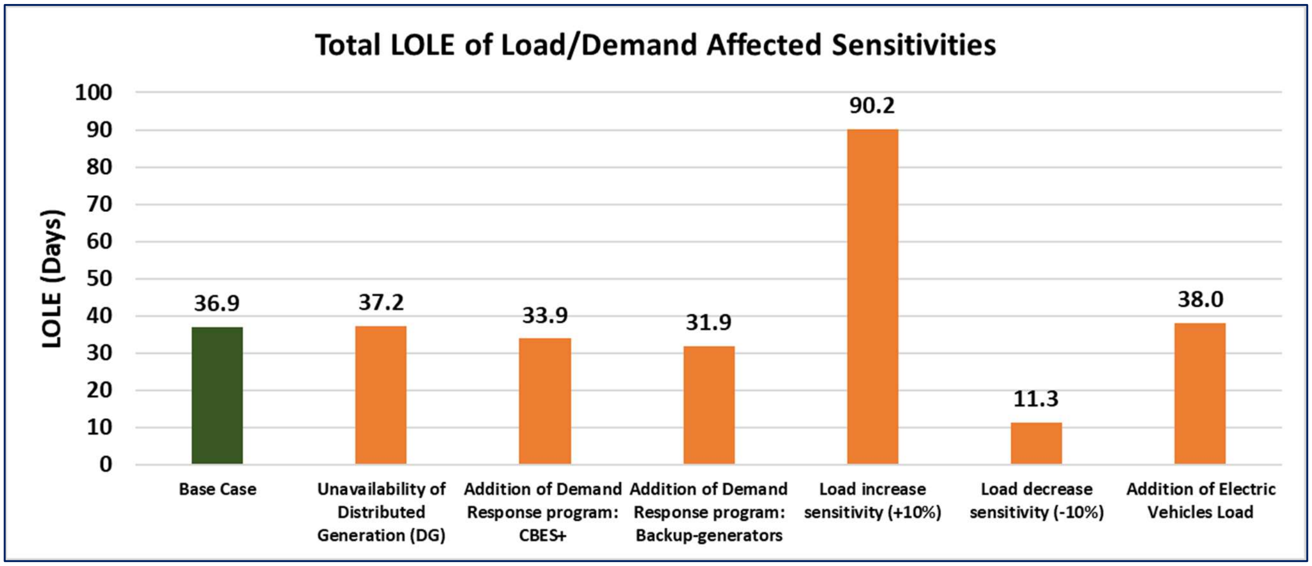
Six sensitivity analyses were undertaken to analyze the effect on resource adequacy if Puerto Rico electricity demand patterns and levels during FY2026 were different from those assumed in the base case. Each one of the following sensitivities were defined at the beginning of this section:

- Unavailability of Distributed Generation (DG)
- Addition of Demand Response program: CBES+
- Addition of Demand Response Program: Backup-generators
- Load Increase (+10%)
- Load Decrease (-10%)
- Addition of Electric Vehicle Load

Figure 3-14 below shows how LOLE is affected based on changes in demand. First, it can be noticed that the Unavailability of Distributed Generation (DG) only produces a slight increase in LOLE (from 36.9 to

37.2), because the contribution of the DG (rooftop solar) has a limited impact due to the fact that DG contributes primarily during daylight hours, while most LOLE events occur during evening peak demand (between 6:00 p.m. and 11:00 p.m.), after solar generation has ceased. In contrast, the two demand response programs analyzed, CBES+ (50 MW) and backup-generators (50 MW), have a positive contribution to the system, possibly reducing between 3 to 5 LOLE compared to the base case. Meanwhile, a 10% decrease in the expected hourly load for FY2026 could reduce the LOLE by 26 days/year, while a 10% increase could increase the LOLE by another 53 days/year. Finally, the hypothetical 60 GWh of consumption from EV's could have a minimal impact on resource adequacy in Puerto Rico in FY2026.

Figure 3-14: Impact on LOLE for Load/Demand Affected Sensitivity Analyses

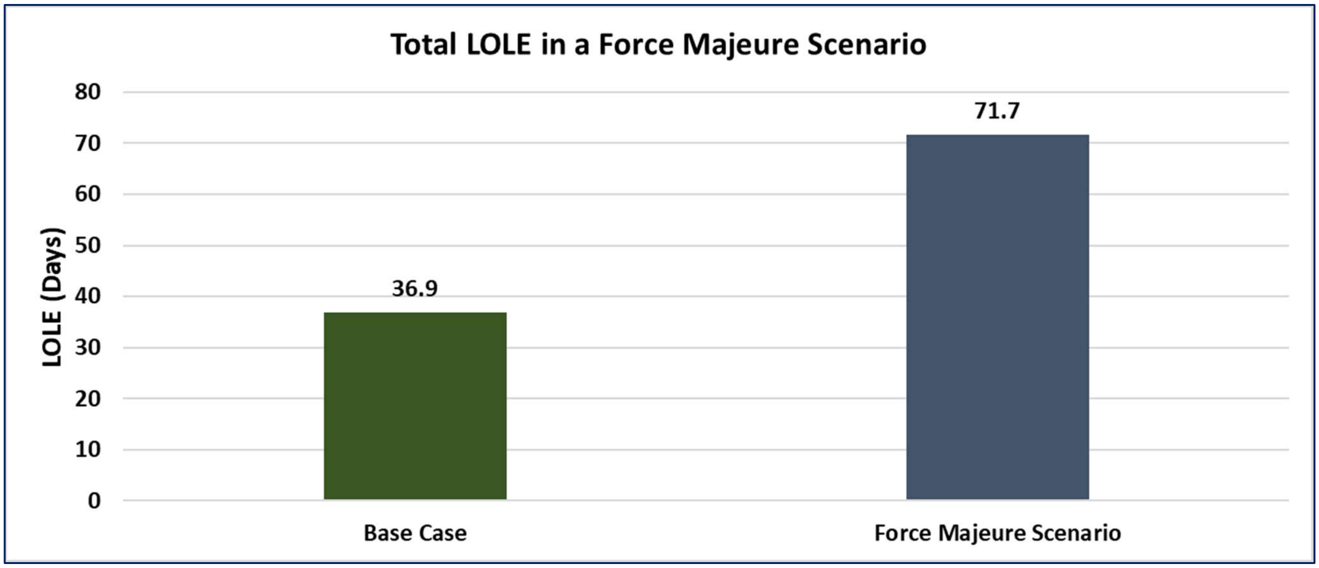


Force Majeure Scenario:

This sensitivity analysis was undertaken to analyze the negative impact on resource adequacy if a major event causes a widespread and prolonged outage on the island. The explanation of the assumptions and how the scenario was developed is presented at the beginning of this section.

Figure 3-15 compares the base case with a force majeure scenario, showing that could nearly double LOLE.

Figure 3-15: Impact on LOLE in a Force Majeure Scenario

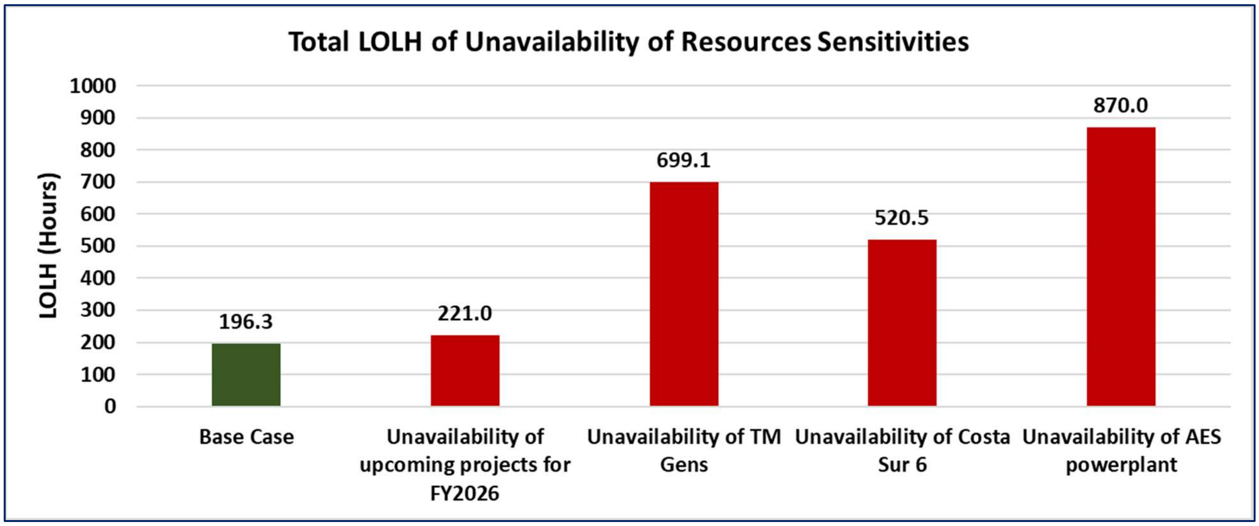


3.2.1 Loss of Load Hours

Unavailability of Resources:

LOLH results show that unavailability of thermal resources greatly affects resource adequacy: the unavailability of Costa Sur 6, TM generators and AES are forecasted to increase LOLH by more than 150%. Unavailability of upcoming resources for FY2026 shows a more modest increase from 196 to 221 hours, stemming from the unavailability of CBES+ demand response program from July 2025 through October 2025, and the multiple new solar and BESS upcoming projects during FY2026.

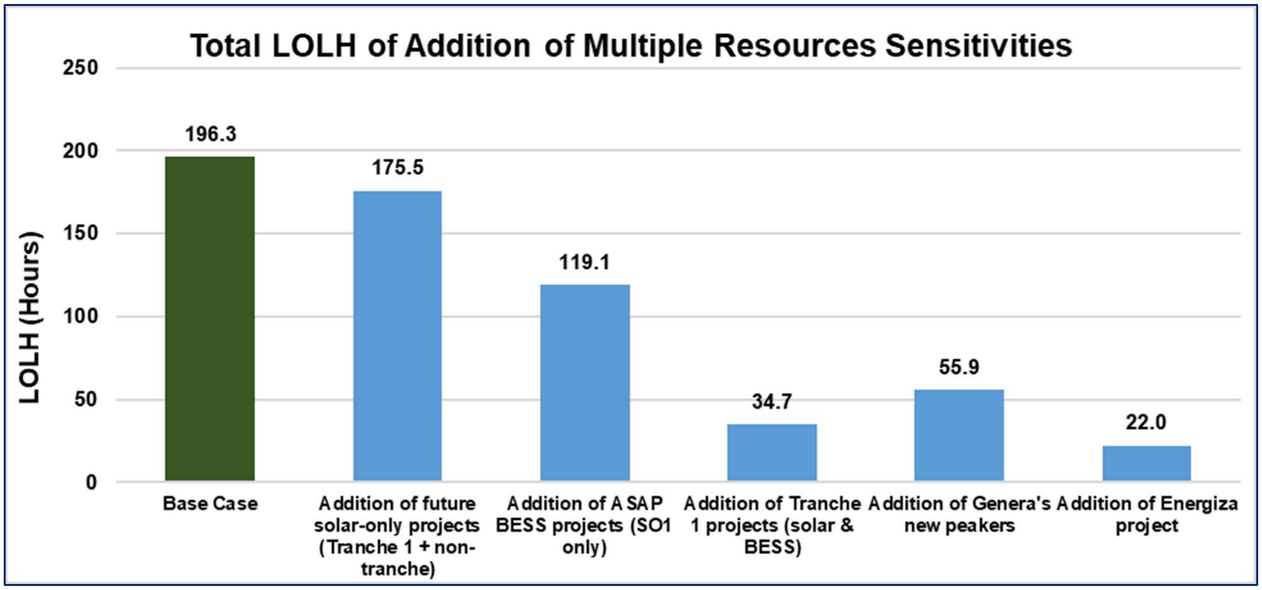
Figure 3-16: LOLH Results Comparison Between Base Case and Unavailability of Resources



Addition of Multiple Resources:

Figure 3-17 below shows how the addition of multiple resources reduces LOLH depending on the resource type. The sensitivity investigating the addition of solar-only projects reflects 945 MW of new capacity installed and yet barely reduces LOLH since these resources provide capacity during daytime only and not on peak hours during the evening. The addition of BESS projects reduces the LOLH number more because they are available during peak hours in the evening and are recharged during daytime hours when load-shed risk is lower. Thermal resources addition are the ones that have the better resource adequacy improvement since these resources could be able to produce energy at any hour of the day.

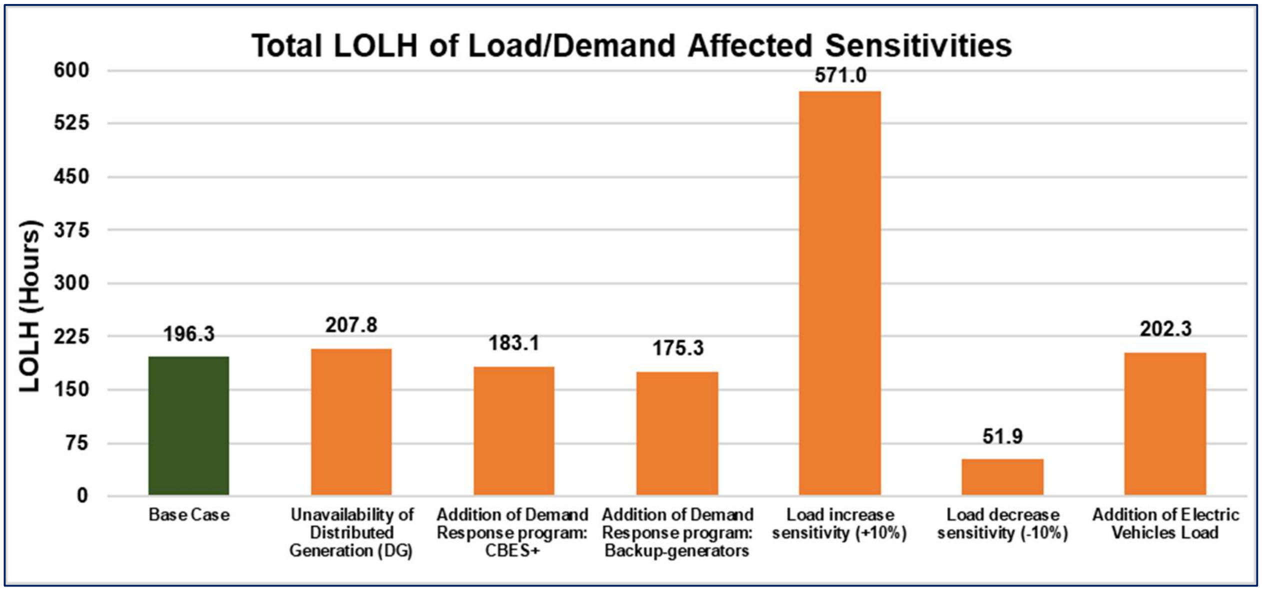
Figure 3-17: LOLH Results Comparison Between Base Case and Addition of Resources



Load / Demand Affected Sensitivities:

The following set of sensitivities involves changes in the Electric Demand, where the unavailability of DG resources would increase forecasted LOLH only from 196 to 208 hours, as most of these resources are customers with solar PV equipment that produce electricity only during daytime hours when loss of load probability is low. The addition of demand response programs could help reduce LOLH by providing extra capacity (CBES+) or reducing electric System Load (backup generators) at peak hours. The addition of EVs load has a small increase on LOLH due to the small load increment these resources have.

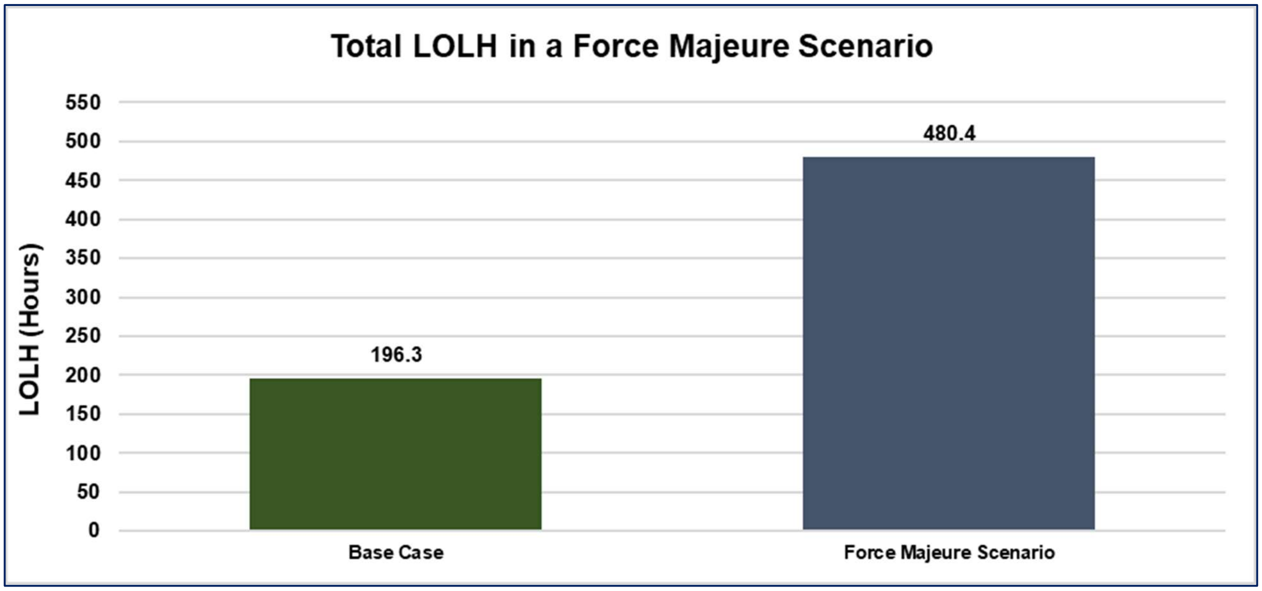
Figure 3-18: LOLH Results Comparison Between Base Case and Load Affected Sensitivities



Force Majeure Scenario:

Figure 3-19 below shows the comparison in LOLH between base case and a force majeure scenario, where it shows that, in a force majeure scenario, approximately a 145% increase of LOLH could happen. Historically, when a major event impacts the electric system, forced outages are more likely to happen since, depending on the type of event, critical component parts of a unit can be affected, creating further limitations on the units and more risk of resource inadequacy. Consequently, LOLH could increase in such scenario.

Figure 3-19: LOLH Results Comparison Between Base Case and Force Majeure Scenario

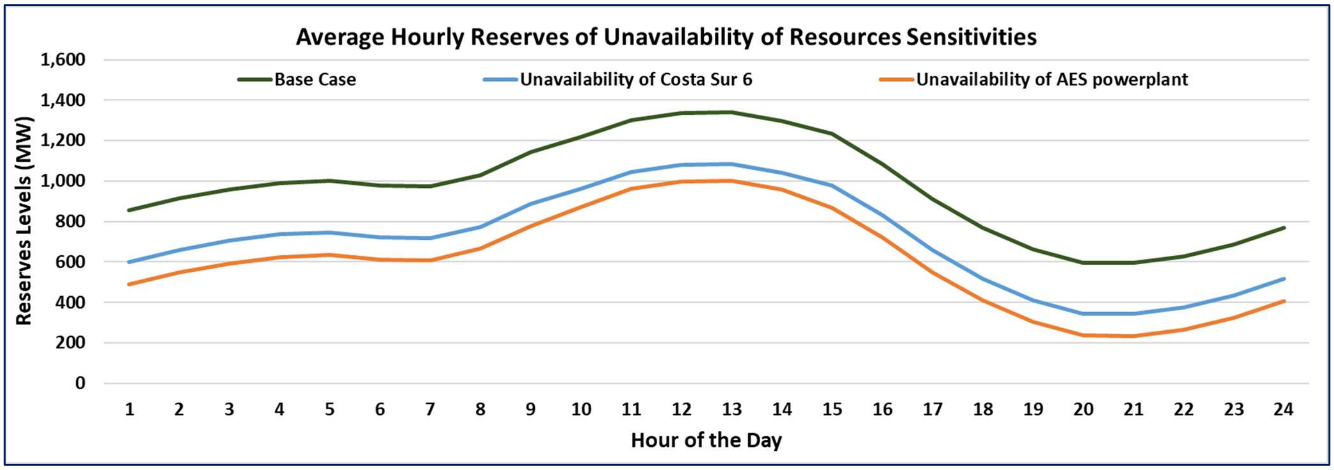


3.2.2 Capacity Reserves Margin

Unavailability of Resources:

Figure 3-20 compares the hourly average reserve levels of the base case with the reserve levels forecasted in the sensitivities assuming the unavailability of Costa Sur 6 and AES power plants. The results show that not having Costa Sur 6 in FY2026 could represent a reduction of approximately 200 MW in reserve levels while not having AES could represent a reduction of approximately 300 MW. These results reaffirm that the unavailability of these resources could have a negative impact on resource adequacy at each hour of every day. Also, these results are consistent with the LOLE results presented in section 3.2.0. Figure 3-20 does not show the sensitivity of the unavailability of the upcoming projects for FY2026 and the unavailability of the TM generators since the results are similar to the base case and to the unavailability of Costa Sur 6 respectively. It can be noticed in the graph that the average lowest reserve level occurs at peak demand hour (6:00 p.m. to 11:00 p.m.) in all cases.

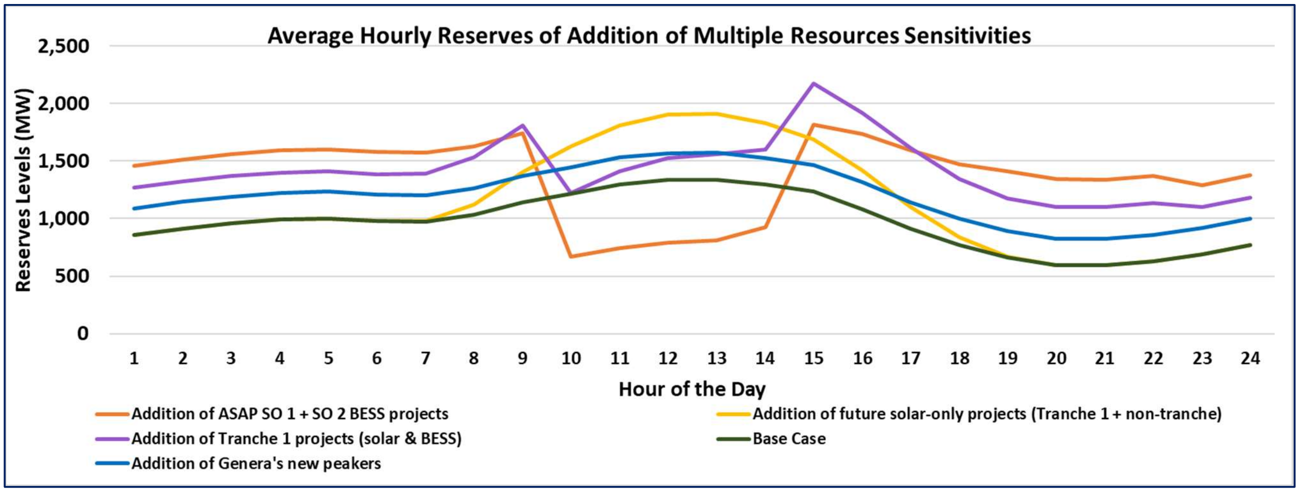
Figure 3-20: Impact on Average Hourly Reserves of Unavailability of Resources Sensitivity Analyses



Addition of Multiple Resources:

In general, increasing the amount of available generation resources enhances system reliability by boosting reserve margins, reducing the likelihood of generation shortfalls. Some of the resources analyzed and plotted in Figure 3-21 are solar-only projects (Tranche 1 and non-tranche), BESS-only projects (ASAP SO1 & SO2), a hybrid of solar and BESS (Tranche 1 projects), and thermal units (Genera peakers). Compared with the base case (green line), adding more solar-only resources to the system (yellow line) increases reserve levels but only during daytime hours. For BESS and hybrid projects, the increment in reserve levels is not linear since these resources are assumed to be charged between 10:00 a.m. to 2:00 p.m. under normal operating conditions. This creates a reduction in reserve levels during that time and can be noticed on Tranche 1 (solar & BESS) sensitivity, where the reserve levels drop between 600-900 MW. On the other hand, adding thermal resources (such as the Genera peakers) increases reserves by approximately an increment of 200 MW at every hour compared to the base case. This is because thermal resources could be available at every hour and not just during certain hours during the day, as is the case for solar and BESS.

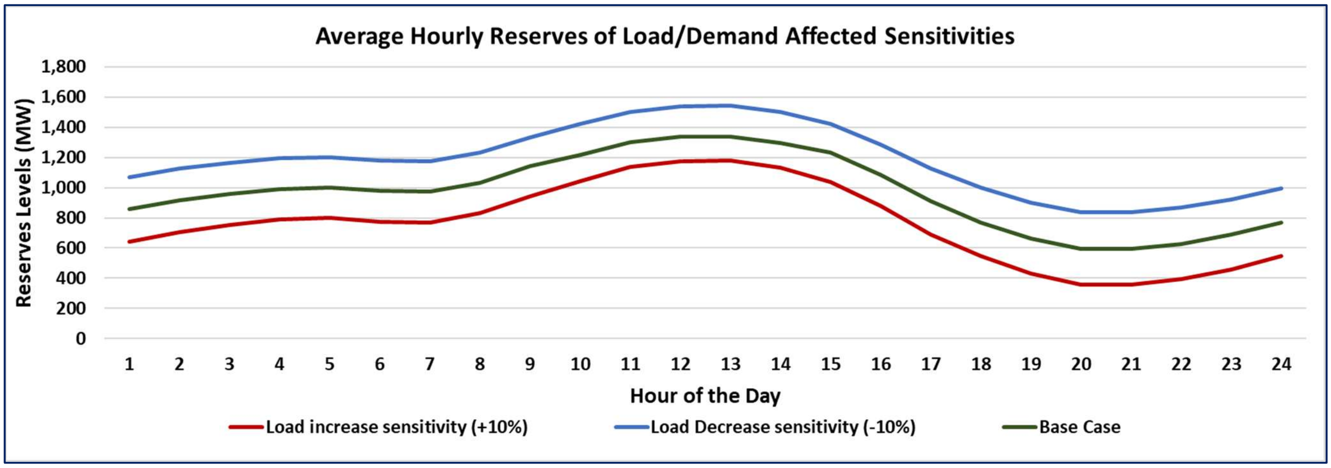
Figure 3-21: Impact on Average Hourly Reserves on Addition of Multiple Resources Sensitivity Analyses



Load/Demand Affected Sensitivities:

Figure 3-22 illustrates the variations in reserve levels when the load is affected in different scenarios. For example, if the load is increased by 10% for each hour of the day, it would produce a reduction in reserve levels (approximately 200 MW less at every hour). On the other hand, decreasing the load by 10% will produce a 200 MW increase in reserve levels at every hour. Other load-affected sensitivities were not included in the figure below since their effect on reserves relative to the base case was small.

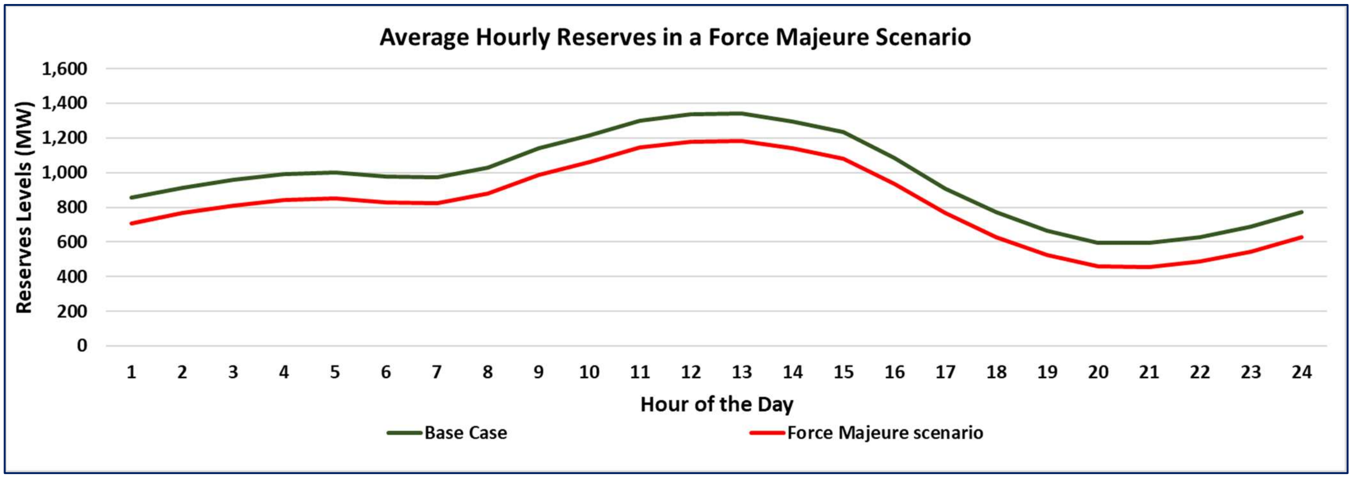
Figure 3-22: Impact on Average Hourly Reserves of Load/Demand Affected Sensitivity Analyses



Force Majeure Scenario:

In a Force Majeure Scenario, the impact on hourly reserve levels will be most noticeable on the month of the force majeure event occurrence. Figure 3-23 compares the average hourly reserve levels between the base case and in a force majeure scenario. Even though this kind of event has biggest effect on reserves immediately after occurrence, a lingering effect will last much of the remainder of the year, reducing average reserve levels by approximately 150 MW at each hour.

Figure 3-23: Impact on Average Hourly Reserve in a Force Majeure Scenario

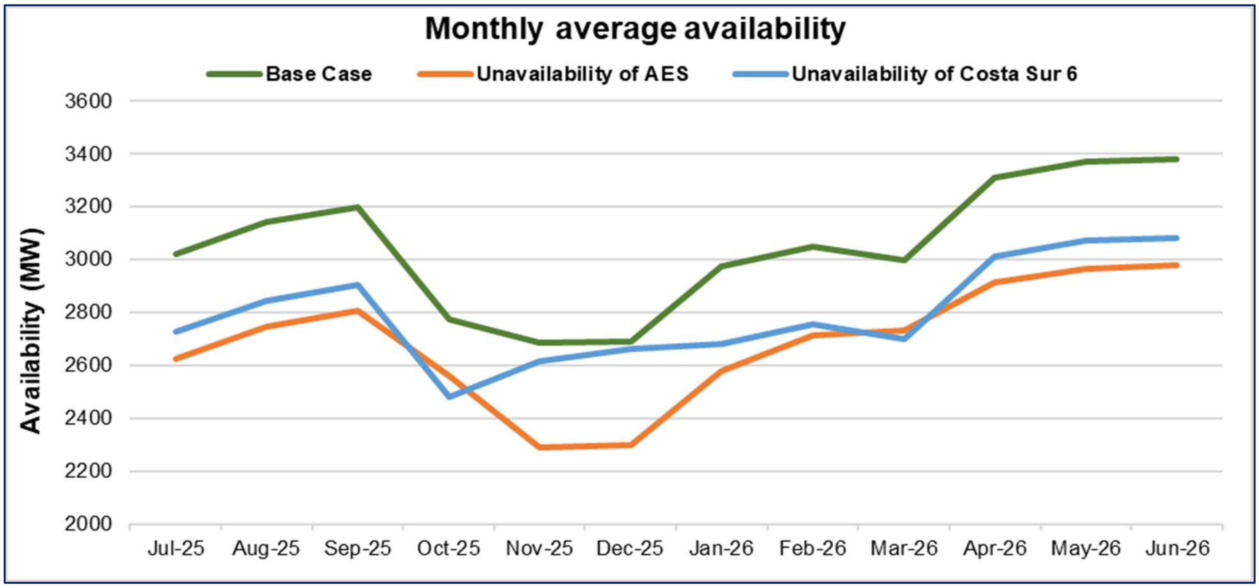


3.2.3 Available Capacity

Unavailability of Resources:

Figure 3-24 shows how availability worsens with the two most severe unavailability scenarios: the loss of Costa Sur 6 and the loss of AES. In both sensitivities, average availability during July-September is consistently below 2800 MW, whereas daily peak demand during these months is frequently above 2800 MW, thus illustrating the high risk of frequent load-shedding under these sensitivities.

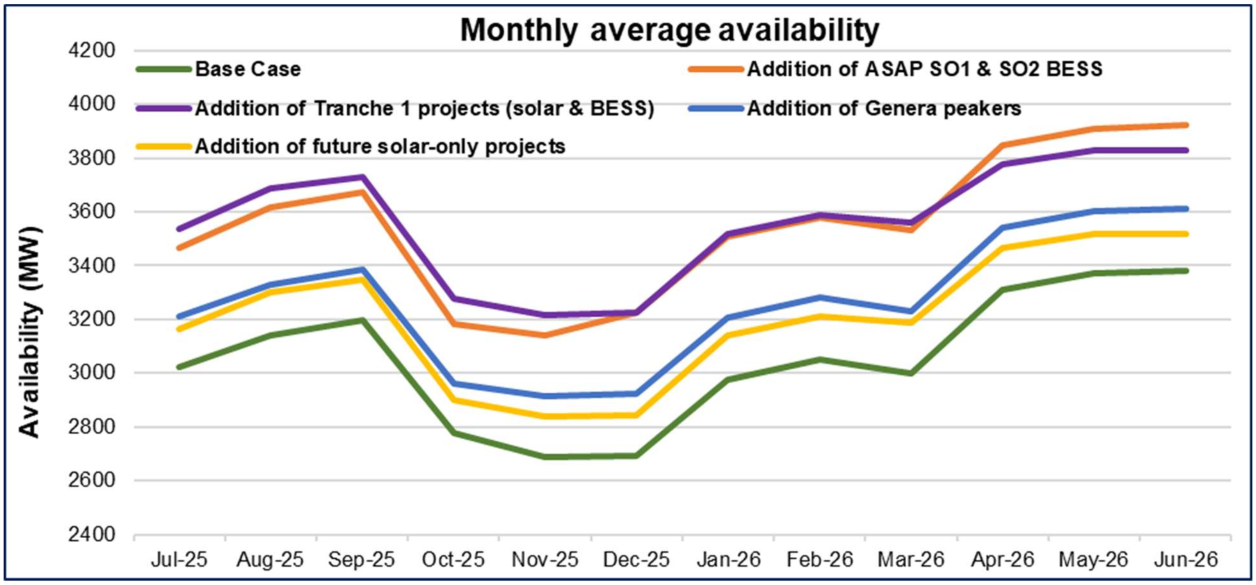
Figure 3-24: Monthly Availability Comparison Between Base Case and Unavailability of Resources Sensitivities



Addition of Multiple Resources:

By rule-of-thumb, addition of new resources will increase average availability on the system, but availability is not entirely defined by the Capacity of the resource: one of the principal factors is at what hours of day these resources will provide energy and how these resources will operate. In Figure 3-25 below, even though the solar-only resources add approximately 945 MW, the monthly average availability is less than Genera peakers sensitivity (244 MW), because they are available only during daytime, while Genera peakers can be available at any hour of day. On the other hand, if multiple standalone BESS projects are added or if solar additions are combined with BESS, availability increases further. Finally, when comparing all sensitivities, a notable increase in availability can be seen from April through June 2026. This is due to the expected addition in March 2026 of the first utility-scale BESS project to the Puerto Rico electric system.

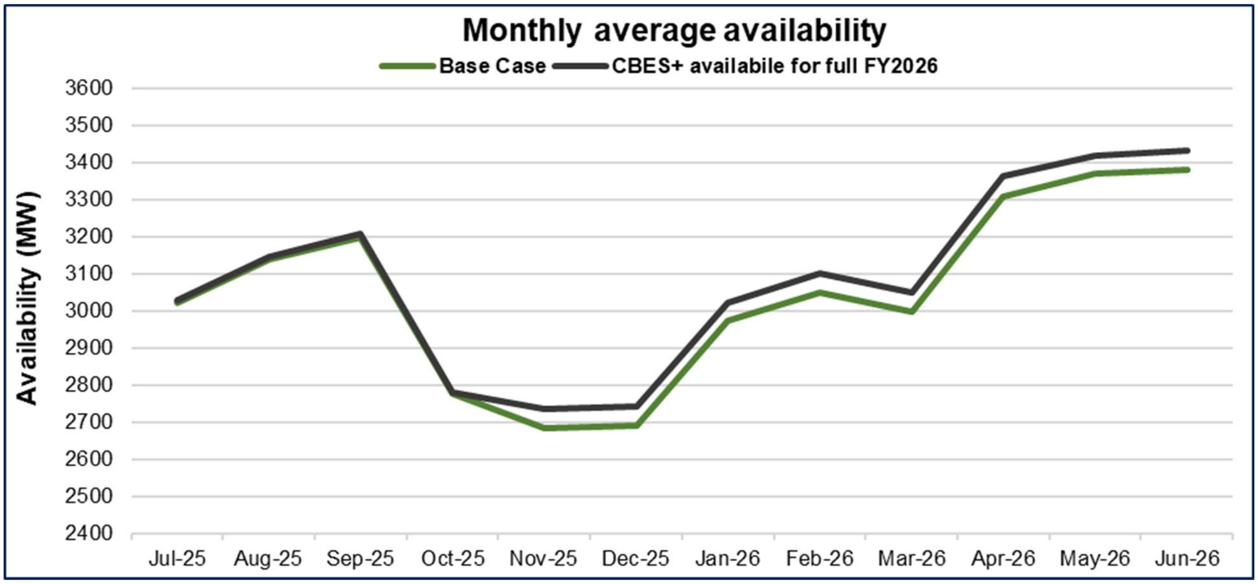
Figure 3-25: Monthly Availability Comparison Between Base Case and Addition of New Resources



Load / Demand Affected Sensitivities:

Under the load sensitivities, availability mostly remains unchanged, since none of the assumptions about generation supply were altered from Base Case levels. The only exception is the CBES+ sensitivity. This sensitivity, regardless that is classified as a load sensitivity, has an impact on availability since CBES+ are effectively additional supply-side resources for the grid that are coming from the demand side (demand response) via injections of energy from BTM BESS installations to the grid during peak hours. This demand response resource can avoid load shed events driven by small deficiencies in capacity availability and/or help mitigate the duration of load-sheds.

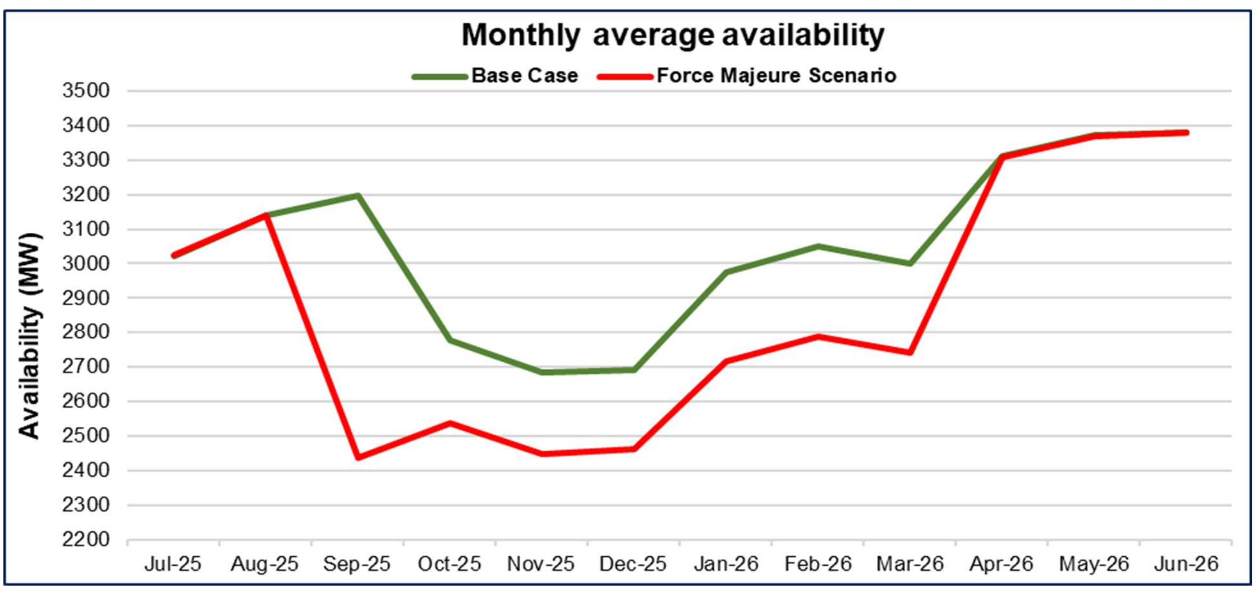
Figure 3-26: Monthly Availability Comparison Between Base Case And CBES+ Demand Response Program Available for Full FY2026



Force Majeure Scenario:

In a Force Majeure Scenario, both availability and load decrease drastically in the aftermath of the force majeure event occurrence, and the restoration process could be challenging, as was experienced during previous major events that impacted Puerto Rico. In previous years, availability struggled to fully recover to levels before the major event occurred, leaving the electric system vulnerable and with increased risk of resource inadequacy until repairs were largely completed. Figure 3-26 below makes the comparison of availability with the base case and a force majeure scenario, where availability is notably affected during the assumed recovery period by an approximate of 250 MW between October and March.

Figure 3-27: Monthly Availability Comparison Between Base Case and Force Majeure Scenario



Appendix A: Findings from Sensitivity Analyses

This appendix provides detailed results from the sensitivity analyses conducted as part of this resource adequacy assessment. Each sensitivity scenario incorporates specific assumption changes, which are described and explained in the sections that follow. The results presented here are supplementary to the ones discussed in Section 3.

A.1 Unavailability of Resources

This section contains the analytic results of the resource adequacy assessment for a set of sensitivity analyses. These scenarios explore the impact of varying assumptions, including the unavailability of certain fossil generation resources in Puerto Rico and the exclusion of all new resources scheduled to come online during FY2026:

- Unavailability of upcoming projects for FY2026
- Unavailability of TM generators
- Unavailability of Costa Sur 6
- Unavailability of AES powerplant

When compared to the Base Case, each of these four sensitivities scenarios involving resource unavailability results in deterioration of resource adequacy. As shown in Table A-1 below, assuming the unavailability of all upcoming projects for FY2026 leads to a LOLE increase of 15%, while the unavailability of the TM generators results in a 175% increase on the forecasted LOLE, while the unavailability of Costa Sur Unit 6 increases LOLE by 125%. The most significant impact is observed with the unavailability of the AES power plant, which causes a 234% increase in LOLE.

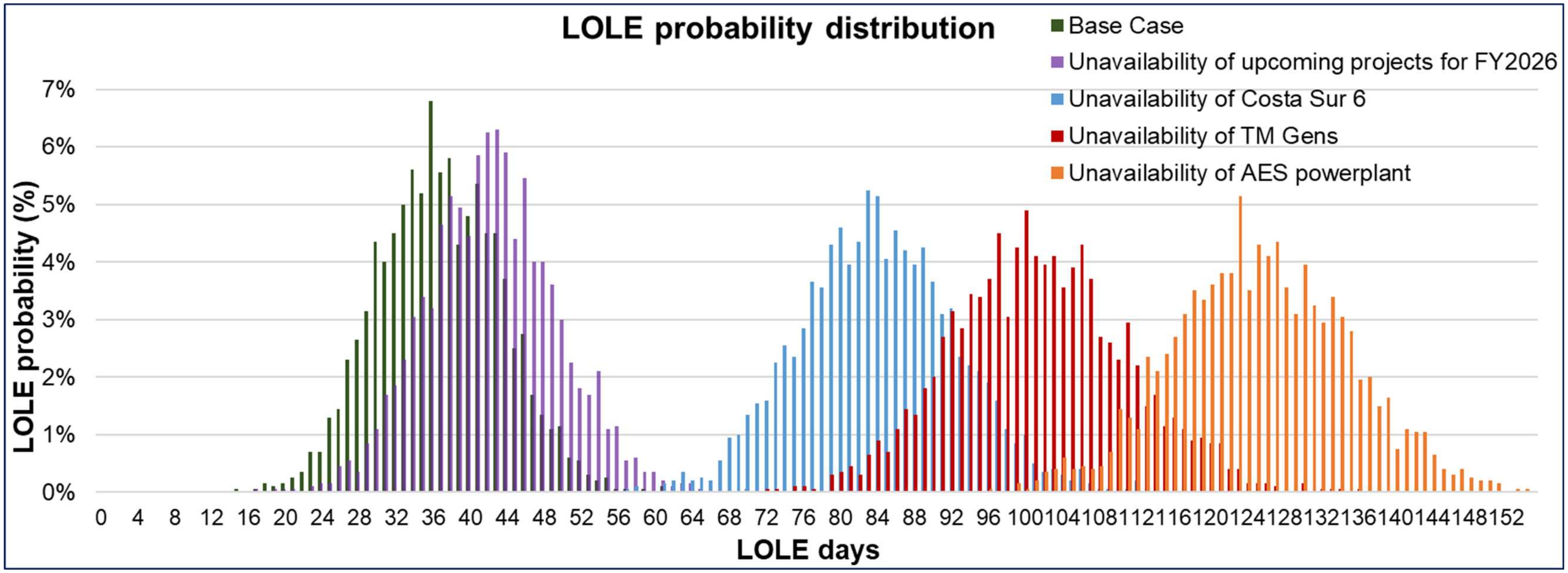
Table A-1: Calculated Resource Adequacy Measures Associated with Unavailability of Resources

Sensitivity Analysis	Loss of Load Expectation (LOLE)	Loss of Load Hours (LOLH)
Base Case	36.9 Days / Year	196.3 Hours / Year
Unavailability of upcoming projects for FY2026	42.5 Days / Year	221.0 Hours / Year
Unavailability of TM generators	101.4 Days / Year	699.1 Hours / Year
Unavailability of Costa Sur 6	83.0 Days / Year	520.5 Hours / Year
Unavailability of AES powerplant	123.3 Days / Year	870.0 Hours / Year

NEPR-MI-2022-0002

Figure A-1 shows how the probability distribution of outcomes for LOLE significantly worsens relative to the Base Case if some of the existing resources become unavailable, while the unavailability of near-future projects increases is smaller due to the limited amount of capacity that is expected to interconnect during FY2026.

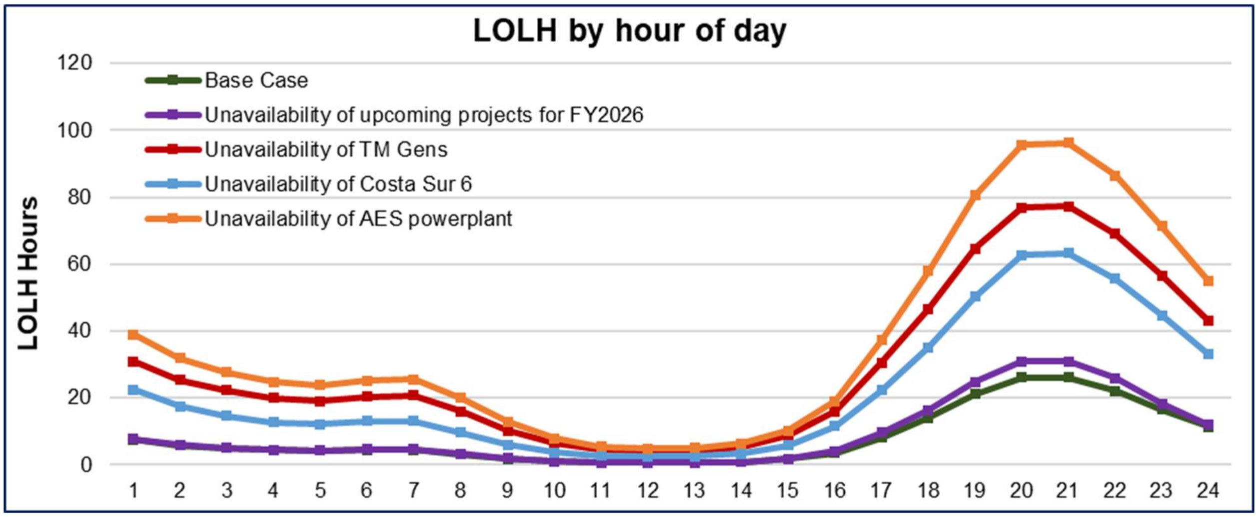
Figure A-1: Comparison of LOLE Probability Distributions Associated with Unavailability of Resources



NEPR-MI-2022-0002

Meanwhile, Figure A-2 indicates how much LOLH distributed by hour of day increases relative to the Base Case for each of these four sensitivity analyses. Unavailability of thermal resources impact is noted on every hour of the day since, as mentioned before through the report, these resources can be available at any hour of day, while, when comparing the base case with the unavailability of upcoming projects, hours of day affected are mostly the peak hours only, principally due to the unavailability of the CBES+ program and the BESS project that is expected to enter online by the last quarter of FY2026.

Figure A-2: Comparison of LOLH Associated with Unavailability of Resources



NEPR-MI-2022-0002

Individual Sensitivity Analysis: Unavailability Of Resources

The following sub-section will compare each sensitivity with the base case, specifically comparing average monthly reserves by hour of day, and monthly availability.

Capacity reserves are illustrated using heat maps, which apply a gradient color scheme to represent reserve levels. Green indicates reserves above 650 MW. As reserve levels decrease toward 650 MW, the color shifts from green to yellow, and then to red as reserves drop further. The closer the reserves are to zero, the deeper the red becomes. Black cells indicate negative reserves, meaning a generation shortfall where electricity demand exceeds available supply. These black zones correspond to LOLE (Loss of Load Expectation) and LOLH (Loss of Load Hours) events. Figure A-3 illustrates the dynamics of the reserves through this heat map representation.

Figure A-3: Reserves Heat Map Gradient Coloring Methodology

Unavailability of Upcoming Projects for FY2026:

This sensitivity scenario includes upcoming resources such as solar projects, BESS (Battery Energy Storage Systems), and the CBES+ demand response program. Capacity reserves are slightly lower during peak hours from July to October due to the absence of CBES+. A more noticeable increase in midday reserves begins in December 2025, coinciding with the projected operational start of the Ciro One solar project. The addition of two more solar projects, anticipated to come online in May and June 2026, further enhances midday reserves. Finally, during the last three months of FY2026, peak-hour reserves are also impacted by the projected operational start of the first BESS project.

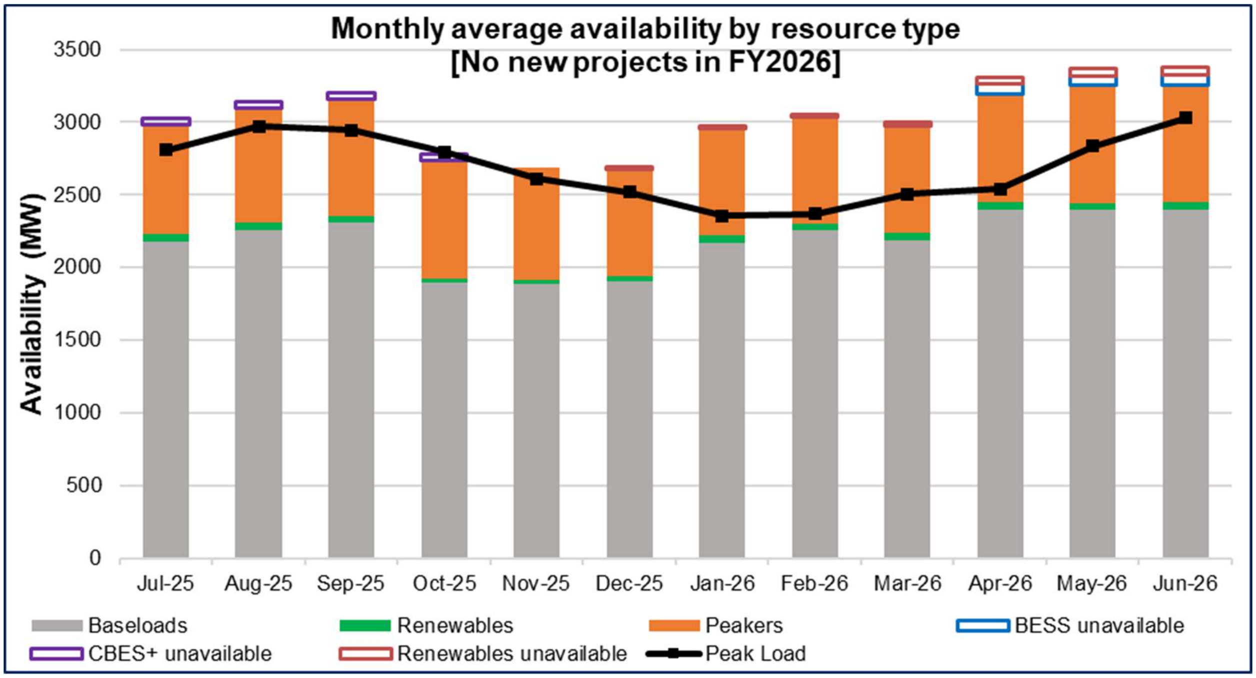
Figure A-4: Unavailability of Upcoming Projects for FY2026 Reserves Heat Map

Hour of Day	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Average by Hour
1	690	718	728	471	508	750	1,091	984	1,043	1,197	1,049	814	**837**
2	744	782	767	528	514	819	1,165	1,016	1,103	1,276	1,142	895	**896**
3	767	850	795	560	517	873	1,225	1,047	1,152	1,338	1,217	946	**941**
4	783	890	815	589	528	909	1,267	1,074	1,184	1,381	1,257	988	**972**
5	791	913	822	600	530	917	1,269	1,078	1,195	1,391	1,284	1,012	**983**
6	785	896	814	583	520	882	1,220	1,047	1,163	1,336	1,266	1,004	**960**
7	794	914	829	575	526	835	1,154	1,035	1,139	1,324	1,277	1,024	**952**
8	816	956	892	639	593	866	1,183	1,078	1,192	1,398	1,325	1,069	**1,001**
9	861	1,021	980	727	685	971	1,270	1,182	1,322	1,511	1,425	1,161	**1,093**
10	918	1,097	1,068	804	773	1,101	1,399	1,306	1,447	1,618	1,519	1,252	**1,192**
11	967	1,165	1,115	843	844	1,195	1,490	1,380	1,533	1,698	1,600	1,333	**1,263**
12	990	1,194	1,135	843	859	1,230	1,542	1,435	1,566	1,724	1,636	1,366	**1,293**
13	997	1,203	1,130	837	844	1,235	1,572	1,472	1,592	1,721	1,624	1,338	**1,297**
14	972	1,160	1,082	777	807	1,199	1,547	1,454	1,569	1,670	1,521	1,268	**1,252**
15	922	1,068	974	664	738	1,090	1,478	1,391	1,487	1,568	1,373	1,165	**1,160**
16	849	934	826	514	650	917	1,321	1,298	1,341	1,386	1,209	1,024	**1,022**
17	766	760	700	366	501	709	1,120	1,179	1,141	1,200	1,028	881	**863**
18	691	621	597	270	402	582	966	1,036	961	1,074	899	748	**737**
19	620	521	507	196	327	461	837	921	859	965	804	623	**637**
20	537	426	455	174	319	446	776	851	772	856	701	526	**570**
21	509	400	458	185	335	465	793	865	770	869	691	493	**569**
22	532	441	493	232	359	502	834	884	800	908	726	527	**603**
23	576	510	564	312	412	575	905	915	871	973	803	606	**668**
24	627	610	648	400	461	664	998	949	952	1,086	925	698	**751**
Average by Month	**771**	**835**	**800**	**529**	**565**	**841**	**1,184**	**1,120**	**1,173**	**1,311**	**1,179**	**948**	

NEPR-MI-2022-0002

In terms of availability, the absence of the CBES+ program slightly impacts the period from July to October 2025. Beginning in December 2025, renewable resource availability starts to decline. However, during the winter season, this reduction is minimal and barely noticeable. In the final three months of the study period, BESS availability is affected, leading to a slight but more noticeable reduction in total system availability. Figure A-5 below illustrates total monthly availability by resource type, alongside the forecasted monthly peak load for comparison.

Figure A-5: Monthly Average Availability of Unavailability of Upcoming Projects for FY2026 Sensitivity



NEPR-MI-2022-0002

Unavailability of TM Generators:

The TM generators are the most recent thermal additions to the electric system, contributing a total of 340 MW of capacity. Since their commissioning, these units have played a critical role in preventing more frequent and prolonged load shed events that might have occurred in their absence. As shown in Figure 3-8, the base case already includes multiple time intervals with inadequate reserve levels. Assuming the TM units are unavailable, the system would face an even greater risk of resource inadequacy. This is illustrated in the following figure, where every month shows a notable impact, particularly October 2025, which exhibits average negative reserves during peak hours. This indicates a high probability of frequent loss of load events during October peak hours if the TM units are not available for the entire month.

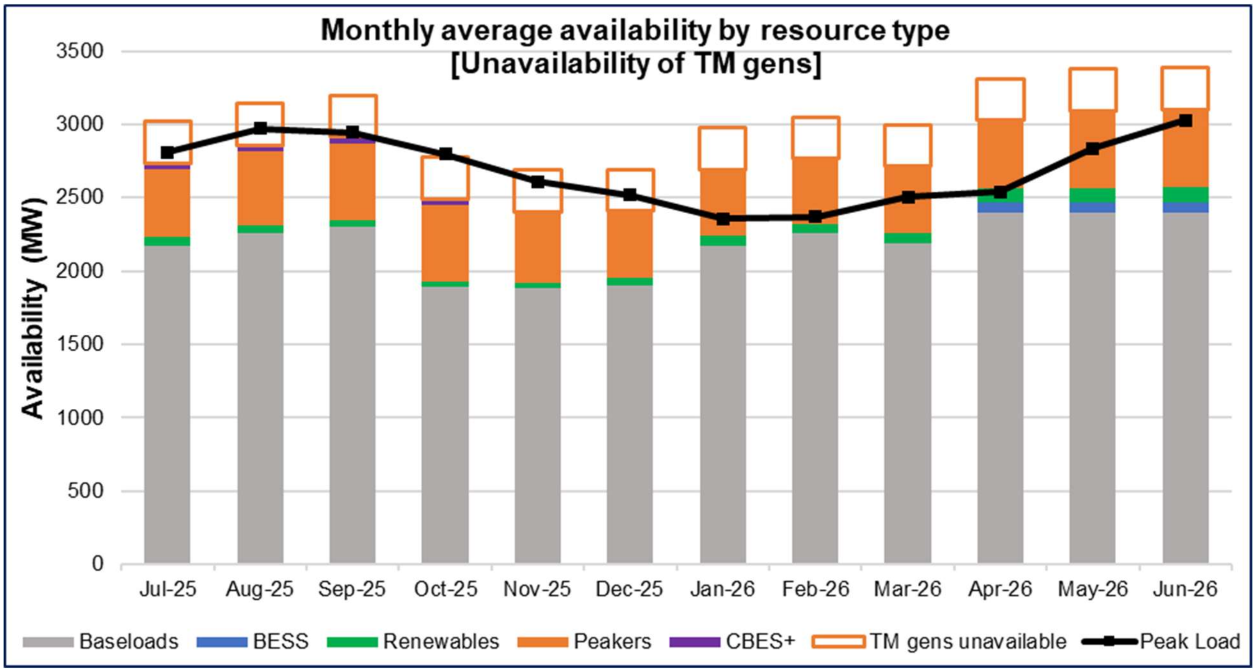
Figure A-6: Unavailability of TM Generators Reserves Heat Map

Hour of Day	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Average by Hour
1	411	432	443	186	222	470	805	704	757	994	838	592	**571**
2	462	497	483	243	229	539	879	736	818	1,072	929	672	**630**
3	485	565	511	276	231	593	939	768	867	1,133	1,005	724	**675**
4	500	605	532	304	241	628	980	794	899	1,177	1,046	767	**706**
5	509	628	540	315	244	637	984	797	909	1,186	1,073	790	**718**
6	502	611	531	299	233	600	935	766	875	1,132	1,053	783	**693**
7	511	628	546	290	238	553	867	753	851	1,121	1,072	812	**687**
8	532	671	610	352	305	589	899	800	913	1,223	1,150	893	**745**
9	577	736	697	440	398	711	1,005	919	1,065	1,379	1,302	1,041	**856**
10	634	810	784	517	487	856	1,151	1,060	1,204	1,366	1,288	1,037	**933**
11	682	878	831	556	557	962	1,256	1,146	1,302	1,472	1,398	1,154	**1,016**
12	707	906	850	557	572	1,004	1,316	1,210	1,341	1,509	1,452	1,207	**1,053**
13	714	915	845	551	559	1,009	1,348	1,252	1,370	1,507	1,436	1,169	**1,056**
14	689	872	796	491	522	972	1,320	1,231	1,345	1,469	1,337	1,098	**1,012**
15	640	781	688	378	454	853	1,244	1,160	1,255	1,503	1,306	1,102	**947**
16	568	646	540	231	366	668	1,075	1,056	1,103	1,290	1,117	946	**800**
17	487	474	416	89	217	443	857	924	884	1,068	902	769	**627**
18	412	337	315	**-1**	119	304	685	764	686	913	740	599	**489**
19	344	241	229	**-66**	44	181	550	640	573	785	625	447	**383**
20	264	152	180	**-87**	36	167	489	570	486	675	517	343	**316**
21	236	128	179	**-82**	51	186	506	584	485	688	507	307	**315**
22	257	164	212	**-45**	74	222	547	603	517	726	540	337	**346**
23	298	227	280	29	127	295	619	635	588	771	594	391	**405**
24	347	324	363	116	177	385	712	670	668	884	714	476	**486**
Average by Month	**490**	**551**	**517**	**248**	**279**	**576**	**915**	**856**	**907**	**1,127**	**998**	**769**	

The availability contribution of the TM generators is particularly evident given their recent addition to the system, which also influences the availability of peaking units, as shown in Figure A-7 below. Without the TM generators, the total system's monthly average availability would fall below the forecasted peak load during the first six months of the study period. This represents a significant risk to the electric system's ability to supply adequate resources.

NEPR-MI-2022-0002

Figure A-7: Monthly Average Availability of Unavailability of TM Gens Sensitivity



Unavailability of Costa Sur 6:

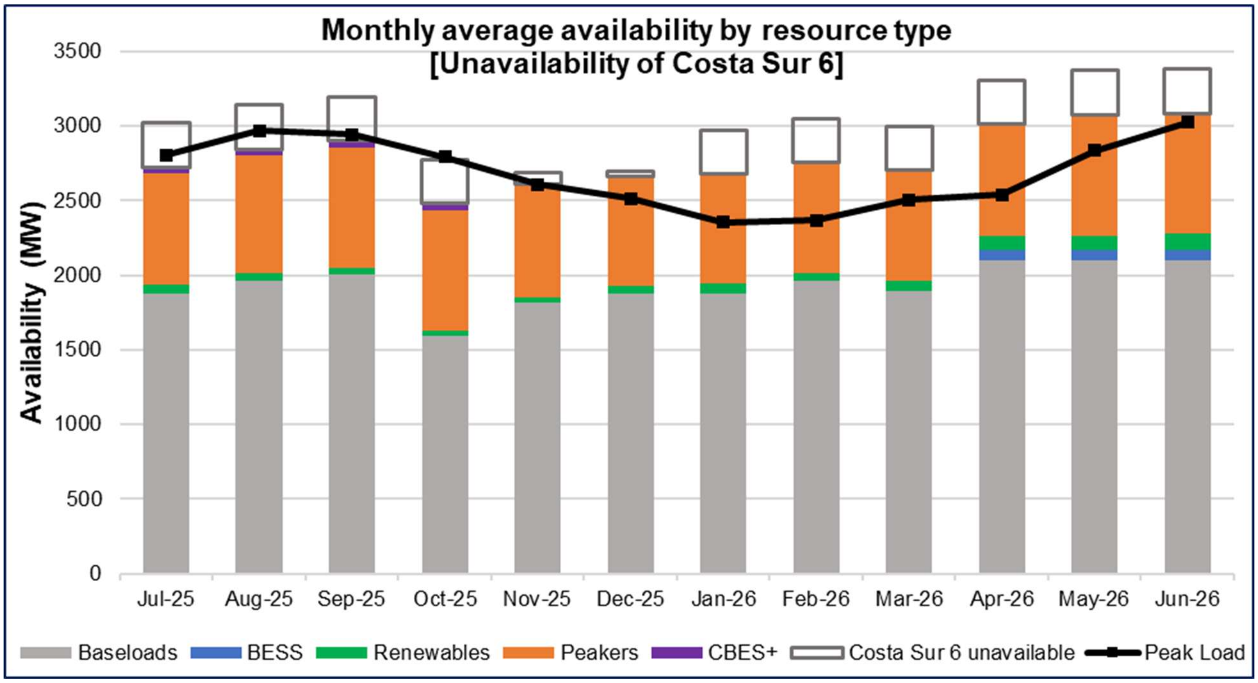
Losing a baseload unit has a significant impact on the system, as these resources provide the largest capacity within the electric grid. In this analysis, it was assumed that Costa Sur 6 would be offline for the entire study period. This scenario results in a substantial reduction in reserves across all hours of the day. Compared to the base case, the least affected months are November and December, since Costa Sur 6 is already scheduled for a planned outage during that time, which is accounted for in the base case assumptions.

Figure A-8: Unavailability of Costa Sur 6 Reserves Heat Map

Hour of Day	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Average by Hour
1	396	421	433	178	435	722	795	686	745	980	830	586	**601**
2	447	485	472	235	442	792	870	719	805	1,058	922	666	**659**
3	472	552	500	268	445	845	930	751	853	1,119	998	718	**704**
4	487	593	520	297	456	881	972	777	885	1,162	1,038	761	**736**
5	494	616	527	307	458	889	974	781	896	1,172	1,065	784	**747**
6	488	599	519	291	448	853	926	749	863	1,117	1,046	776	**723**
7	497	616	534	282	454	806	859	737	839	1,107	1,064	806	**717**
8	519	659	597	344	521	842	891	785	901	1,209	1,142	888	**775**
9	563	724	685	432	614	965	995	905	1,053	1,365	1,294	1,037	**886**
10	621	799	774	508	702	1,110	1,142	1,045	1,193	1,352	1,276	1,028	**963**
11	669	867	820	547	772	1,217	1,246	1,131	1,291	1,459	1,386	1,145	**1,046**
12	693	894	840	547	787	1,259	1,306	1,193	1,330	1,496	1,440	1,198	**1,082**
13	701	903	835	541	773	1,264	1,339	1,235	1,360	1,494	1,424	1,158	**1,086**
14	676	861	786	480	736	1,226	1,310	1,214	1,335	1,455	1,325	1,088	**1,041**
15	627	770	677	368	667	1,108	1,235	1,144	1,244	1,489	1,294	1,092	**976**
16	554	635	531	221	578	922	1,065	1,039	1,091	1,276	1,109	942	**830**
17	472	463	407	79	430	697	847	906	873	1,054	893	763	**657**
18	397	327	306	-10	331	557	675	747	675	898	730	592	**519**
19	328	232	221	-75	256	435	540	623	563	770	613	437	**412**
20	249	142	172	-96	247	420	479	554	475	659	507	334	**345**
21	221	117	173	-89	263	439	496	568	474	672	497	300	**344**
22	242	153	205	-53	286	476	538	587	505	711	531	331	**376**
23	283	216	273	20	339	549	608	618	575	757	588	387	**434**
24	332	314	355	107	388	638	702	652	656	870	707	470	**516**
Average by Month	**476**	**540**	**507**	**239**	**493**	**830**	**906**	**839**	**895**	**1,113**	**988**	**762**	

In terms of total monthly availability, the unavailability of Costa Sur 6 has a similar impact to that of the TM generators, as both sensitivities assume a comparable reduction in capacity, approximately 350 MW for Costa Sur 6 and 340 MW for the TM units. From a system availability perspective, however, Costa Sur 6 is already scheduled for a planned outage during part of the study period, whereas the TM units are assumed to be fully available in the base case. As a result, the LOLE and LOLH outcomes differ slightly, with the unavailability of Costa Sur 6 being somewhat less impactful than that of the TM units. Nonetheless, from a resource cost standpoint, baseload units like Costa Sur 6 are typically among the most economical. Therefore, its unavailability could lead to a notable increase in total system costs.

Figure A-9: Monthly Average Availability of Unavailability of Costa Sur 6 Sensitivity



Unavailability of AES powerplant:

This sensitivity analyzes the impact of not having available the AES powerplant (both units) for a full year, representing a 454 MW loss of capacity, being the highest negative impact sensitivity of this study. Despite AES units are having a sightly increase on forced outages recently, continues to be one of the most reliable powerplants of Puerto Rico, which in case these units turn unavailable, will impact drastically the electric system, leaving a huge risk of system adequacy and resilience. When compared to the base case, same as in the sensitivity of Costa Sur 6, there are months that these units have planned outages considered in October 2025 for AES 1 and in February and March 2026 for AES 2, which can noted in the reserves heat map below in Figure A-10 those months the impact on reserves is smaller than the other months.

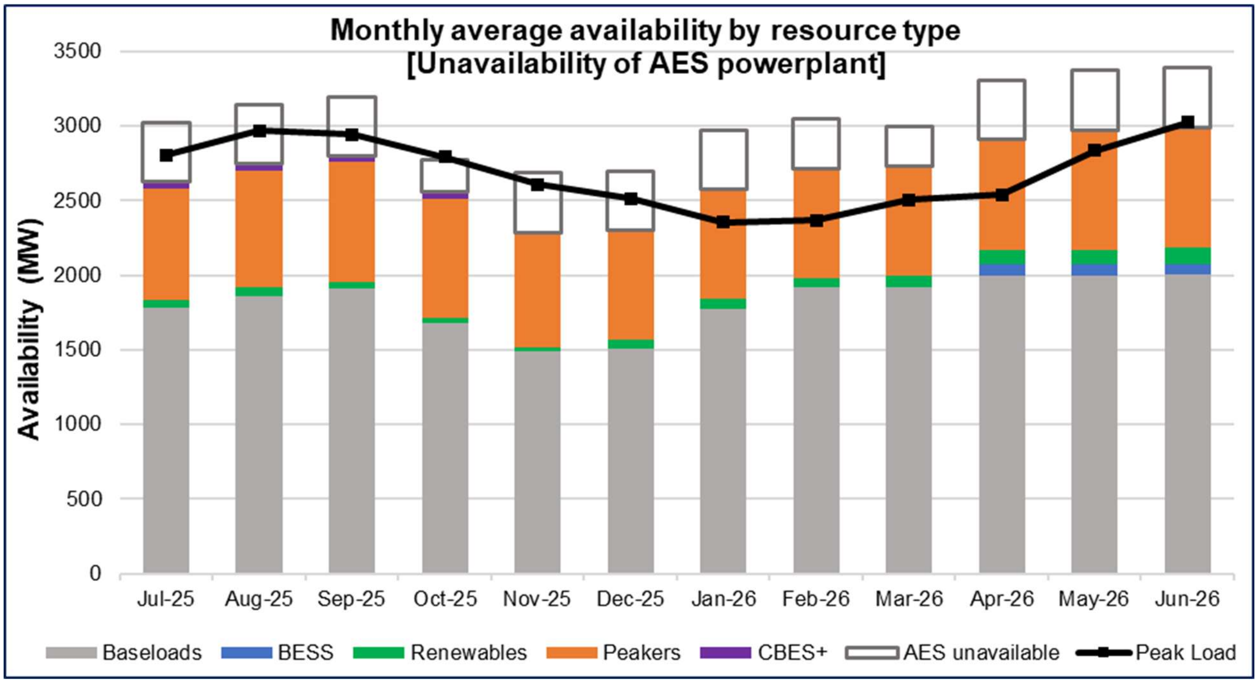
Figure A-10: Unavailability of AES Powerplant Reserves Heat Map

Hour of Day	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Average by Hour
1	296	321	335	259	112	357	693	646	778	878	723	482	**490**
2	347	386	374	316	119	427	767	678	839	956	814	563	**549**
3	371	453	402	348	121	481	827	710	887	1,017	889	615	**593**
4	386	494	422	376	133	517	869	736	919	1,060	929	658	**625**
5	394	517	430	387	134	526	872	740	929	1,070	957	682	**636**
6	388	500	421	371	123	489	824	709	897	1,016	938	674	**613**
7	398	518	437	362	129	442	757	696	872	1,006	956	704	**606**
8	420	561	500	424	197	479	790	743	934	1,108	1,035	786	**665**
9	464	626	588	512	289	601	895	862	1,085	1,265	1,187	935	**776**
10	522	700	675	590	378	747	1,042	1,003	1,225	1,330	1,243	993	**871**
11	570	768	722	629	447	853	1,146	1,088	1,325	1,459	1,380	1,140	**961**
12	594	796	742	630	463	895	1,206	1,151	1,365	1,498	1,439	1,201	**998**
13	601	805	737	624	448	900	1,238	1,193	1,394	1,496	1,422	1,163	**1,002**
14	575	763	688	563	411	863	1,210	1,172	1,369	1,457	1,321	1,091	**957**
15	525	671	579	451	342	744	1,134	1,102	1,279	1,393	1,197	1,007	**869**
16	453	538	432	303	253	557	965	998	1,124	1,179	1,007	847	**721**
17	372	366	309	160	105	332	746	866	905	957	789	666	**548**
18	297	230	210	69	5	193	574	708	707	800	626	494	**409**
19	229	136	126	2	-69	69	438	583	595	673	510	339	**303**
20	151	48	77	-20	-77	55	376	514	507	562	403	235	**236**
21	124	23	77	-13	-61	73	395	528	507	575	393	199	**235**
22	145	57	108	26	-36	110	435	547	538	612	426	229	**266**
23	184	118	174	101	15	183	506	578	608	657	482	285	**324**
24	232	213	256	188	65	272	599	612	689	769	598	365	**405**
Average by Month	**377**	**442**	**409**	**319**	**169**	**465**	**804**	**799**	**928**	**1,033**	**903**	**681**	

As reserves are greatly impacted, system availability is similarly affected. Much like the unavailability of Costa Sur 6, the absence of the AES power plant would not only significantly compromise system reliability but also increase generation costs, as AES operates using the second most economical fuel in the system.

NEPR-MI-2022-0002

Figure A-11: Monthly Average Availability of Unavailability of AES Powerplant Sensitivity



NEPR-MI-2022-0002

Addition of Multiple Resources

This section presents the resource adequacy modeling results from the following sensitivity analyses, which involve the addition of thermal units, solar projects, BESS, and an estimation of perfect capacity for Puerto Rico, including:

- Addition of future solar-only projects (Tranche 1 + non-tranche solar)
- Addition of ASAP BESS projects (SO1)
- Addition of ASAP BESS projects (SO1 + SO2)
- Addition of Genera BESS projects
- Addition of LUMA's 4x25 BESS projects
- Addition of Tranche 1 projects (Solar & BESS)
- Addition of Tranche 1 + ASAP (SO 1 & SO 2) + Genera BESS + LUMA 4x25 BESS
- Addition of Energiza project
- Addition of Genera peakers

As shown in Table A-2 below, the addition of standalone solar resources slightly improves LOLH compared to the Base Case but has minimal impact on LOLE. This is because solar generation is limited to daylight hours. While standalone solar can reduce LOLH during the day, it provides little to no support during evening peak hours (6:00 p.m. to 10:00 p.m.), when system load is highest and load-shed events are most likely to occur.

Standalone BESS resources can help by supplying capacity during peak hours, but their effectiveness depends on having sufficient energy storage. If the system lacks adequate reliability and reserves, BESS units may struggle to fully charge. However, when solar and BESS resources are combined, solar can provide the necessary reserves to charge BESS during the day, allowing full availability during peak demand periods.

Finally, thermal additions offer the most robust improvement to system adequacy, as they can operate at any time of day and are not limited by solar availability or storage constraints.

Table A-2: Calculated Resource Adequacy Risk Measures Associated with Addition of Multiple Resource Sensitivities

Sensitivity Analysis	Loss of Load Expectation (LOLE)	Loss of Load Hours (LOLH)
Base Case	36.9 Days / Year	196.3 Hours / Year
Addition of future solar-only projects (Tranche 1 + non-tranche solar)	36.6 Days / Year	175.5 Hours / Year

NEPR-MI-2022-0002

Sensitivity Analysis	Loss of Load Expectation (LOLE)	Loss of Load Hours (LOLH)
Addition of ASAP BESS project (SO1)	20.5 Days / Year	119.1 Hours / Year
Addition of ASAP BESS project (SO1 & SO2)	10.5 Days / Year	66.0 Hours / Year
Addition of Genera BESS projects	13.2 Days / Year	81.6 Hours / Year
Addition of LUMA 4x25 BESS projects	26.3 Days / Year	146.6 Hours / Year
Addition of Tranche 1 projects (solar & BESS)	7.5 Days / Year	34.7 Hours / Year
Addition of Tranche 1 + ASAP (SO 1 & SO 2) + Genera BESS + LUMA 4x25 BESS	2.0 Days / Year	10.4 Hours / Year
Addition of Energiza	5.3 Days / Year	22.0 Hours / Year
Addition of Genera peakers	12.6 Days / Year	55.9 Hours / Year

Figures A-12 and A-13 below summarize the LOLE probability distributions for all sensitivity scenarios involving the addition of multiple resources, highlighting the variance and impact each resource type has on the electric system.

Figure A-12 compares the effects of adding standalone solar (Tranche 1 and non-Tranche solar), two standalone BESS projects with different capacities (ASAP SO1 and Genera BESS), combined solar and BESS additions (all Tranche 1 projects), and thermal additions (Genera peakers). The sensitivities shown in this figure represent projects with the closest expected commercial operation dates (CODs).

Figure A-13 presents the remaining sensitivities not included in Figure A-12. These include the addition of LUMA's 4x25 BESS, ASAP SO1 and SO2 BESS projects, a combined scenario of all Tranche 1 solar with all expected BESS projects, and the addition of the Energiza CC baseload unit.

NEPR-MI-2022-0002

Figure A-12: Comparison of LOLE Probability Distributions Associated with Addition of Multiple Resources (1/2)

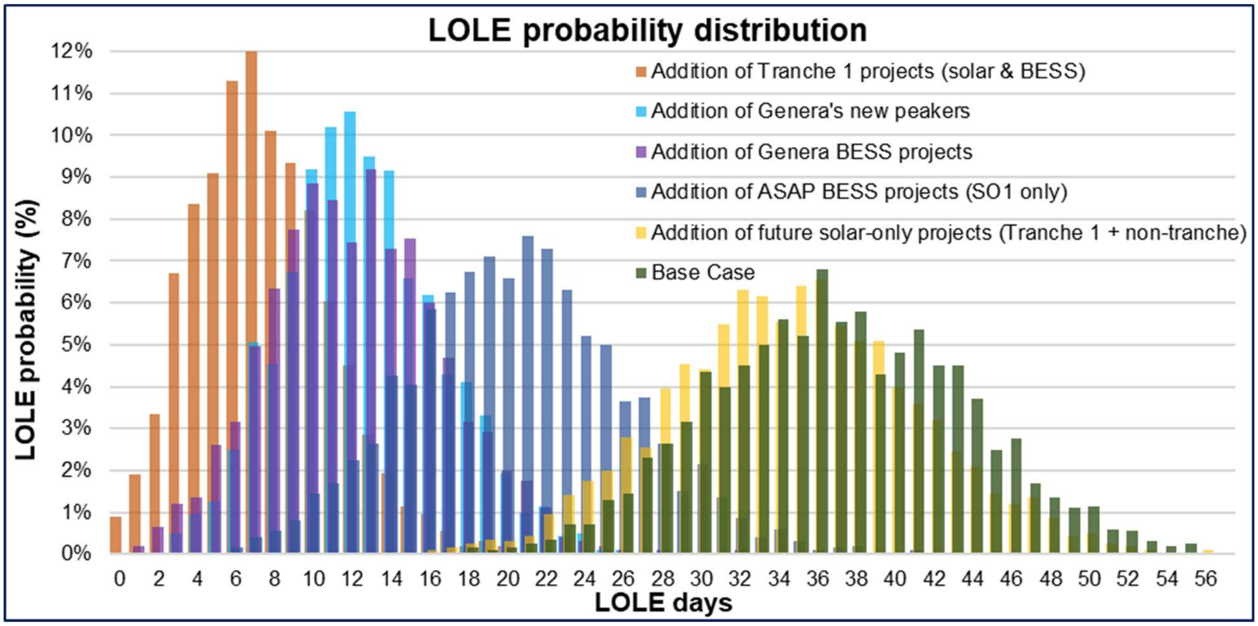
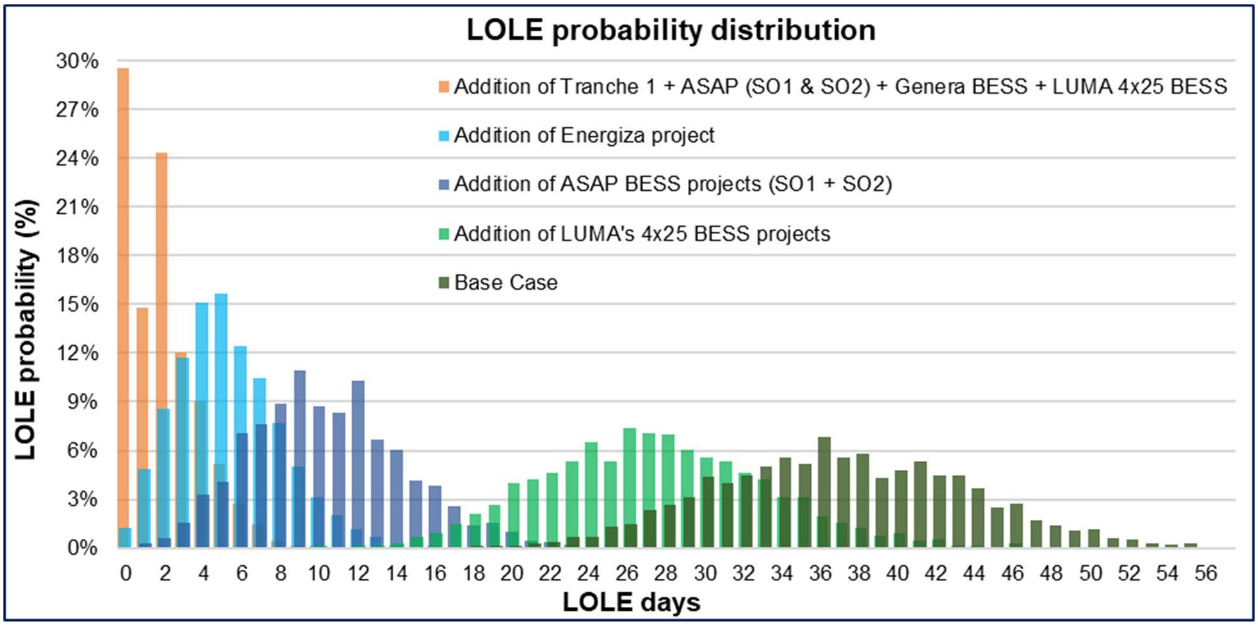


Figure A-13: Comparison of LOLE Probability Distributions Associated with Addition of Multiple Resources (2/2)



Since this group of sensitivities encompasses multiple resource types, each one behaves differently and influences resource adequacy in a unique way based on its operational characteristics. As shown in Figure A-14, standalone solar projects primarily help reduce Loss of Load Hours (LOLH) during daylight hours. In contrast, standalone BESS projects provide a slight improvement in LOLH during the early morning hours. During the day, however, they are generally unavailable as they are charging, and their most significant impact occurs during peak hours, particularly in the early evening and nighttime. In the overall Tranche 1 sensitivity, the hours with the highest LOLH probability shift to midnight through the early morning. This shift reflects the combined effect of renewable resources supplying energy during the day, which allows BESS to charge and be fully available during peak demand periods. Finally, Genera peakers demonstrate a notable improvement in LOLH across all hours of the day, with especially strong performance during the early morning hours when compared to the BESS-only scenarios.

Figure A-14: Comparison of LOLH Associated with Addition of Multiple Resources (1/2)

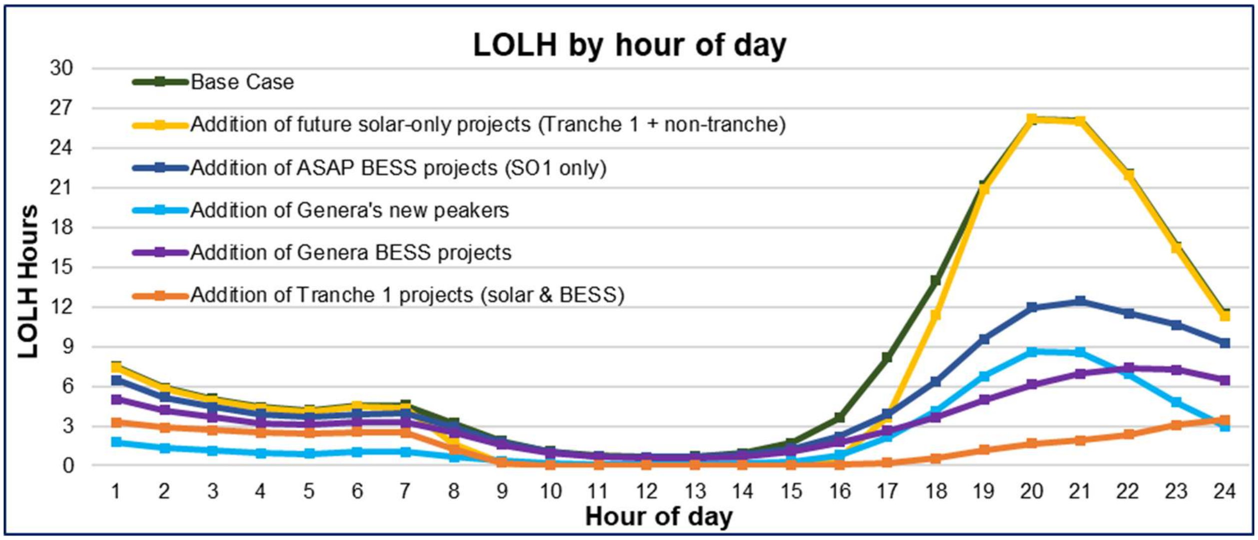
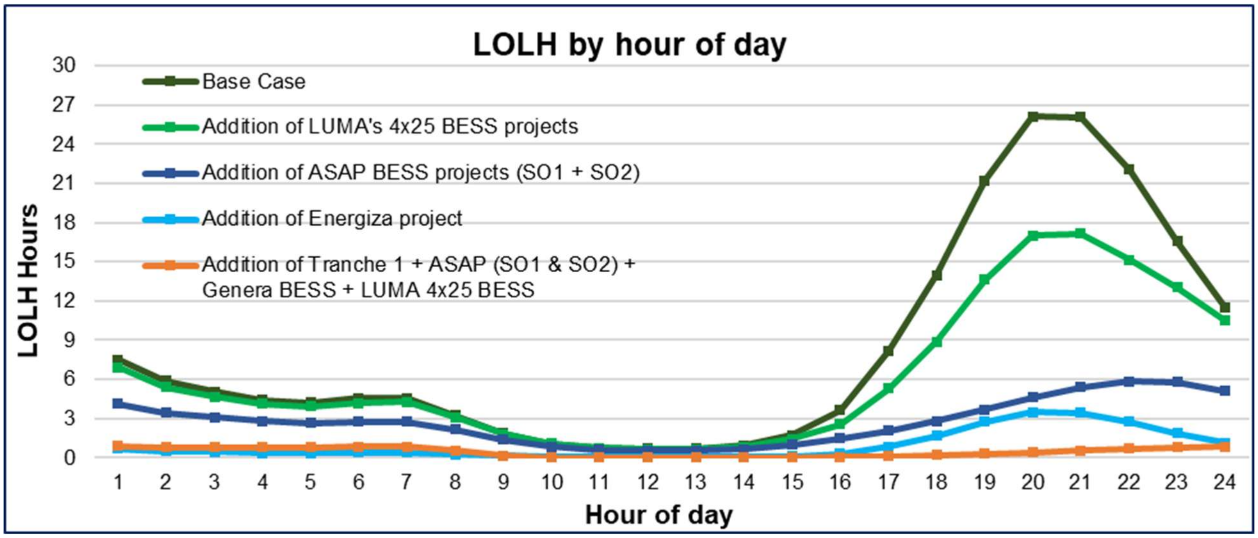


Figure A-15 below presents the hourly LOLH for the remaining sensitivities in this group, showing patterns consistent with those observed in Figure A-14. The combination of Tranche 1 and all BESS projects currently under procurement results in an approximate 95% reduction in LOLH compared to the base case.

NEPR-MI-2022-0002

Figure A-15: Comparison of LOLH Associated with Addition of Multiple Resources (2/2)



Individual Sensitivity Analysis: Addition of Multiple Resources: Addition of Future Solar-Only Projects

When comparing reserve levels between the base case and the scenario with solar-only projects, the biggest difference is seen during daytime reserves. This is because solar projects can only produce energy during daylight hours and don't contribute during the evening peak. This difference in reserves can be seen by comparing Figure A-16 below with Figure 3-8.

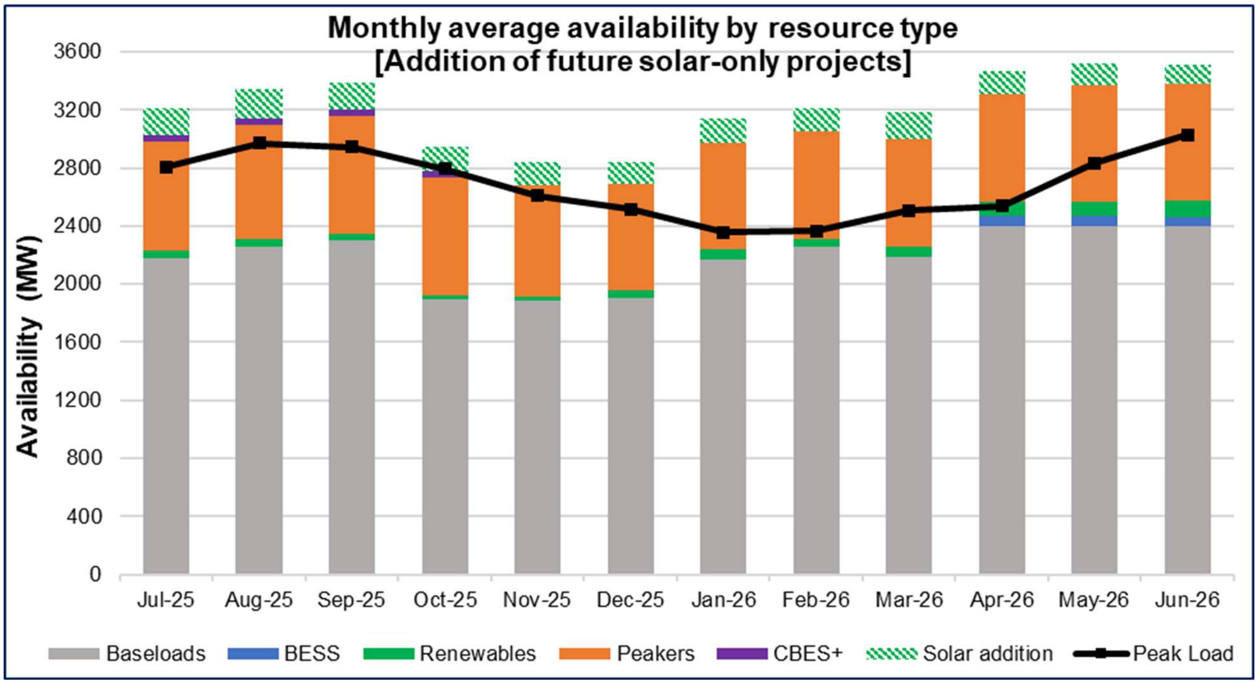
Figure A-16: Addition of Future Solar-Only Resources Reserves Heat Map

Hour of Day	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Average by Hour
1	690	713	727	473	506	753	1,091	985	1,042	1,275	1,128	891	**856**
2	742	777	766	531	513	822	1,165	1,017	1,102	1,353	1,220	973	**915**
3	766	845	794	565	514	876	1,225	1,049	1,150	1,413	1,296	1,024	**960**
4	782	885	814	593	526	912	1,267	1,076	1,182	1,456	1,336	1,066	**991**
5	790	908	821	603	528	920	1,269	1,079	1,192	1,466	1,364	1,090	**1,003**
6	783	892	813	587	517	884	1,221	1,047	1,159	1,412	1,345	1,082	**979**
7	810	923	840	586	525	837	1,154	1,034	1,137	1,413	1,383	1,131	**981**
8	934	1,079	1,036	765	676	919	1,217	1,120	1,284	1,613	1,552	1,295	**1,124**
9	1,143	1,350	1,318	1,047	939	1,205	1,491	1,389	1,624	1,924	1,851	1,571	**1,404**
10	1,346	1,583	1,578	1,271	1,183	1,500	1,811	1,694	1,935	2,035	1,947	1,650	**1,628**
11	1,505	1,777	1,727	1,388	1,371	1,722	2,033	1,884	2,140	2,231	2,139	1,848	**1,814**
12	1,606	1,861	1,804	1,423	1,416	1,828	2,173	2,022	2,225	2,313	2,244	1,947	**1,905**
13	1,616	1,882	1,795	1,427	1,381	1,839	2,230	2,109	2,283	2,311	2,220	1,885	**1,915**
14	1,549	1,800	1,694	1,314	1,293	1,774	2,173	2,059	2,250	2,237	2,068	1,770	**1,832**
15	1,431	1,635	1,451	1,081	1,124	1,562	2,033	1,917	2,080	2,213	1,970	1,735	**1,686**
16	1,233	1,356	1,148	794	916	1,252	1,738	1,709	1,811	1,878	1,675	1,488	**1,416**
17	1,011	1,014	889	507	619	865	1,357	1,442	1,429	1,525	1,354	1,223	**1,103**
18	804	729	658	306	415	605	1,026	1,130	1,069	1,263	1,092	966	**838**
19	643	532	511	207	326	464	836	926	866	1,070	915	746	**670**
20	539	427	458	186	317	449	774	852	772	954	800	629	**596**
21	511	403	460	196	333	469	793	867	773	966	791	595	**596**
22	534	441	494	237	356	506	833	886	804	1,006	826	630	**629**
23	576	506	563	315	408	579	904	916	874	1,051	883	687	**689**
24	627	605	647	404	458	668	997	950	954	1,164	1,005	775	**771**
Average by Month	957	1,038	992	700	715	1,009	1,367	1,298	1,381	1,564	1,434	1,196	

NEPR-MI-2022-0002

Even though this sensitivity contemplates 945 MW of solar capacity, the monthly average availability increases by only approximately 20% when compared to the base case availability (see Figure 3-8). This is due to the expected average capacity factor of solar resources. Solar resources can only reach their nameplate capacity only when there is full solar irradiance that maximizes energy production, which usually happens for just 1-2 hours per day. Figure A-17 below shows the monthly average availability assuming 945 MW of additional solar resources.

Figure A-17: Monthly Average Availability of Addition of Future Solar-Only Resources



Addition of ASAP BESS projects (SO1 & SO2)

Analyzing the addition of the ASAP BESS projects initiated by LUMA, it was considered two sensitivities in were one of them analyzes the addition of the SO1 only, while the other sensitivity analyzes the integration of SO1 and SO2. For SO1, a total of 188 MW of capacity was assumed, corresponding to the total capacity of the proposed participants of this SO1. For the SO2 integration, an additional 574 MW of BESS was assumed, totaling 762 MW of additional BESS. As will be mentioned in Appendix B, charging hours were assumed to be between 10:00 a.m. to 2:00 p.m. in normal conditions, at a rate equal to 80% of their capacity (150 MWh for SO1, 610 MWh in the case for SO1 & SO2). The 80% of their capacity was used because it was assumed to leave the batteries at a minimum of 20% of State of Charge (details can be found in Appendix B). For discharge hours, it was assumed the period from 6:00 p.m. to 10:00 p.m. during normal conditions, same as the charge rate, at an 80% of their capacity, resulting in additional 150 MW of availability at peak hours for SO1, and 610 MW for SO1 & SO2). Since BESS were simulated to charge from the grid, they will use reserves energy to charge, meaning that, when compared to the base case, capacity reserves during the charging hours will see a decrease, so BESS can store that energy to use it at peak hours that is when demand is higher.

NEPR-MI-2022-0002

It can be noticed that in the case of having SO1 & SO2, capacity reserves levels during charging hours are the lowest of the day due to the big amount of BESS charging all at the same time. For modeling consistency, the same charge and discharge hours were assumed for all BESS sensitivities, independent of the total capacity simulated. Since the total capacity used for each sensitivity includes multiple sites, when they start operations in a future, each site could charge and discharge their batteries at different hours of what was assumed in this study.

Figure A-18: Addition of ASAP SO1 BESS Reserves Heat Map

Hour of Day	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Average by Hour
1	830	862	873	598	645	900	1,242	1,132	1,192	1,427	1,280	1,039	1,002
2	883	926	912	655	652	969	1,316	1,164	1,253	1,506	1,372	1,120	1,061
3	907	994	940	687	654	1,022	1,376	1,195	1,301	1,566	1,448	1,172	1,105
4	922	1,034	960	715	665	1,057	1,417	1,221	1,333	1,608	1,488	1,214	1,136
5	931	1,056	968	725	666	1,065	1,420	1,225	1,343	1,618	1,516	1,238	1,148
6	925	1,039	959	709	655	1,030	1,371	1,193	1,309	1,564	1,496	1,229	1,123
7	933	1,056	974	699	660	983	1,304	1,179	1,285	1,554	1,515	1,258	1,117
8	954	1,099	1,038	761	727	1,019	1,337	1,226	1,347	1,657	1,593	1,340	1,175
9	999	1,162	1,126	849	819	1,141	1,441	1,346	1,498	1,813	1,745	1,489	1,286
10	774	948	922	666	641	991	1,289	1,189	1,339	1,497	1,421	1,171	1,071
11	820	1,015	968	703	706	1,097	1,392	1,276	1,437	1,603	1,530	1,287	1,153
12	844	1,044	989	708	722	1,141	1,453	1,339	1,476	1,642	1,585	1,341	1,190
13	852	1,062	989	715	715	1,153	1,487	1,381	1,507	1,641	1,572	1,309	1,198
14	869	1,070	989	699	719	1,162	1,504	1,405	1,528	1,648	1,522	1,293	1,201
15	1,072	1,232	1,143	785	876	1,310	1,717	1,625	1,725	1,976	1,782	1,583	1,402
16	1,021	1,113	1,006	670	812	1,135	1,550	1,522	1,575	1,761	1,590	1,424	1,265
17	942	943	882	532	670	911	1,333	1,390	1,357	1,538	1,373	1,243	1,093
18	868	805	780	438	575	771	1,162	1,230	1,159	1,381	1,211	1,071	954
19	804	707	693	374	507	650	1,026	1,106	1,046	1,254	1,095	917	848
20	721	612	641	349	496	636	965	1,036	958	1,144	988	815	780
21	692	586	641	356	510	654	983	1,050	958	1,157	980	780	779
22	714	624	677	394	531	690	1,024	1,069	991	1,196	1,015	814	812
23	723	658	713	444	551	726	1,058	1,064	1,024	1,204	1,036	837	836
24	773	754	793	529	599	814	1,150	1,098	1,104	1,316	1,156	923	917
Average by Month	866	933	899	615	657	959	1,305	1,236	1,294	1,511	1,388	1,163	

NEPR-MI-2022-0002

Figure A-19: Addition of ASAP SO1 & SO2 BESS Reserves Heat Map

Hour of Day	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Average by Hour
1	1,271	1,325	1,338	1,026	1,076	1,368	1,699	1,595	1,652	1,888	1,746	1,508	1,458
2	1,323	1,388	1,377	1,081	1,082	1,437	1,774	1,627	1,712	1,967	1,837	1,589	1,516
3	1,347	1,456	1,405	1,112	1,082	1,491	1,835	1,660	1,760	2,027	1,913	1,641	1,561
4	1,363	1,496	1,425	1,139	1,091	1,527	1,877	1,686	1,792	2,071	1,953	1,684	1,592
5	1,370	1,519	1,431	1,150	1,090	1,534	1,879	1,689	1,803	2,081	1,981	1,708	1,603
6	1,363	1,503	1,422	1,133	1,077	1,498	1,831	1,657	1,770	2,028	1,962	1,701	1,579
7	1,372	1,520	1,437	1,123	1,081	1,451	1,763	1,644	1,747	2,018	1,981	1,730	1,572
8	1,394	1,564	1,501	1,184	1,146	1,487	1,795	1,691	1,811	2,120	2,058	1,811	1,630
9	1,439	1,628	1,588	1,271	1,237	1,610	1,900	1,810	1,963	2,277	2,210	1,960	1,741
10	424	555	526	372	356	581	839	752	891	1,042	967	727	669
11	453	611	567	400	389	680	940	832	988	1,149	1,082	846	745
12	471	659	595	425	401	740	1,002	893	1,034	1,192	1,152	929	791
13	482	703	610	455	399	771	1,040	935	1,071	1,194	1,155	929	812
14	568	823	717	516	456	901	1,187	1,082	1,223	1,336	1,243	1,052	925
15	1,268	1,641	1,523	935	948	1,781	2,254	2,142	2,276	2,546	2,348	2,130	1,816
16	1,379	1,589	1,466	936	1,026	1,657	2,106	2,073	2,139	2,333	2,159	1,981	1,737
17	1,361	1,451	1,374	877	980	1,455	1,892	1,950	1,925	2,112	1,945	1,807	1,594
18	1,319	1,331	1,291	825	933	1,327	1,723	1,796	1,728	1,955	1,784	1,639	1,471
19	1,372	1,276	1,264	901	1,048	1,224	1,592	1,681	1,620	1,829	1,669	1,491	1,414
20	1,286	1,178	1,209	866	1,031	1,207	1,531	1,611	1,532	1,718	1,562	1,387	1,343
21	1,252	1,149	1,208	862	1,035	1,225	1,550	1,625	1,531	1,730	1,553	1,352	1,339
22	1,268	1,185	1,239	892	1,044	1,260	1,591	1,643	1,563	1,769	1,587	1,384	1,369
23	1,179	1,122	1,177	875	985	1,196	1,514	1,525	1,484	1,664	1,501	1,305	1,294
24	1,228	1,219	1,259	958	1,032	1,284	1,607	1,560	1,564	1,776	1,622	1,393	1,375
Average by Month	1,148	1,245	1,206	888	918	1,279	1,613	1,548	1,608	1,826	1,707	1,487	

Adding 188 MW of BESS corresponding to ASAP SO1, it can be noticed in Figure A-20 below that it is a considerable availability addition that would help Puerto Rico Electric System reliability, specially noted for October, where the base case expected average availability for October is below than the forecasted peak load, and with the ASAP SO1 addition, that average availability surpasses the peak load, creating adequacy of resources. Adding the SO2 also, it can be noticed how far the availability increases as we assume those 762 MW of BESS capacity being online in the system. However, adding this BESS capacity in the actual system, is probable that the BESS could not be fully able to provide its 100% of energy since I would be needed a big amount of reserves to fully charge all the batteries, unless some charging hours are deferred from the assumed charging hours (For example, half of BESS charges from 2:00 a.m. to 6:00 a.m. and the other half charges from 10:00 a.m. to 2:00 p.m.).

NEPR-MI-2022-0002

Figure A-20: Monthly Average Availability of Addition of ASAP SO1 BESS Resources

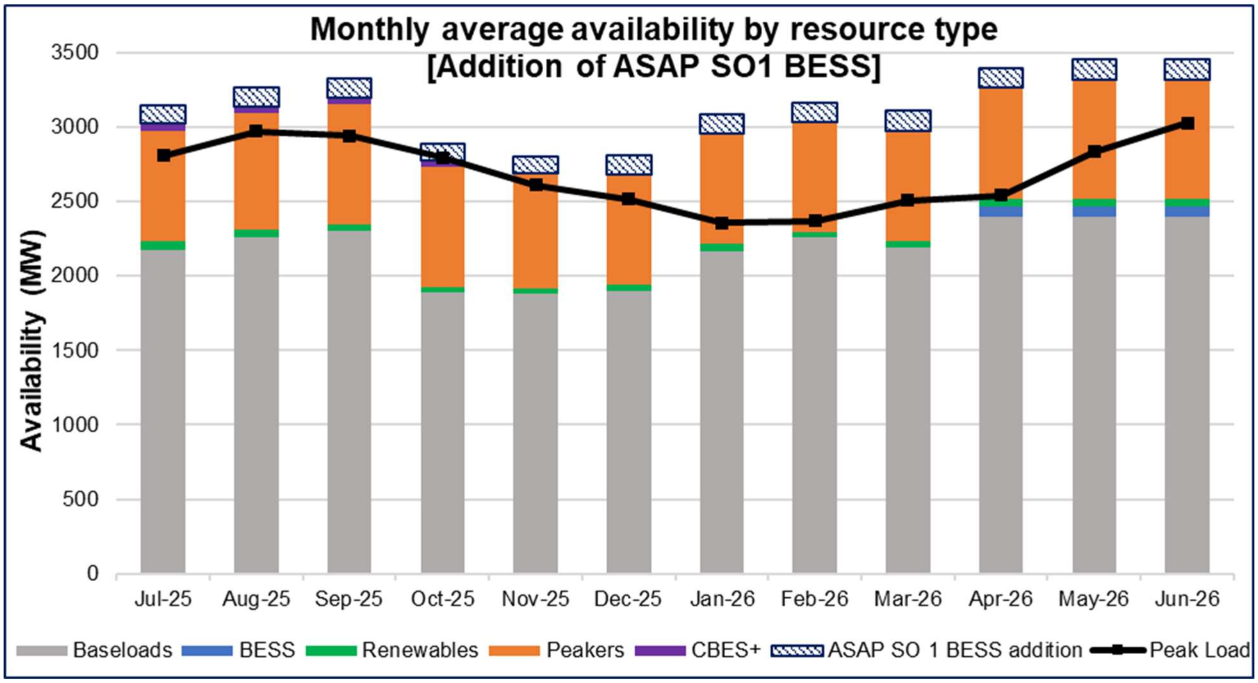
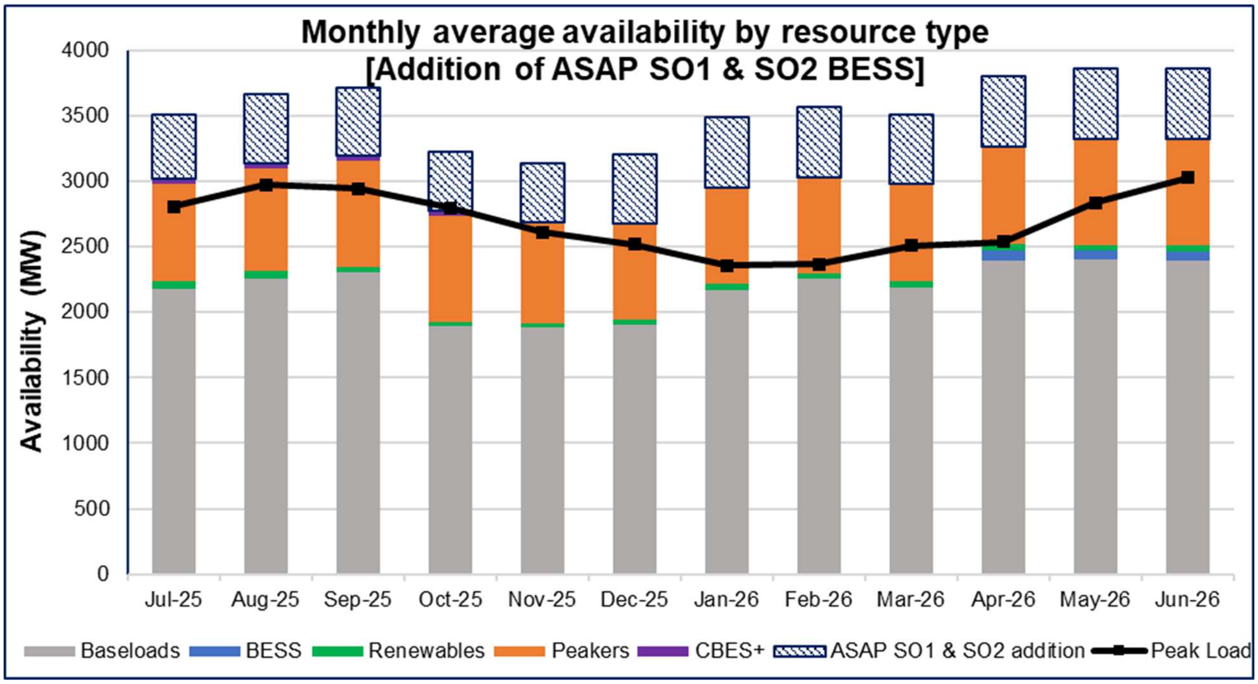


Figure A-21: Monthly Average Availability of Addition of ASAP SO1 & SO2 BESS Resources



Addition of Genera BESS projects

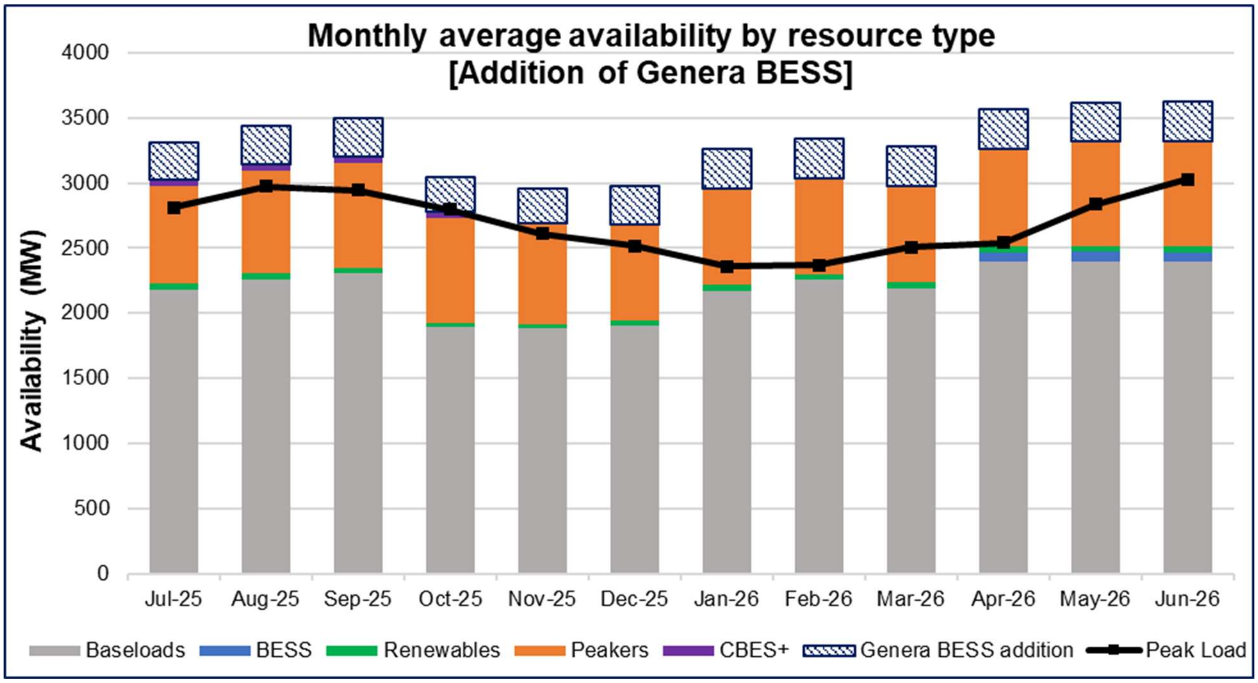
For this sensitivity, 430 MW of BESS capacity were assumed as part of Genera's initiative of adding BESS resources to the system. Taking the assumptions of charge hours from 10:00 a.m. to 2:00 p.m., discharge hours from 6:00 p.m. to 10:00 p.m., leaving the SoC of the batteries at 20% after discharge, and always maintaining system capacity reserves >300 MW, the LOLE reduction resulted from 36.9 in the base case, to 13.2 days, representing a 64% reduction of loss of load. As it is with all BESS sensitivities, hourly capacity reserves see a reduction at the determined BESS charge hours (10:00 a.m. – 2:00 p.m.), and an increase of reserves during peak hours, when BESS were assumed to dispatch energy.

Figure A-22: Addition of Genera BESS Reserves Heat Map

Hour of Day	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Average by Hour
1	1,014	1,052	1,071	784	831	1,096	1,437	1,327	1,383	1,618	1,472	1,235	1,193
2	1,066	1,116	1,110	840	837	1,165	1,512	1,359	1,443	1,696	1,563	1,317	1,252
3	1,089	1,183	1,137	873	837	1,219	1,572	1,391	1,491	1,757	1,640	1,368	1,296
4	1,105	1,222	1,157	901	847	1,254	1,614	1,417	1,523	1,800	1,680	1,410	1,327
5	1,112	1,244	1,165	910	847	1,262	1,616	1,420	1,533	1,809	1,708	1,434	1,339
6	1,106	1,227	1,157	893	835	1,226	1,568	1,389	1,501	1,755	1,688	1,427	1,314
7	1,116	1,244	1,172	884	839	1,178	1,502	1,376	1,477	1,745	1,707	1,457	1,308
8	1,137	1,288	1,236	946	905	1,214	1,533	1,424	1,540	1,847	1,785	1,538	1,366
9	1,182	1,353	1,324	1,034	997	1,337	1,638	1,543	1,693	2,003	1,937	1,687	1,477
10	605	764	745	521	493	805	1,098	1,000	1,145	1,300	1,225	979	890
11	647	828	791	557	548	912	1,201	1,084	1,243	1,405	1,336	1,097	971
12	671	869	819	579	568	968	1,264	1,148	1,287	1,445	1,397	1,163	1,015
13	684	905	829	601	566	991	1,300	1,192	1,323	1,447	1,393	1,148	1,032
14	745	970	883	634	611	1,060	1,375	1,272	1,401	1,512	1,404	1,193	1,088
15	1,233	1,436	1,357	931	1,004	1,535	1,956	1,860	1,965	2,212	2,022	1,822	1,611
16	1,220	1,327	1,233	843	976	1,366	1,791	1,762	1,815	1,996	1,831	1,663	1,485
17	1,151	1,164	1,115	725	857	1,147	1,573	1,631	1,596	1,775	1,614	1,485	1,319
18	1,083	1,030	1,016	641	772	1,009	1,402	1,474	1,399	1,618	1,451	1,314	1,184
19	1,042	940	937	601	739	889	1,267	1,351	1,287	1,491	1,335	1,160	1,087
20	957	844	884	572	726	874	1,206	1,281	1,199	1,381	1,228	1,057	1,017
21	927	817	883	576	737	892	1,224	1,294	1,197	1,394	1,219	1,021	1,015
22	947	856	917	614	756	928	1,264	1,313	1,228	1,433	1,254	1,054	1,047
23	912	850	910	633	738	923	1,250	1,259	1,214	1,394	1,229	1,033	1,029
24	962	946	992	716	786	1,011	1,343	1,293	1,294	1,507	1,349	1,121	1,110
Average by Month	988	1,061	1,035	742	777	1,094	1,438	1,369	1,424	1,639	1,519	1,299	

Assuming adding the Genera BESS to the actual system, improves considerably the availability month by month, resulting every month in more average availability than peak load, giving more reliability to the system.

Figure A-23: Monthly Average Availability of Addition of Genera BESS



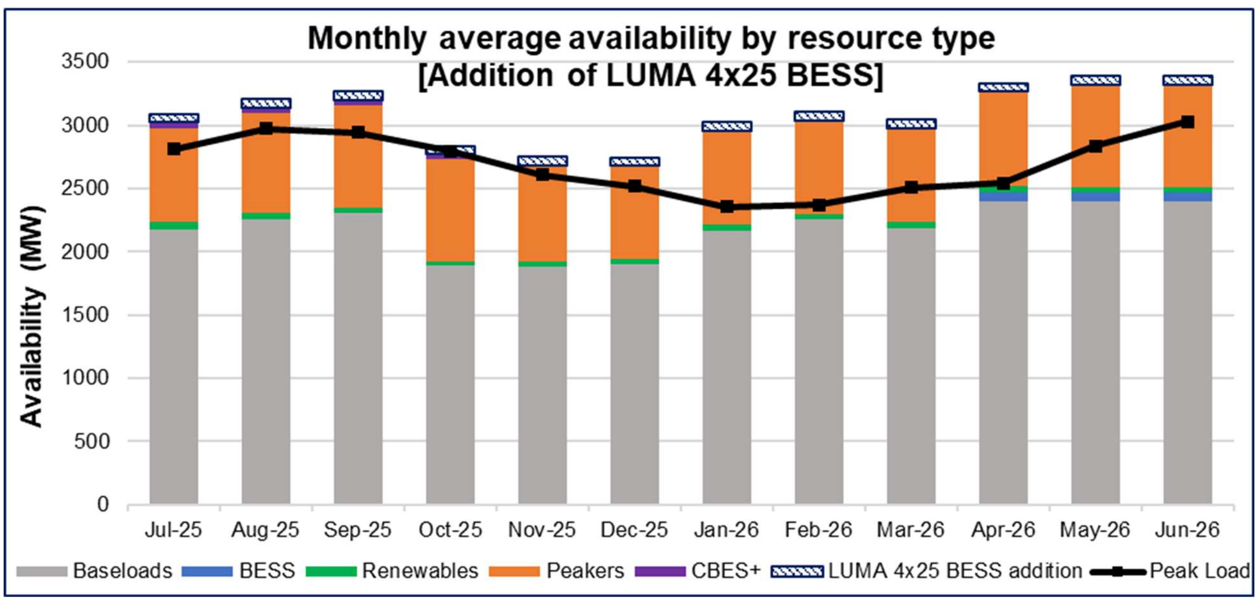
Addition of LUMA 4x25 BESS projects

For this sensitivity, 100 MW of BESS capacity were assumed as part of LUMA's initiative of adding BESS resources to the system. Besides total BESS capacity considered, the other assumptions used are the same as the previous BESS sensitivities analyzed. As per the rule-of-thumb, this BESS sensitivity is the smallest in capacity and hence, the less impactful in terms of resource adequacy improvement.

Figure A-24: Addition of LUMA 4x25 BESS Reserves Heat Map

Hour of Day	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Average by Hour
1	768	798	804	534	579	830	1,167	1,063	1,121	1,353	1,209	971	933
2	820	861	843	590	585	899	1,241	1,094	1,182	1,431	1,301	1,051	992
3	845	928	871	623	587	953	1,302	1,126	1,231	1,492	1,377	1,103	1,036
4	860	967	891	652	598	988	1,344	1,152	1,263	1,535	1,417	1,146	1,068
5	867	989	899	663	600	997	1,347	1,156	1,273	1,544	1,445	1,169	1,079
6	861	973	890	646	589	960	1,299	1,124	1,241	1,491	1,426	1,161	1,055
7	870	990	905	637	594	913	1,232	1,112	1,217	1,480	1,444	1,190	1,049
8	893	1,033	969	699	662	948	1,265	1,159	1,280	1,582	1,523	1,270	1,107
9	937	1,097	1,058	787	754	1,071	1,370	1,278	1,433	1,739	1,674	1,420	1,218
10	845	1,020	992	728	701	1,060	1,357	1,260	1,414	1,564	1,492	1,240	1,139
11	892	1,088	1,038	766	769	1,166	1,460	1,346	1,511	1,669	1,602	1,357	1,222
12	916	1,116	1,057	766	784	1,209	1,520	1,409	1,549	1,707	1,655	1,411	1,258
13	924	1,127	1,054	763	772	1,215	1,553	1,451	1,579	1,704	1,641	1,373	1,263
14	920	1,110	1,031	728	758	1,203	1,549	1,454	1,578	1,689	1,569	1,334	1,243
15	1,007	1,156	1,064	724	812	1,228	1,627	1,538	1,641	1,882	1,697	1,498	1,323
16	945	1,032	923	598	738	1,050	1,459	1,434	1,490	1,667	1,504	1,336	1,181
17	864	859	797	456	594	825	1,241	1,302	1,271	1,444	1,287	1,156	1,008
18	789	721	694	363	496	686	1,070	1,144	1,073	1,288	1,124	985	869
19	720	624	606	294	424	563	934	1,019	961	1,162	1,008	831	762
20	638	530	555	271	415	549	873	951	873	1,052	901	728	695
21	610	505	557	277	430	567	891	964	873	1,065	892	694	694
22	632	544	591	317	452	603	932	983	903	1,105	926	727	726
23	657	593	642	378	486	656	983	994	953	1,130	965	767	767
24	707	689	724	464	533	744	1,075	1,029	1,033	1,243	1,085	855	849
Average by Month	825	890	852	572	613	912	1,254	1,189	1,248	1,459	1,340	1,116	

Figure A-25: Monthly Average Availability of Addition of ASAP LUMA 4x25 BESS



Addition of Tranche 1 projects (Solar & BESS)

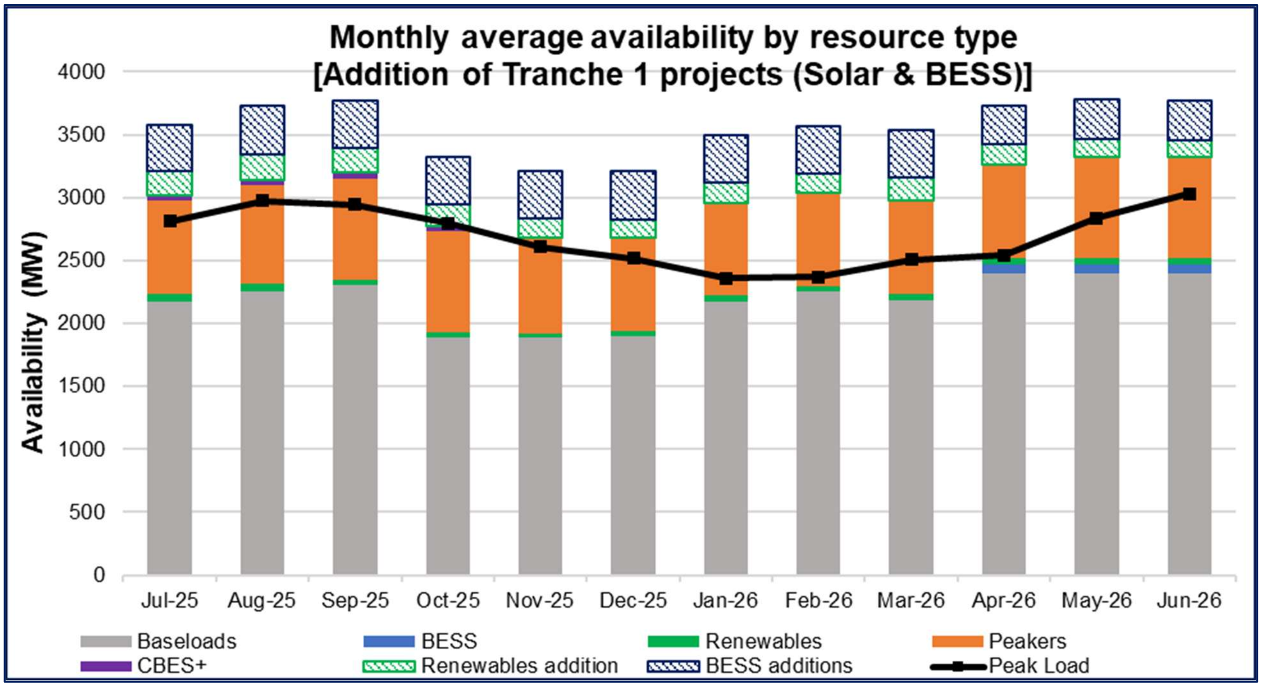
As seen in the previously discussed sensitivities above in this Appendix, solar resources' impact is increasing daytime generation and hence, reserves. BESS resources use daytime reserves (moment of the day were reserves ae higher) to store energy to be used at peak hours, making a greater impact on resource adequacy than solar resources. In this sensitivity, the whole tranche 1 projects were analyzed and assumed to be online with the actual electric system, having approximately 945 MW of solar additions (745 MW from tranche 1 + 200 MW from non-tranche solar projects) + 535 MW of BESS capacity. The combination of solar resources with BESS resources makes a much reliable system because the combination of solar generation increasing further the reserves levels during daytime, so BESS resources could have better chance to fully charge and hence be fully available for peak hours. As can be seen in Figure A-26, capacity reserves would be on average above 650 MW of reserves, meaning that having the whole tranche 1 online in the actual system will significantly improve the electric system.

Figure A-26: Addition of Tranche 1 Projects (Solar & BESS) Reserves Heat Map

		Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Average by Hour
Hour of Day	1	1,108	1,152	1,167	894	936	1,187	1,519	1,414	1,472	1,625	1,482	1,249	1,267
	2	1,160	1,215	1,205	949	941	1,255	1,594	1,445	1,532	1,704	1,573	1,329	1,325
	3	1,185	1,282	1,233	981	941	1,309	1,654	1,477	1,580	1,765	1,649	1,381	1,370
	4	1,199	1,322	1,253	1,008	951	1,345	1,696	1,504	1,611	1,807	1,689	1,422	1,401
	5	1,207	1,344	1,260	1,018	951	1,353	1,698	1,507	1,622	1,817	1,716	1,446	1,411
	6	1,200	1,328	1,252	1,000	939	1,317	1,651	1,476	1,589	1,763	1,697	1,438	1,387
	7	1,227	1,358	1,278	999	944	1,270	1,582	1,464	1,567	1,763	1,735	1,486	1,390
	8	1,351	1,514	1,474	1,177	1,095	1,352	1,644	1,549	1,714	1,964	1,904	1,650	1,532
	9	1,560	1,785	1,757	1,459	1,358	1,637	1,919	1,819	2,053	2,274	2,203	1,926	1,813
	10	925	1,160	1,161	853	773	1,074	1,382	1,268	1,509	1,689	1,599	1,303	1,225
	11	1,084	1,359	1,317	992	966	1,308	1,606	1,456	1,714	1,885	1,794	1,504	1,415
	12	1,200	1,476	1,417	1,088	1,041	1,438	1,751	1,597	1,806	1,970	1,911	1,623	1,526
	13	1,231	1,544	1,433	1,153	1,042	1,477	1,814	1,688	1,874	1,972	1,903	1,591	1,560
	14	1,293	1,600	1,468	1,182	1,088	1,546	1,887	1,765	1,969	2,003	1,861	1,591	1,604
	15	1,920	2,150	1,980	1,536	1,604	2,084	2,565	2,448	2,613	2,650	2,406	2,167	2,177
	16	1,763	1,891	1,688	1,305	1,432	1,784	2,272	2,242	2,340	2,316	2,110	1,922	1,922
	17	1,544	1,551	1,429	1,031	1,149	1,399	1,890	1,976	1,958	1,963	1,790	1,657	1,612
	18	1,338	1,267	1,197	828	949	1,140	1,558	1,664	1,598	1,700	1,527	1,400	1,347
	19	1,177	1,069	1,049	727	861	998	1,368	1,462	1,396	1,506	1,350	1,181	1,179
	20	1,072	960	993	702	851	984	1,306	1,389	1,303	1,391	1,235	1,065	1,104
	21	1,043	935	995	709	865	1,002	1,325	1,402	1,302	1,403	1,226	1,030	1,103
	22	1,066	974	1,030	747	885	1,038	1,365	1,421	1,333	1,442	1,262	1,063	1,136
	23	1,010	950	1,005	746	846	1,014	1,332	1,346	1,300	1,401	1,238	1,045	1,103
	24	1,061	1,046	1,087	827	893	1,102	1,426	1,380	1,381	1,514	1,360	1,134	1,184
	Average by Month	1,247	1,343	1,297	996	1,013	1,309	1,659	1,590	1,672	1,804	1,676	1,442	

When comparing availability additions by resource, BESS shows a significantly higher availability contribution than renewables, primarily due to its higher availability factor and its ability to improve resource adequacy and reliability. The combined availability of Tranche 1 resources approaches that of the peaker units, suggesting a potential reduction in the reliance on costly fuel sources.

Figure A-27: Monthly Average Availability of Addition of Tranche 1 Projects (Solar & BESS)



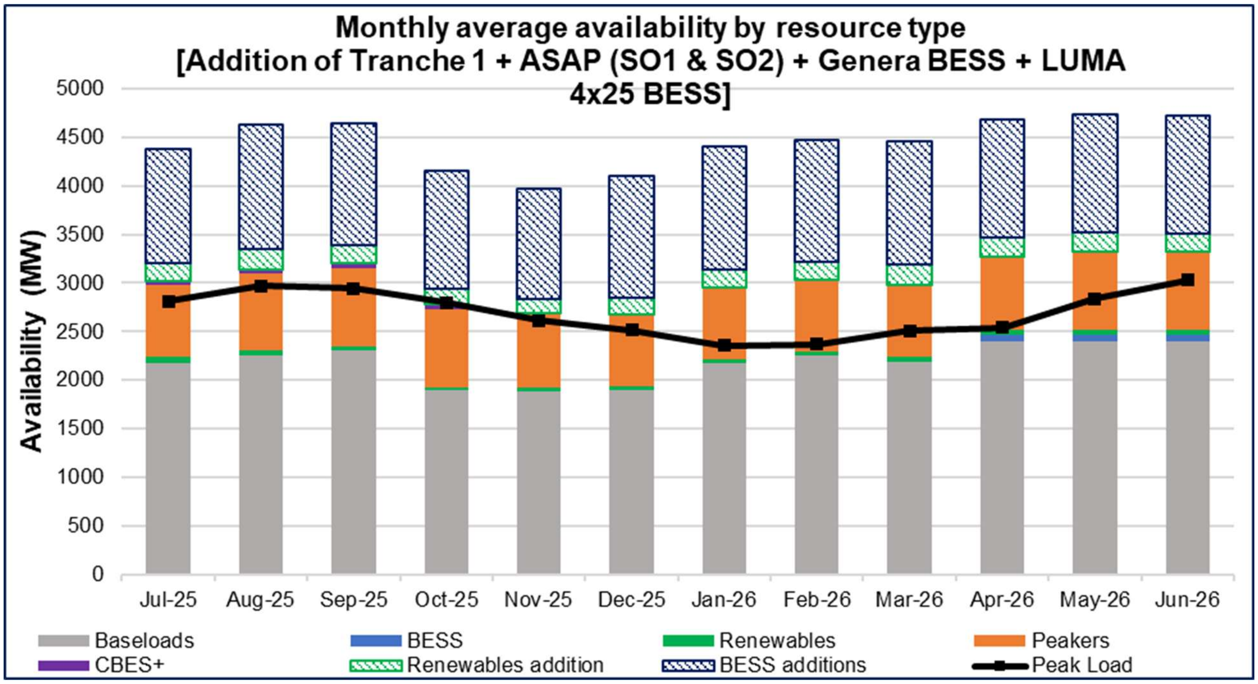
Addition of Tranche 1 + ASAP (SO1 &SO2) + Genera BESS + LUMA 4x25 BESS

This sensitivity assumes the addition of all the non-thermal upcoming utility-scale projects that are being procured to be online in the future. This sensitivity assumes a total of 945 MW of solar additions (745 MW from tranche 1 + 200 MW of non-tranche projects) + 535 MW from tranche 1 BESS + 762 MW from ASAP SO1 & SO2 BESS + 430 MW from Genera BESS + 100 MW of LUMA 4x25 BESS projects, for a total of approximately 1830 MW of BESS resources. As mentioned before in the ASAP SO1 & SO2 sensitivity analysis, for all sensitivities that have BESS additions, charge hours were assumed to be from 10:00 a.m. to 2:00 p.m., which significantly affects reserves during these hours. However, it can be noticed that average reserve levels never reach 300 MW or below, because of an assumed restriction of not charging any battery if reserves are below 300 MW (see Appendix B for more details of this methodology). It is most likely that in the future when these projects come online, Electric System Dispatch chooses other hours of the day to charge all these batteries to prevent leaving the electric system without safe reserve levels and maintain the system as balanced as possible.

Figure A-28: Addition of Tranche 1 + ASAP (SO1 & SO2) + Genera BESS + LUMA 4x25 BESS Reserves Heat Map

Hour of Day	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Average by Hour
1	2,124	2,230	2,224	2,002	1,996	2,250	2,560	2,447	2,511	2,662	2,529	2,310	2,320
2	2,176	2,294	2,261	2,056	2,000	2,319	2,636	2,479	2,572	2,740	2,621	2,391	2,379
3	2,200	2,362	2,289	2,088	1,999	2,373	2,695	2,511	2,621	2,800	2,697	2,442	2,423
4	2,216	2,401	2,308	2,114	2,007	2,408	2,737	2,538	2,653	2,844	2,737	2,485	2,454
5	2,222	2,423	2,317	2,123	2,006	2,417	2,739	2,541	2,663	2,854	2,764	2,507	2,465
6	2,215	2,406	2,308	2,106	1,991	2,381	2,691	2,510	2,629	2,800	2,745	2,499	2,440
7	2,242	2,437	2,334	2,103	1,995	2,334	2,624	2,497	2,608	2,800	2,784	2,548	2,442
8	2,365	2,594	2,530	2,281	2,143	2,416	2,686	2,583	2,754	3,000	2,952	2,712	2,585
9	2,575	2,864	2,812	2,563	2,407	2,701	2,961	2,853	3,094	3,310	3,251	2,988	2,865
10	305	371	356	316	303	343	464	397	549	683	621	421	428
11	331	504	459	405	331	457	628	506	723	866	809	574	549
12	374	674	561	537	367	577	759	613	820	954	953	718	659
13	406	799	622	668	405	658	825	691	897	965	970	748	721
14	502	1,035	816	805	480	847	1,111	931	1,238	1,275	1,204	973	935
15	1,565	2,792	2,423	1,344	965	2,479	3,542	3,191	3,705	3,861	3,546	2,983	2,699
16	2,229	2,941	2,618	1,644	1,419	2,741	3,495	3,380	3,588	3,593	3,357	3,049	2,838
17	2,365	2,719	2,512	1,709	1,584	2,524	3,154	3,199	3,233	3,250	3,061	2,865	2,681
18	2,318	2,485	2,350	1,712	1,636	2,333	2,835	2,915	2,881	2,989	2,807	2,640	2,492
19	2,467	2,359	2,337	2,007	2,143	2,289	2,661	2,750	2,688	2,799	2,643	2,475	2,468
20	2,362	2,250	2,281	1,979	2,130	2,274	2,599	2,677	2,594	2,682	2,527	2,357	2,393
21	2,332	2,224	2,282	1,982	2,138	2,293	2,618	2,690	2,593	2,694	2,518	2,323	2,391
22	2,347	2,264	2,315	2,010	2,131	2,328	2,659	2,708	2,625	2,733	2,553	2,356	2,419
23	2,060	2,024	2,063	1,852	1,907	2,075	2,374	2,379	2,340	2,437	2,284	2,105	2,158
24	2,109	2,123	2,146	1,935	1,953	2,164	2,467	2,413	2,420	2,550	2,406	2,196	2,240
Average by Month	1,850	2,066	1,980	1,681	1,602	1,999	2,355	2,267	2,375	2,506	2,389	2,153	

Figure A-29: Monthly Average Availability of Addition of Tranche 1 + ASAP (SO1 & SO2) + Genera BESS + LUMA 4x25 BESS



NEPR-MI-2022-0002

Addition of Genera Peakers

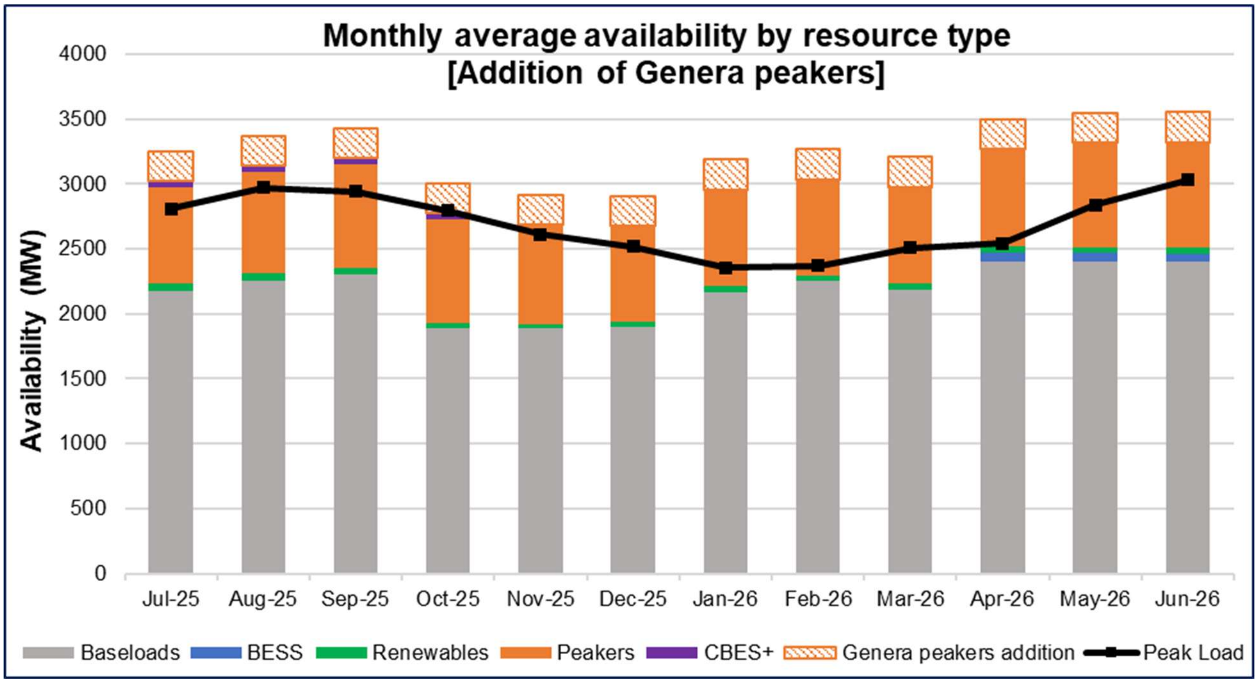
For this sensitivity, a total of 244 MW on thermal peakers resources were added to the actual system, resulting in an overall improvement of reserves for all hours of day. These resources will help the electric system to be ready for high demand periods and as backup in case other units suffer a forced outage at any moment.

Figure A-30: Addition of Genera Peakers Reserves Heat Map

Hour of Day	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Average by Hour
1	923	947	957	702	734	982	1,320	1,217	1,272	1,507	1,362	1,124	1,087
2	976	1,012	996	760	740	1,052	1,394	1,249	1,333	1,586	1,454	1,204	1,146
3	1,000	1,080	1,025	794	742	1,106	1,454	1,281	1,382	1,646	1,530	1,256	1,191
4	1,015	1,120	1,045	822	753	1,141	1,496	1,308	1,413	1,689	1,571	1,299	1,223
5	1,023	1,142	1,052	832	755	1,150	1,499	1,311	1,424	1,699	1,599	1,323	1,234
6	1,017	1,126	1,044	816	745	1,114	1,451	1,280	1,390	1,646	1,580	1,315	1,210
7	1,026	1,143	1,058	806	752	1,066	1,383	1,267	1,367	1,635	1,600	1,345	1,204
8	1,047	1,186	1,121	869	819	1,102	1,415	1,313	1,429	1,738	1,679	1,427	1,262
9	1,092	1,250	1,209	958	912	1,224	1,520	1,433	1,581	1,894	1,831	1,576	1,373
10	1,150	1,324	1,297	1,035	1,000	1,370	1,667	1,574	1,721	1,879	1,806	1,553	1,448
11	1,198	1,392	1,344	1,073	1,070	1,476	1,770	1,660	1,819	1,985	1,916	1,671	1,531
12	1,222	1,421	1,363	1,074	1,087	1,518	1,830	1,723	1,858	2,024	1,970	1,723	1,568
13	1,229	1,430	1,359	1,068	1,072	1,523	1,862	1,765	1,887	2,021	1,954	1,685	1,571
14	1,204	1,387	1,311	1,007	1,035	1,485	1,833	1,744	1,863	1,983	1,855	1,617	1,527
15	1,154	1,295	1,202	894	966	1,365	1,758	1,674	1,773	2,021	1,835	1,644	1,465
16	1,081	1,160	1,055	745	878	1,179	1,589	1,570	1,620	1,803	1,636	1,470	1,315
17	999	986	929	597	729	954	1,369	1,439	1,401	1,581	1,420	1,289	1,141
18	923	847	826	502	630	814	1,197	1,280	1,202	1,424	1,257	1,118	1,002
19	852	748	737	430	556	692	1,063	1,155	1,090	1,297	1,140	964	894
20	770	654	686	408	547	677	1,002	1,085	1,002	1,186	1,033	861	826
21	741	629	687	418	563	696	1,019	1,099	1,001	1,199	1,024	826	825
22	764	669	723	462	586	733	1,061	1,119	1,033	1,238	1,059	859	859
23	808	738	794	543	638	806	1,133	1,149	1,102	1,283	1,117	917	919
24	859	838	878	631	688	897	1,226	1,184	1,183	1,397	1,239	1,007	1,002
Average by Month	1,003	1,064	1,029	760	792	1,088	1,430	1,370	1,423	1,640	1,520	1,295	

In terms of availability, the addition of Genera peakers resulted in a notable improvement mostly due to the assumed forced outage rate of 5% used for these units since this equipment will be new and more efficient than the actual peakers.

Figure A-31: Monthly Average Availability of Addition of Genera Peakers



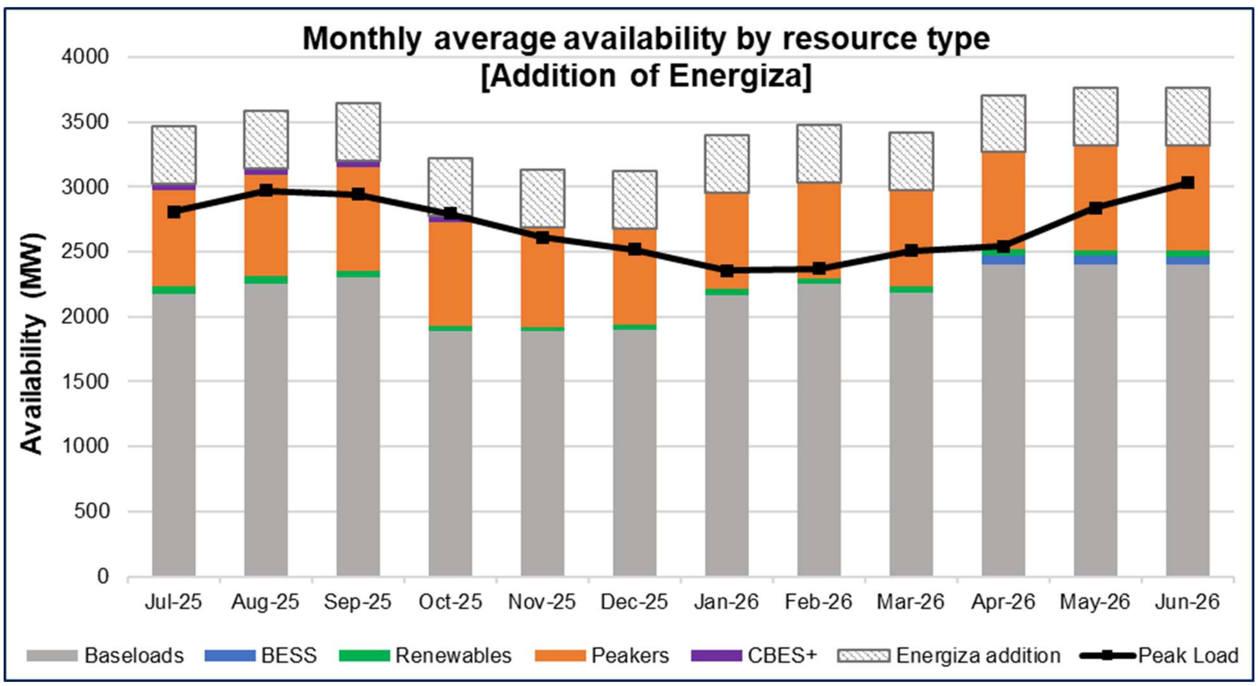
Addition of the Energiza project

For this sensitivity, the addition of the Energiza project to the actual system was considered, adding 478 MW of baseload thermal capacity with a 5% of forced outage rate. The same behavior as the addition of Genera peakers and any thermal resource is seen, resulting in an improvement in reserves and availability during any hour of the day. Any electric system needs at least a certain number of thermal units that can generate electricity at any hour of the day independently of climate, reserves, etc.

Figure A-32: Addition of the Energiza Project Reserves Heat Map

Hour of Day	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Average by Hour
1	1,131	1,155	1,169	914	951	1,193	1,532	1,427	1,484	1,715	1,573	1,337	1,298
2	1,186	1,219	1,208	971	959	1,262	1,606	1,459	1,544	1,794	1,665	1,418	1,358
3	1,210	1,287	1,237	1,005	961	1,316	1,666	1,491	1,592	1,854	1,741	1,469	1,402
4	1,227	1,327	1,256	1,033	972	1,352	1,707	1,517	1,623	1,897	1,782	1,512	1,434
5	1,234	1,350	1,264	1,044	974	1,361	1,709	1,520	1,634	1,907	1,809	1,536	1,445
6	1,227	1,333	1,255	1,028	963	1,325	1,662	1,489	1,601	1,854	1,790	1,528	1,421
7	1,237	1,350	1,271	1,020	969	1,279	1,594	1,476	1,577	1,844	1,808	1,557	1,415
8	1,258	1,393	1,335	1,083	1,036	1,315	1,626	1,524	1,640	1,947	1,888	1,638	1,474
9	1,303	1,457	1,423	1,171	1,129	1,437	1,731	1,643	1,792	2,103	2,039	1,787	1,585
10	1,361	1,533	1,511	1,248	1,217	1,583	1,878	1,784	1,932	2,087	2,015	1,763	1,659
11	1,409	1,600	1,558	1,286	1,287	1,689	1,982	1,870	2,030	2,194	2,125	1,879	1,742
12	1,432	1,628	1,578	1,287	1,302	1,730	2,042	1,932	2,068	2,232	2,179	1,932	1,779
13	1,439	1,638	1,573	1,281	1,287	1,735	2,075	1,975	2,098	2,229	2,163	1,894	1,782
14	1,413	1,594	1,524	1,220	1,251	1,698	2,047	1,954	2,074	2,191	2,066	1,826	1,738
15	1,363	1,503	1,415	1,106	1,181	1,578	1,972	1,883	1,984	2,229	2,047	1,854	1,676
16	1,291	1,369	1,266	957	1,093	1,392	1,803	1,780	1,831	2,012	1,847	1,679	1,527
17	1,208	1,194	1,140	810	944	1,166	1,584	1,647	1,612	1,788	1,630	1,498	1,352
18	1,131	1,054	1,037	714	844	1,026	1,413	1,488	1,415	1,632	1,467	1,326	1,212
19	1,060	956	948	641	770	904	1,277	1,365	1,303	1,504	1,351	1,173	1,104
20	978	862	896	618	761	890	1,216	1,296	1,216	1,394	1,244	1,070	1,037
21	950	836	898	629	778	909	1,234	1,309	1,215	1,406	1,235	1,035	1,036
22	973	877	934	675	801	945	1,274	1,328	1,246	1,444	1,270	1,069	1,070
23	1,017	946	1,005	755	854	1,018	1,345	1,359	1,315	1,489	1,327	1,128	1,130
24	1,068	1,046	1,089	843	904	1,108	1,438	1,392	1,396	1,603	1,449	1,220	1,213
Average by Month	1,213	1,271	1,241	973	1,008	1,300	1,642	1,580	1,634	1,848	1,730	1,505	

Figure A-33: Monthly Average Availability of Addition of the Energiza Project



A.2 Load / Demand Affected Sensitivities

This section presents resource adequacy modeling results from the following sensitivity analyses that involve additions or reductions on the hourly load for FY2026.

- Unavailability of Distributed Generation (DG)
- Addition of Demand Response program: CBES+
- Addition of Demand Response Program: Backup-generators
- Load Increase (+10%)
- Load Decrease (-10%)
- Addition of Electric Vehicle Load

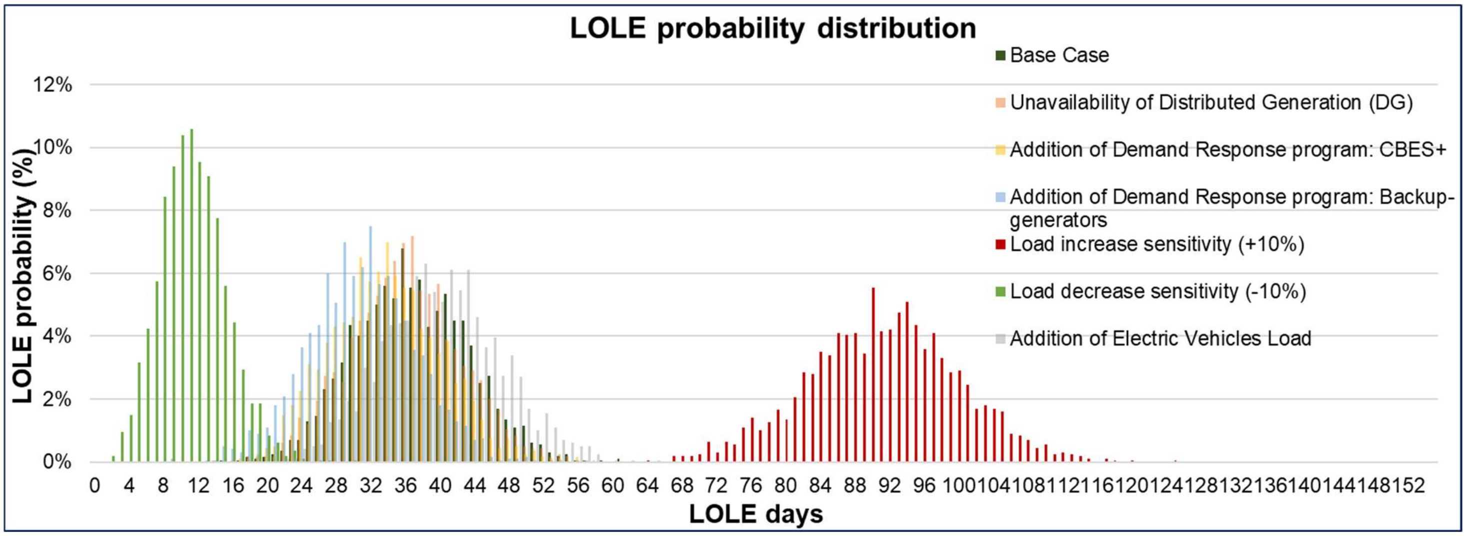
Comparing these sensitivities with the Base Case, the majority does not have a significant impact on resource adequacy, except for the load increase and load decrease sensitivities. As can be seen in Table A-3 below, assuming a load increase of 10%, resource adequacy gets worse by approximately 144% in LOLE events and 191% in LOLH. On the other hand, if the hourly load is decreased by 10%, resource adequacy shows a significant improvement by approximately 69% in LOLE events and 74% in LOLH.

Table A-3: Calculated Resource Adequacy Risk Measures Associated with Load/Demand Affected Sensitivities

Sensitivity Analysis	Loss of Load Expectation (LOLE)	Loss of Load Hours (LOLH)
Base Case	36.9 Days / Year	196.3 Hours / Year
Unavailability of Distributed Generation (DG)	37.2 Days / Year	207.8 Hours / Year
Addition of Demand Response program: CBES+	33.9 Days / Year	183.1 Hours / Year
Addition of Demand Response Program: Backup-generators	32.0 Days / Year	175.4 Hours / Year
Load Increase (+10%)	90.2 Days / Year	571.0 Hours / Year
Load Decrease (-10%)	11.3 Days / Year	51.9 Hours / Year
Addition of Electric Vehicle Load	38.0 Days / Year	202.3 Hours / Year

Figure A-35 shows how the probability distribution of outcomes for LOLE significantly worsens relative to the Base Case if the hourly load is increased by 10%, while if the load is decreased by 10% the probability of experienced LOLE events reduces significantly. On the other hand, the unavailability of DG, the addition of EVs and the demand response programs sensitivities have a minimum impact on LOLE.

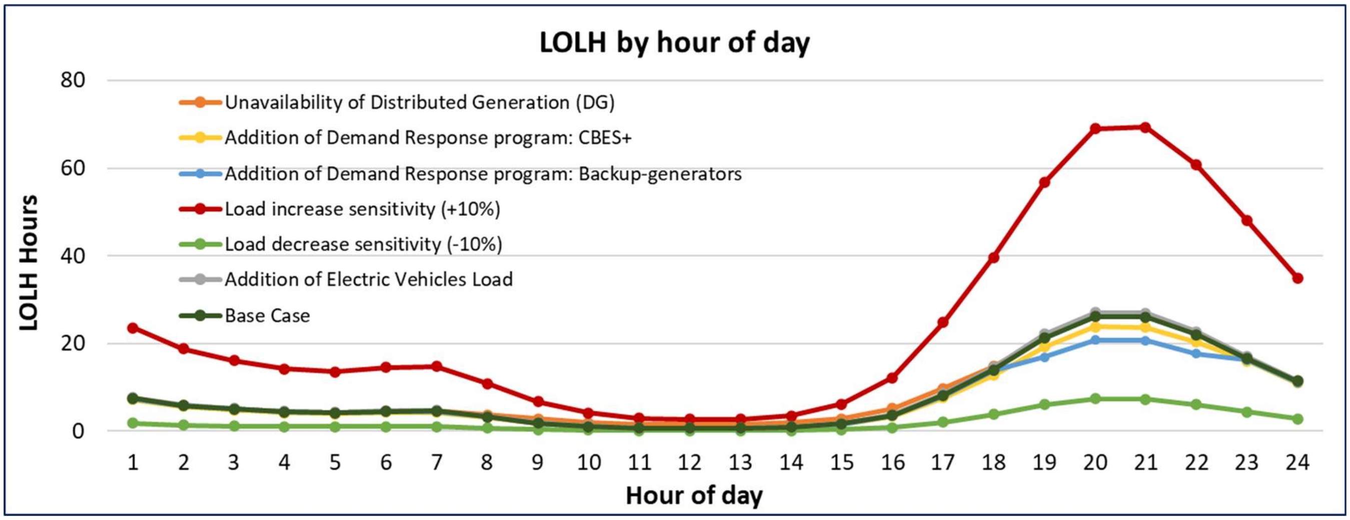
Figure A-35: Comparison of LOLE Probability Distributions Associated with Load/Demand Affected Sensitivities



NEPR-MI-2022-0002

Meanwhile, Figure A-36 indicates how much LOLH varies relative to the Base Case for each of these six sensitivity analyses. The load increase sensitivity (+10%) impact is noted at every hour of the day and having a considerable increase in LOLH during peak hours. On the other hand, the load decrease sensitivity (-10%) reduces the impact in every hour of the day and not going over approximately 10 LOLH hours during the peak load time. Additionally, both demand response programs (CBES+ and backup generators) reduce the LOLH impact specifically in the peak hours.

Figure A-36: Comparison of LOLH Associated with Load/Demand Affected Sensitivities



A.2.1 Individual Sensitivity Analysis: Load / Demand Affected Sensitivities

Unavailability of Distributed Generation (DG):

This sensitivity analyzes the impact of not considering the behind-the-meter (BTM) solar production that residential customers are injecting to the system during the day. Figure A-37 illustrates the average hourly reserve levels for each month of FY2026. It can be noticed that the maximum average reserve level by hour is 1,171 MW at 1:00 p.m., while in the Base Case, according to the heat map in Section 3.1.2, at that same hour the result was 1,340 MW. The difference is tied to the unavailability of DG in this sensitivity. Also, during hours outside the day (where there is no solar production), reserve levels in both heat maps are practically the same.

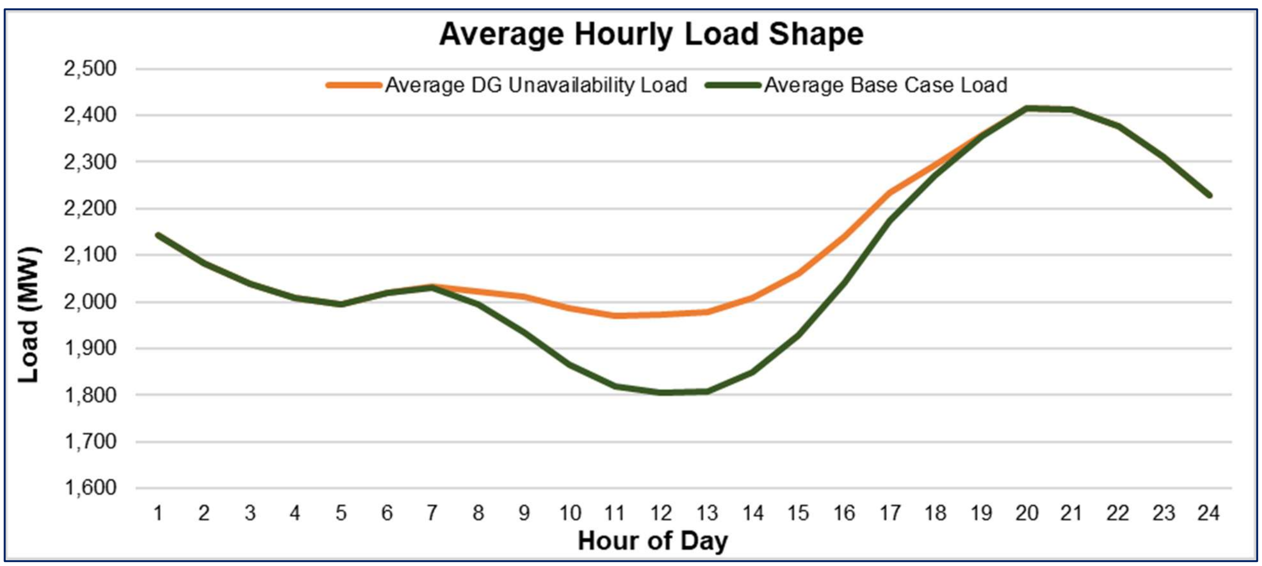
NEPR-MI-2022-0002

Figure A-37: Unavailability of Distributed Generation (DG) Heat Map

Hour of Day	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Average by Hour
1	690	717	732	474	510	749	1,088	984	1,041	1,276	1,126	888	**856**
2	743	781	771	531	515	818	1,164	1,017	1,101	1,354	1,218	969	**915**
3	767	849	800	563	517	873	1,224	1,050	1,148	1,415	1,295	1,021	**960**
4	782	889	819	592	528	908	1,266	1,075	1,180	1,459	1,334	1,064	**991**
5	789	912	827	603	530	917	1,268	1,079	1,190	1,468	1,362	1,088	**1,003**
6	782	895	818	587	519	881	1,220	1,048	1,157	1,414	1,343	1,081	**979**
7	789	910	831	576	524	834	1,153	1,035	1,134	1,400	1,353	1,100	**970**
8	796	934	869	614	571	857	1,176	1,068	1,167	1,459	1,389	1,136	**1,003**
9	817	963	919	660	624	934	1,229	1,139	1,252	1,549	1,470	1,216	**1,064**
10	854	1,012	974	705	676	1,038	1,323	1,226	1,333	1,479	1,390	1,143	**1,096**
11	884	1,058	1,000	728	718	1,111	1,391	1,279	1,394	1,547	1,459	1,216	**1,149**
12	897	1,076	1,009	721	728	1,135	1,426	1,318	1,417	1,566	1,489	1,244	**1,169**
13	903	1,082	1,005	713	718	1,137	1,450	1,344	1,435	1,564	1,477	1,217	**1,171**
14	884	1,046	967	664	694	1,107	1,431	1,333	1,414	1,540	1,404	1,174	**1,138**
15	845	967	884	576	648	1,015	1,374	1,286	1,351	1,604	1,419	1,226	**1,100**
16	790	857	766	457	588	864	1,243	1,216	1,238	1,439	1,269	1,099	**986**
17	728	712	667	342	475	685	1,073	1,127	1,077	1,274	1,102	964	**852**
18	673	598	589	272	400	578	950	1,018	936	1,164	988	840	**750**
19	616	518	512	208	330	460	832	918	855	1,065	901	722	**662**
20	538	428	462	186	321	446	770	850	769	957	800	627	**596**
21	511	404	464	194	337	465	789	864	769	969	790	592	**596**
22	534	443	499	236	360	501	830	884	800	1,008	823	625	**629**
23	577	509	569	315	413	574	901	916	870	1,053	881	682	**688**
24	628	609	653	403	463	664	994	951	951	1,166	1,002	771	**771**
Average by Month	**742**	**799**	**767**	**497**	**529**	**815**	**1,149**	**1,084**	**1,124**	**1,341**	**1,212**	**988**	

The difference between load/demand affected sensitivities and the Base Case can also be noticed directly in the hourly load shape. Figure A-38 shows that when there is no contribution from DG the load (demand) is higher during the day compared to the load shape of the Base Case since that difference in load would be replaced with other resources of the system.

Figure A-38: Average Hourly Load Shape Comparison



NEPR-MI-2022-0002

Addition of Demand Response Programs (CBES+ and Backup Generators):

Demand response (DR) programs involve a region's electric utility being able to call upon retail electricity customers to reduce demand during specified windows of time. The effect of DR appears to the system operator as “negative demand”, which in turn appears equivalent to the addition of supply.

Given that a DR resource would not be continuously available for every hour of the year, DR is assumed for this analysis as being available for up to a maximum of 4 hours in any rolling 24-hour period. Note that this assumption is considered as an approximation of DR availability. Actual operation of DR resources in Puerto Rico might occur differently than assumed in the model, depending upon the capabilities of the DR resource to reduce electrical consumption, the cost of the DR resource, and the specifics of the agreement with the customer, among other items.

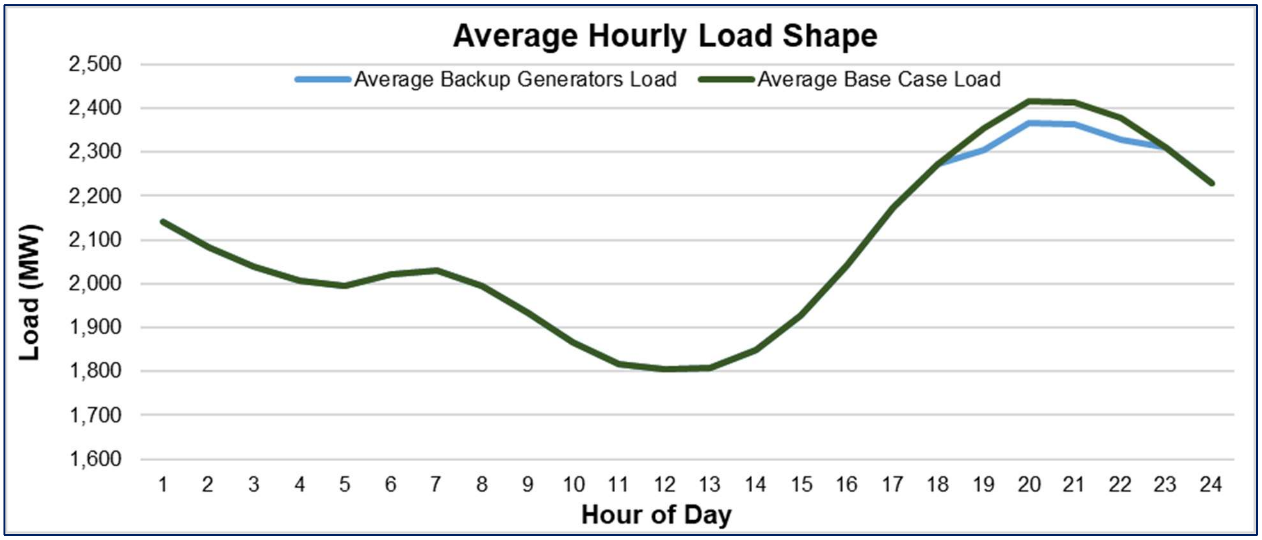
These two sensitivities, with a 100 MW combined total, were analyzed to identify the impact of their contribution at peak hours during the whole FY2026. Essentially, the CBES+ program provides extra capacity to the system, while the backup generators program reduces the system's overall demand by certain customers using their own generated electricity. Figure A-39 shows the average hourly reserve levels of the backup generators sensitivity, and the improvement can be noticed at the peak hours compared to the heat map of the Base Case in Section 3.1.2. For example, in the backup generators sensitivity, the reserve level at the peak hour (20) in October 2025 is about 233 MW while at that same hour and month in the Base Case is 186 MW. The sensitivity of the CBES+ program is not shown here since it’s impact and results are similar to the backup generators sensitivity.

Figure A-39: Demand Response Program (Backup Generators) Heat Map

Hour of Day	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Average by Hour
1	688	716	730	471	507	753	1,087	983	1,041	1,275	1,135	890	**856**
2	742	781	769	528	513	822	1,161	1,015	1,101	1,354	1,226	970	**915**
3	767	848	796	562	515	877	1,220	1,047	1,150	1,414	1,302	1,022	**960**
4	783	889	816	589	526	912	1,262	1,073	1,181	1,458	1,342	1,064	**991**
5	791	912	823	600	529	920	1,265	1,076	1,191	1,468	1,369	1,088	**1,003**
6	784	895	815	583	518	884	1,217	1,044	1,159	1,413	1,349	1,081	**979**
7	794	912	830	574	524	837	1,150	1,032	1,135	1,403	1,367	1,111	**972**
8	816	955	894	637	591	873	1,182	1,079	1,197	1,506	1,445	1,192	**1,031**
9	860	1,019	982	725	684	997	1,286	1,198	1,348	1,662	1,597	1,341	**1,142**
10	917	1,094	1,070	802	773	1,142	1,434	1,339	1,489	1,647	1,575	1,321	**1,217**
11	965	1,162	1,117	841	842	1,249	1,538	1,425	1,586	1,753	1,684	1,438	**1,300**
12	989	1,190	1,137	842	858	1,290	1,598	1,487	1,626	1,791	1,738	1,491	**1,336**
13	995	1,199	1,133	836	843	1,295	1,631	1,530	1,655	1,788	1,722	1,452	**1,340**
14	969	1,157	1,085	777	806	1,257	1,603	1,509	1,630	1,749	1,624	1,384	**1,296**
15	920	1,066	975	664	737	1,138	1,528	1,438	1,540	1,786	1,603	1,406	**1,233**
16	847	932	827	515	648	951	1,359	1,334	1,388	1,570	1,407	1,236	**1,084**
17	765	759	701	371	500	725	1,141	1,202	1,169	1,347	1,190	1,056	**910**
18	689	620	599	278	401	585	969	1,043	970	1,191	1,027	885	**771**
19	668	571	560	255	376	513	884	969	909	1,114	961	781	**713**
20	586	477	509	233	368	499	822	899	821	1,004	854	679	**646**
21	558	453	510	242	384	518	839	913	819	1,017	846	644	**645**
22	581	491	545	284	408	555	880	932	851	1,056	882	676	**678**
23	574	509	567	314	410	578	900	913	870	1,052	889	684	**688**
24	624	607	650	401	460	668	993	948	952	1,165	1,011	773	**771**
Average by Month	**778**	**842**	**810**	**539**	**572**	**868**	**1,206**	**1,143**	**1,199**	**1,416**	**1,298**	**1,069**	

As mentioned above, the impact of these two sensitivities is at peak hours. Figure A-40 compares the System Load of the base case and the sensitivity of backup generators. It can be appreciated that the system demand reduction in the backup generators sensitivity from hour 18 to hour 23 (peak hours).

Figure A-40: Average Hourly Load Shape Comparison



Load Increase (+10%) Sensitivity:

This sensitivity analysis evaluates the impact of a 10% increase in hourly load across the entire FY2026. The purpose is to assess potential effects on resource adequacy in the event that actual demand exceeds forecasts, for example, due to higher temperatures. As shown in Figure A-41, average reserve levels in October 2025 drop into negative values during peak hours, indicating a high likelihood of generation shortfalls under this increased load scenario. Additionally, both hourly and monthly averages show a consistent reduction of 150 to 200 MW compared to the Base Case presented in Section 3.1.2.

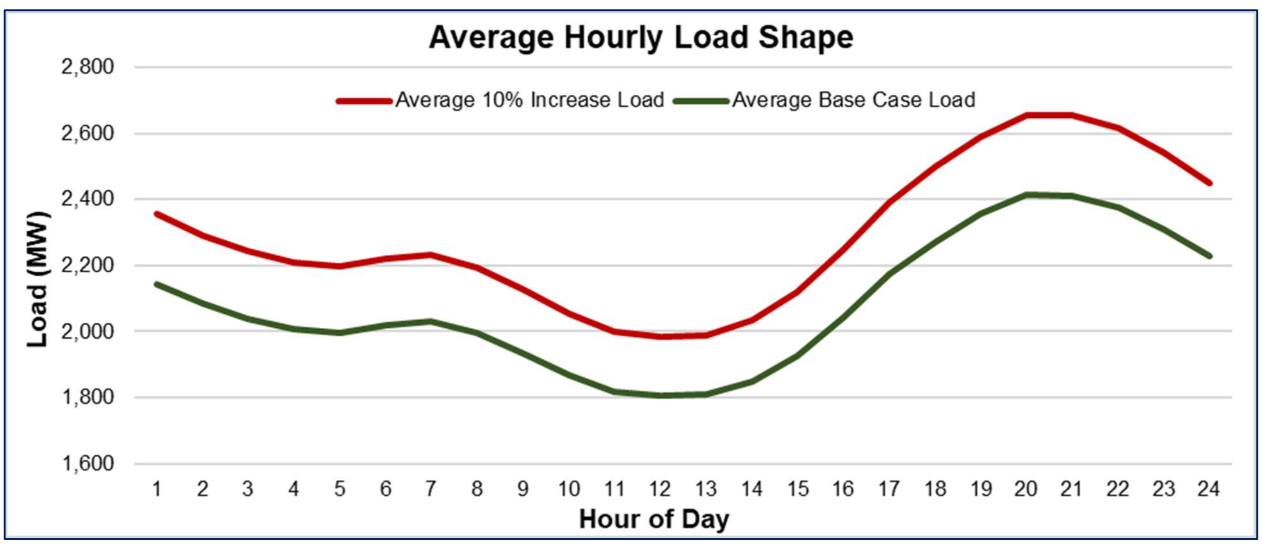
NEPR-MI-2022-0002

Figure A-41: Load Increase (+10%) Heat Map

Hour of Day	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Average by Hour
1	466	483	487	246	290	564	904	782	846	1,077	905	640	**641**
2	522	553	530	309	297	640	987	816	912	1,164	1,005	728	**705**
3	548	628	560	344	299	699	1,052	852	965	1,230	1,089	785	**754**
4	566	672	582	375	312	738	1,099	881	1,001	1,278	1,134	833	**789**
5	575	696	590	387	314	747	1,101	884	1,012	1,289	1,164	859	**802**
6	568	677	581	369	302	708	1,048	849	976	1,230	1,143	851	**775**
7	578	696	597	359	308	656	973	835	950	1,218	1,162	882	**768**
8	600	742	665	427	381	690	1,008	886	1,017	1,326	1,243	967	**829**
9	646	810	757	520	480	804	1,118	1,013	1,178	1,490	1,402	1,120	**945**
10	705	890	851	602	574	945	1,274	1,163	1,328	1,562	1,464	1,183	**1,045**
11	756	961	900	642	649	1,046	1,383	1,255	1,435	1,697	1,603	1,333	**1,138**
12	781	989	920	642	666	1,083	1,447	1,321	1,476	1,736	1,662	1,392	**1,176**
13	788	999	914	635	650	1,087	1,481	1,366	1,507	1,732	1,644	1,350	**1,179**
14	760	952	861	570	611	1,048	1,451	1,343	1,480	1,688	1,535	1,274	**1,131**
15	706	852	744	447	536	928	1,370	1,267	1,382	1,616	1,399	1,186	**1,036**
16	629	706	585	288	441	740	1,188	1,155	1,213	1,385	1,191	1,007	**877**
17	542	518	452	133	280	513	953	1,013	979	1,147	959	815	**692**
18	462	372	343	35	173	377	770	843	766	980	786	632	**545**
19	389	270	251	-36	92	245	624	708	645	844	662	467	**430**
20	302	172	196	-59	83	229	557	632	549	723	545	355	**357**
21	272	146	197	-52	100	251	577	648	548	736	535	317	**356**
22	296	186	233	-11	126	292	622	669	584	780	572	352	**392**
23	341	256	308	72	184	372	700	704	660	832	638	416	**457**
24	396	364	399	167	238	471	803	742	749	955	769	510	**547**
Average by Month	**550**	**608**	**563**	**309**	**349**	**661**	**1,020**	**943**	**1,007**	**1,238**	**1,092**	**844**	

With a 10% increase in hourly load, the average system load rises across all hours of the day, as illustrated in Figure A-41. The graph shows that the average peak-hour load increases from approximately 2,400 MW in the Base Case to around 2,600 MW in the 10% load increase scenario.

Figure A-42: Average Hourly Load Shape Comparison



NEPR-MI-2022-0002

Load Decrease (-10%) Sensitivity:

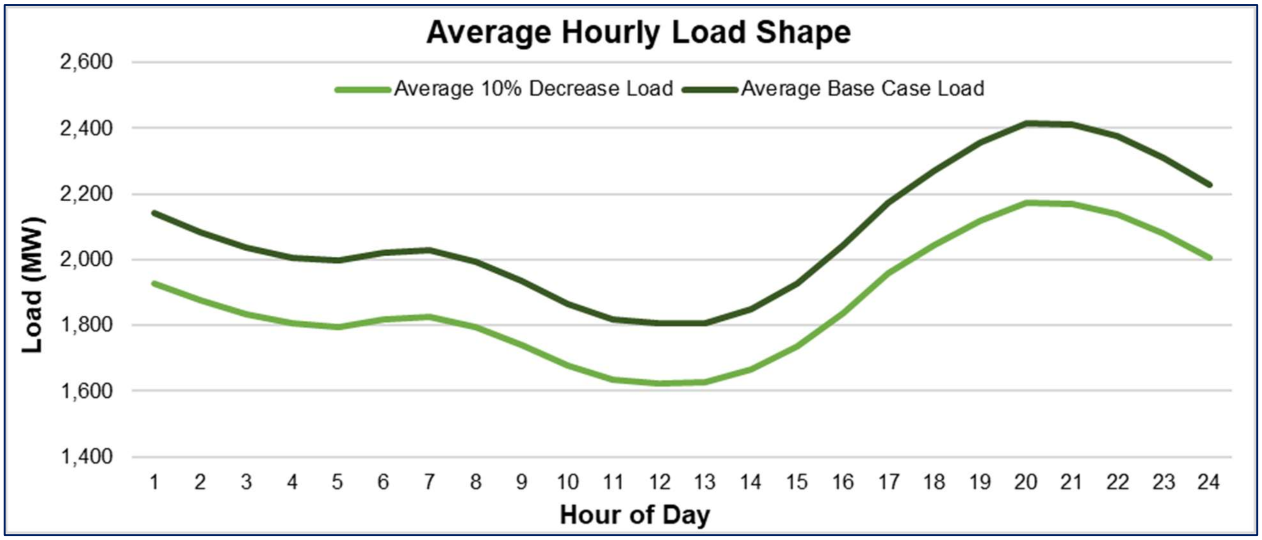
This sensitivity analysis examines the impact of a 10% reduction in hourly load throughout FY2026, aiming to assess potential improvements in resource adequacy if actual demand falls below forecasts, for example, due to lower temperatures. Unlike the load increase scenario, this case shows a notable improvement in average reserve levels across all hours and months. As illustrated in Figure A-43, October and November still exhibit the lowest reserve levels, primarily due to planned outages at several baseload units, including San Juan CC 5, AES 1, EcoEléctrica CT1, and Costa Sur 6.

Figure A-43: Load Decrease (-10%) Heat Map

Hour of Day	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Average by Hour
1	918	952	968	693	724	943	1,275	1,193	1,235	1,473	1,349	1,136	**1,072**
2	968	1,010	1,003	744	731	1,005	1,342	1,222	1,289	1,543	1,432	1,209	**1,125**
3	990	1,071	1,027	774	732	1,054	1,396	1,250	1,333	1,596	1,501	1,256	**1,165**
4	1,004	1,107	1,046	799	743	1,087	1,435	1,275	1,362	1,635	1,537	1,295	**1,194**
5	1,011	1,127	1,052	808	745	1,094	1,437	1,278	1,371	1,644	1,562	1,316	**1,204**
6	1,005	1,113	1,043	794	736	1,062	1,393	1,249	1,342	1,596	1,545	1,309	**1,182**
7	1,014	1,128	1,057	786	741	1,020	1,333	1,238	1,321	1,588	1,563	1,337	**1,177**
8	1,035	1,169	1,117	844	803	1,049	1,363	1,280	1,379	1,685	1,637	1,417	**1,232**
9	1,078	1,231	1,199	926	889	1,147	1,461	1,391	1,522	1,834	1,783	1,559	**1,335**
10	1,134	1,302	1,283	998	971	1,267	1,599	1,523	1,654	1,892	1,831	1,609	**1,422**
11	1,180	1,366	1,328	1,034	1,036	1,354	1,696	1,604	1,746	2,012	1,955	1,741	**1,504**
12	1,203	1,394	1,347	1,037	1,051	1,387	1,753	1,663	1,784	2,049	2,008	1,793	**1,539**
13	1,210	1,404	1,344	1,032	1,038	1,392	1,784	1,703	1,813	2,048	1,993	1,757	**1,543**
14	1,187	1,365	1,301	977	1,004	1,360	1,757	1,684	1,791	2,014	1,905	1,695	**1,503**
15	1,140	1,282	1,200	873	940	1,261	1,687	1,618	1,707	1,961	1,800	1,631	**1,425**
16	1,073	1,158	1,064	738	859	1,102	1,531	1,523	1,564	1,760	1,616	1,467	**1,288**
17	996	998	948	604	723	911	1,329	1,400	1,362	1,553	1,415	1,298	**1,128**
18	925	869	852	517	631	795	1,170	1,253	1,178	1,406	1,263	1,137	**999**
19	859	777	770	451	564	685	1,045	1,138	1,074	1,288	1,154	993	**900**
20	783	691	723	431	556	671	989	1,074	994	1,188	1,056	898	**838**
21	757	668	725	439	570	688	1,005	1,086	992	1,199	1,048	867	**837**
22	778	704	757	479	591	721	1,043	1,103	1,020	1,233	1,080	898	**867**
23	817	765	822	551	638	786	1,107	1,131	1,083	1,272	1,129	949	**921**
24	862	854	896	630	682	867	1,191	1,162	1,155	1,374	1,238	1,031	**995**
Average by Month	**997**	**1,063**	**1,036**	**748**	**779**	**1,030**	**1,380**	**1,335**	**1,378**	**1,618**	**1,517**	**1,316**	

With a 10% reduction in hourly load, the average system load decreases across all hours of the day, as shown in Figure A-44. The graph indicates that the average peak-hour load drops from approximately 2,400 MW in the Base Case to around 2,200 MW in the 10% load reduction scenario.

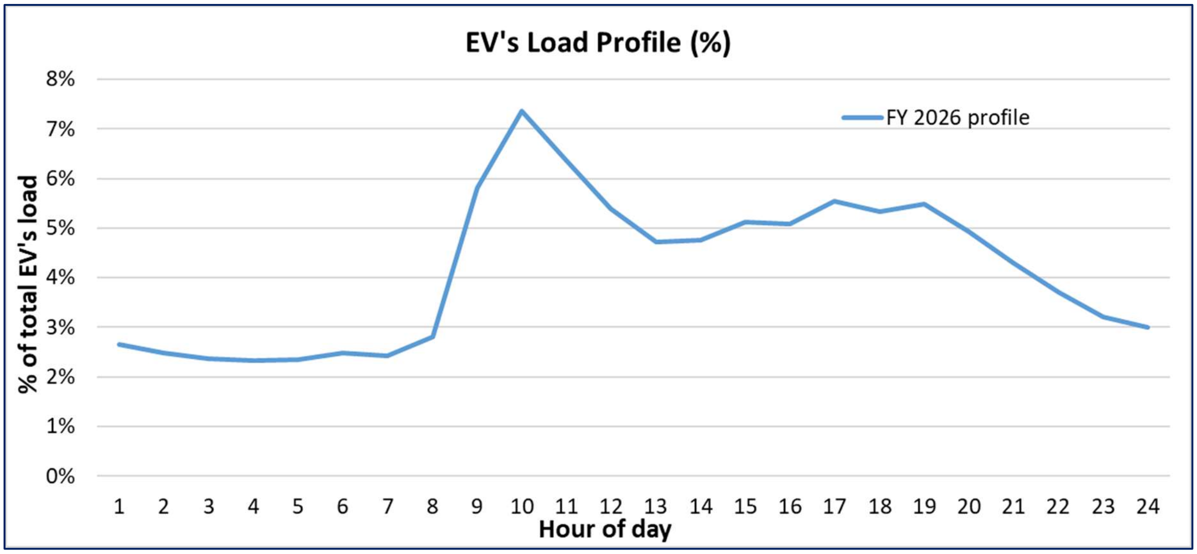
Figure A-44: Average Hourly Load Shape Comparison



Addition of Electric Vehicle (EV) Load Sensitivity:

One of the most important phenomena facing regional electricity grids worldwide is the growing adoption of electric vehicles (EVs) and the corresponding implications of EV charging requirements on electricity demand growth, resource adequacy and grid infrastructure expansion needs. To assess this issue for Puerto Rico, a resource adequacy sensitivity analysis was undertaken by increasing assumed electricity demands by amounts corresponding to estimated electricity consumption needs to support the addition of electric vehicles to the Puerto Rico automotive fleet. Figure A-45 shows the assumed EV hourly load profile for FY2026.

Figure A-45: Electric Vehicles (EV) Hourly Load Profile for FY2026



NEPR-MI-2022-0002

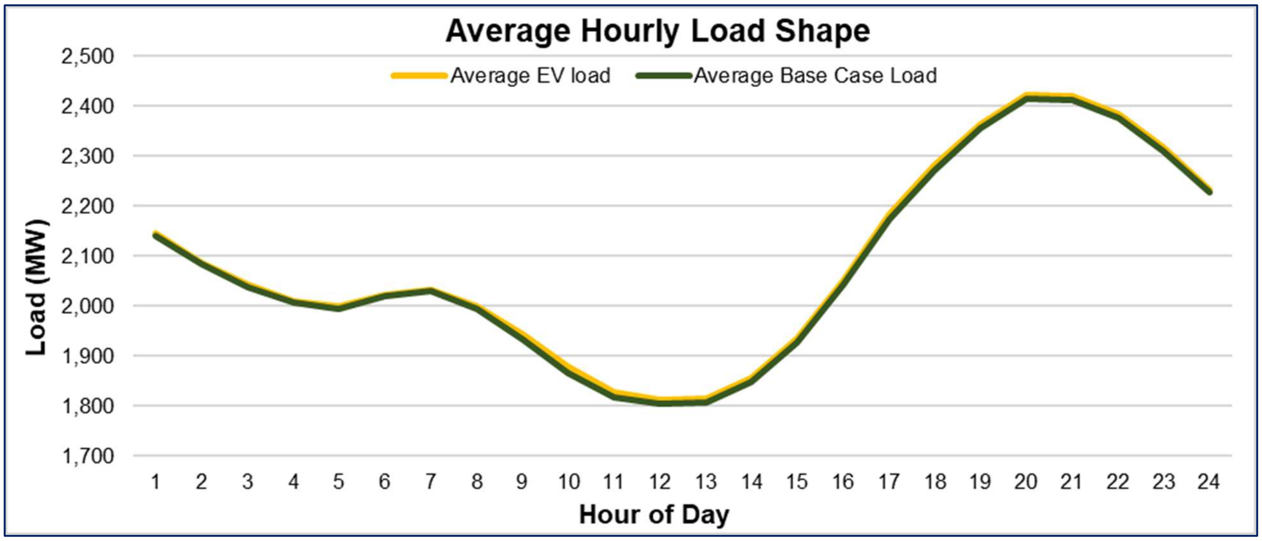
This sensitivity evaluates the impact of adding approximately 60 GWh of electricity consumption during FY2026, attributed to electric vehicle (EV) charging. This total translates to about 5 GWh per month, roughly 167 MWh per day, or approximately 7 MWh per hour. At the system level, this represents a relatively minor increase in demand, suggesting that EV charging would not significantly affect overall resource adequacy. As shown in Figure A-46, the average hourly reserve levels under the EV sensitivity scenario are comparable to those in the Base Case presented in Section 3.1.2.

Figure A-46: Addition of Electric Vehicle Load Heat Map

Hour of Day	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Average by Hour
1	685	715	725	465	500	749	1,086	980	1,034	1,269	1,124	887	**851**
2	739	780	764	523	507	818	1,160	1,012	1,094	1,348	1,216	969	**911**
3	763	848	792	556	510	872	1,221	1,044	1,142	1,408	1,293	1,020	**956**
4	778	888	812	585	521	908	1,263	1,071	1,174	1,452	1,332	1,064	**987**
5	786	911	820	596	523	916	1,266	1,074	1,184	1,462	1,360	1,087	**999**
6	780	894	811	579	512	880	1,217	1,042	1,151	1,408	1,341	1,079	**974**
7	790	911	826	571	518	833	1,149	1,030	1,127	1,397	1,359	1,108	**968**
8	811	954	889	634	584	869	1,181	1,076	1,189	1,499	1,437	1,190	**1,026**
9	852	1,013	972	716	672	986	1,280	1,191	1,336	1,650	1,585	1,332	**1,132**
10	907	1,085	1,058	789	758	1,129	1,424	1,329	1,473	1,633	1,559	1,310	**1,205**
11	956	1,154	1,106	831	829	1,238	1,529	1,417	1,572	1,741	1,671	1,429	**1,289**
12	982	1,183	1,127	833	846	1,281	1,591	1,482	1,612	1,780	1,726	1,483	**1,327**
13	990	1,193	1,124	829	832	1,287	1,625	1,525	1,643	1,778	1,711	1,446	**1,332**
14	965	1,151	1,076	769	796	1,249	1,596	1,505	1,618	1,740	1,613	1,378	**1,288**
15	914	1,059	967	654	727	1,129	1,520	1,433	1,527	1,778	1,592	1,399	**1,225**
16	842	925	819	506	638	943	1,351	1,329	1,375	1,562	1,395	1,228	**1,076**
17	759	750	694	361	489	717	1,132	1,196	1,156	1,339	1,178	1,048	**902**
18	683	612	591	268	391	578	962	1,037	959	1,183	1,015	876	**763**
19	613	514	503	198	316	455	826	913	847	1,056	898	722	**655**
20	533	423	453	177	308	441	765	844	761	946	793	620	**589**
21	505	398	454	185	326	461	784	859	761	959	785	587	**589**
22	528	437	490	228	350	499	827	879	793	999	820	620	**623**
23	571	504	561	306	403	572	899	912	864	1,045	878	679	**683**
24	622	604	645	394	453	663	992	946	945	1,158	1,000	769	**766**
Average by Month	**765**	**829**	**795**	**523**	**555**	**853**	**1,194**	**1,130**	**1,181**	**1,400**	**1,278**	**1,055**	

The load shape in the EV sensitivity scenario is nearly identical to that of the Base Case, with differences so minimal they are not visually distinguishable, as shown in Figure A-47.

Figure A-47: Average Hourly Load Shape Comparison



A.3 Force Majeure Scenario

As shown by Hurricane Maria in 2017, the January 2020 6.4 magnitude earthquake, and Hurricane Fiona in 2022, natural disasters can be devastating to Puerto Rico's electricity system. In addition to damaging transmission and distribution infrastructure, such catastrophes can also knock out power plants for months. Given that the Puerto Rico electricity system is already resource-deficient in the Base Case, this section describing a "Force Majeure" Scenario aims to quantify how much more resource-deficient the system could become if it experienced a large disaster during FY2026.

Resource adequacy under the Force Majeure Scenario was modeled by increasing assumed forced outage rates at Puerto Rico's thermal power plant fleet and the System Load relative to the assumptions used in the Base Case. This modeling approach was developed from experience gained in the wake of Hurricane Fiona. Due to the damage caused by the hurricane and the duration required to restore the plants to operational status, thermal generation forced outage rates were 50% above historical levels six months after the hurricane. Reflecting this experience, the forced outage rate assumptions for all thermal generation units in the Force Majeure Scenario were increased by 50% from Base Case levels for six months after a disaster (assumed to occur on September 15, 2025). The System Load was adjusted to be 0 MW at the event day and gradually increased until reaching 90% of the demanded load in 2 weeks after the event and 100% of the System Load a month after the impact of a force majeure scenario.

Table A-4 shows that the resulting estimated LOLE for this Force Majeure Scenario has an increase of 94% and an estimated LOLH increase of 145% compared to the Base Case. In summary, resource adequacy metrics in Puerto Rico would worsen by approximately a factor of two from Base Case levels if a major disaster were to occur.

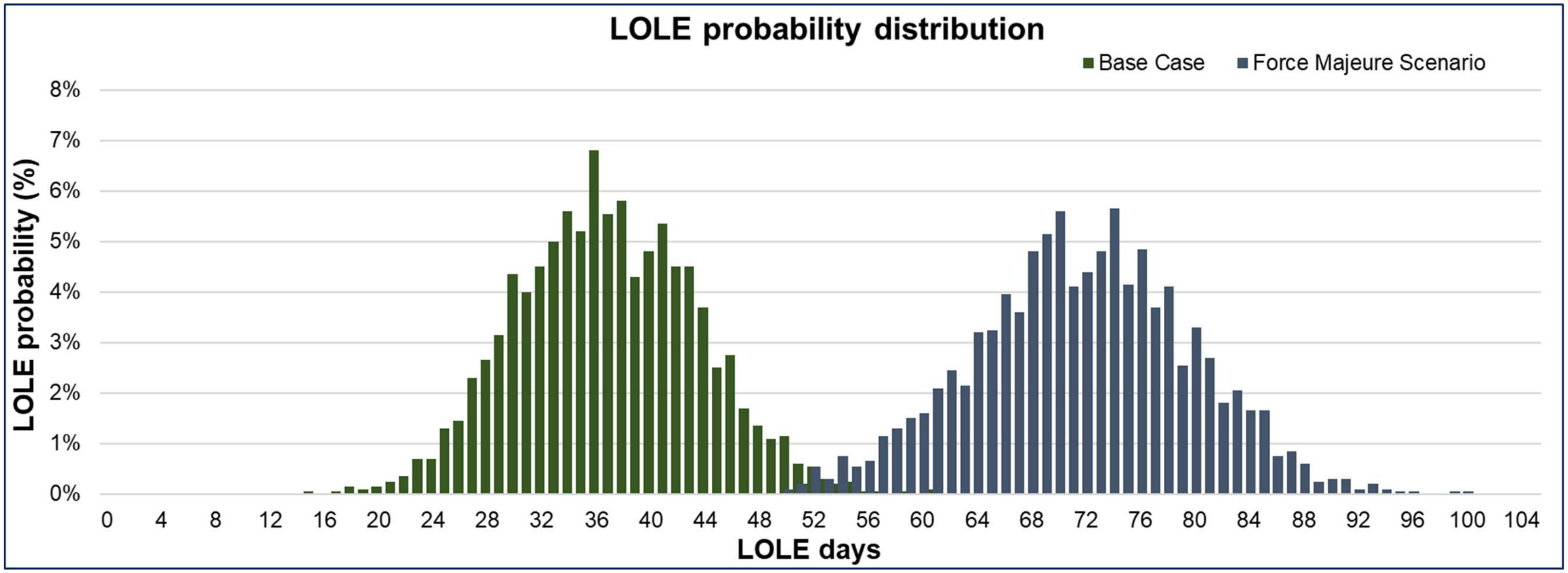
Table A-4: Calculated Resource Adequacy Measures Associated with a Force Majeure Scenario

Sensitivity Analysis	Loss of Load Expectation (LOLE)	Loss of Load Hours (LOLH)
Base Case	36.9 Days / Year	196.3 Hours / Year
Force Majeure Scenario	71.7 Days / Year	480.4 Hours / Year

NEPR-MI-2022-0002

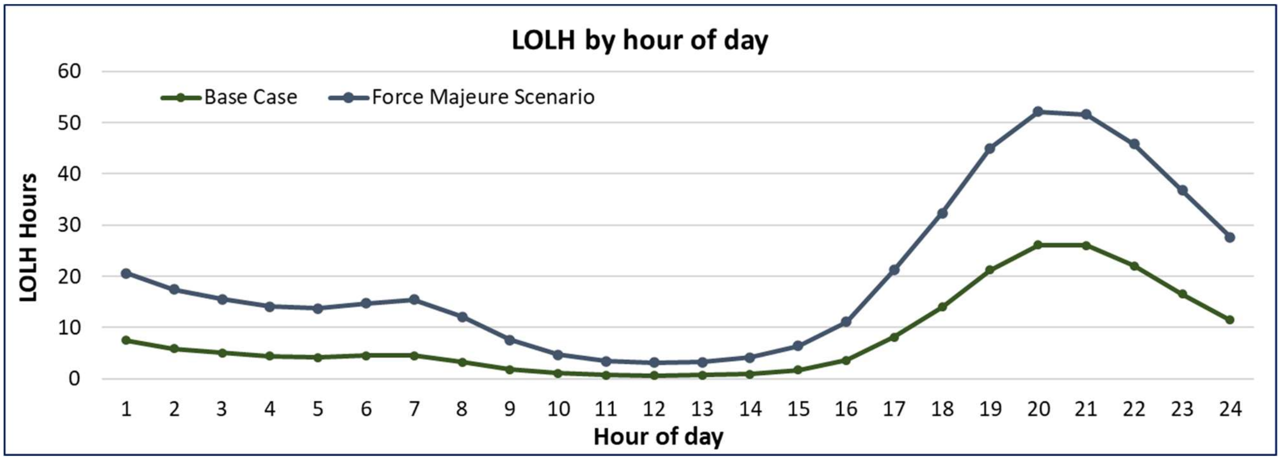
Figure A-48 shows how the probability distribution of outcomes for LOLE significantly worsens relative to the Base Case if Puerto Rico experiences a force majeure scenario in FY2026.

Figure A-48: Comparison of LOLE Probability Distributions Associated with Unavailability of Resources



Meanwhile, Figure A-49 indicates how much LOLH increases relative to the Base Case for this sensitivity. The impact can be appreciated at all hours during the day with almost duplicating the amount of LOLH at peak load hours.

Figure A-49: Comparison of LOLH Associated with Unavailability of Resources



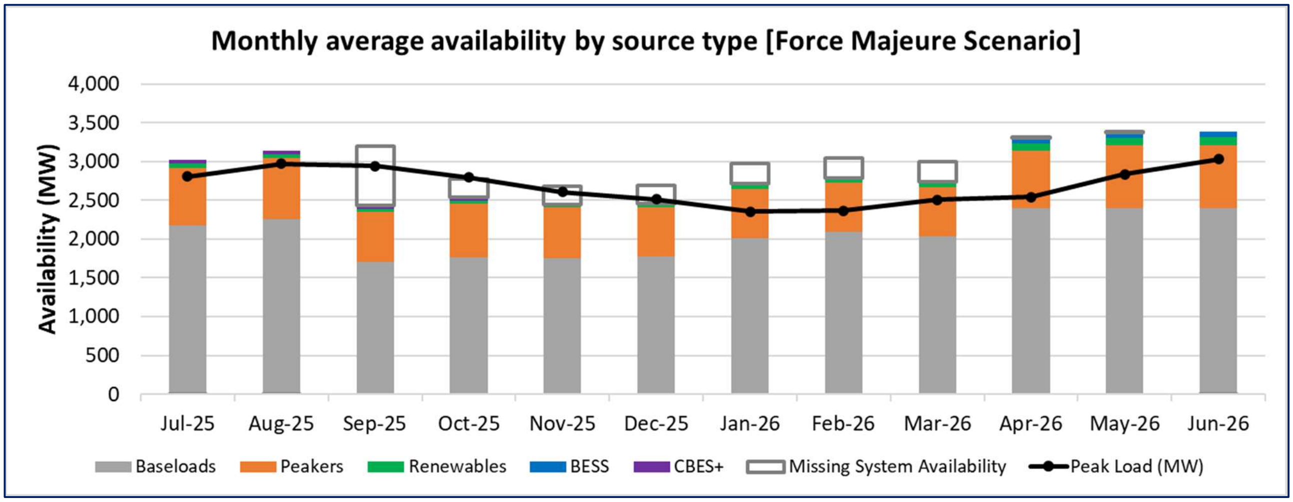
As shown in Figure A-50, reserve capacity levels during peak demand hours in the Force Majeure Scenario fall well below 650 MW in most months—except for April and May 2026—and drop below 100 MW during peak hours in October and November, indicating a very high risk of load-shedding events.

Figure A-50: Force Majeure Scenario Heat Map

Hour of Day	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Average by Hour
1	671	694	558	316	252	504	810	703	763	1,247	1,112	872	**709**
2	724	759	585	370	259	574	884	736	823	1,327	1,203	952	**766**
3	749	827	606	402	261	628	944	767	872	1,388	1,279	1,004	**811**
4	764	866	622	429	272	663	987	794	904	1,433	1,319	1,047	**842**
5	772	889	628	439	275	672	989	799	914	1,443	1,346	1,071	**853**
6	765	873	619	423	264	636	940	767	881	1,389	1,327	1,063	**829**
7	774	890	630	414	270	589	872	753	858	1,380	1,344	1,092	**822**
8	796	933	680	474	337	625	905	800	920	1,483	1,423	1,174	**879**
9	842	998	747	560	429	748	1,009	920	1,072	1,639	1,575	1,324	**989**
10	900	1,073	817	634	518	893	1,157	1,060	1,213	1,624	1,552	1,305	**1,062**
11	947	1,141	854	672	587	1,000	1,261	1,146	1,310	1,732	1,661	1,421	**1,144**
12	971	1,169	870	674	602	1,042	1,321	1,208	1,349	1,770	1,716	1,473	**1,180**
13	978	1,177	867	669	588	1,047	1,354	1,248	1,380	1,768	1,700	1,434	**1,184**
14	953	1,134	831	611	551	1,008	1,327	1,227	1,355	1,730	1,602	1,367	**1,141**
15	904	1,043	750	503	482	890	1,251	1,157	1,264	1,768	1,581	1,388	**1,082**
16	830	908	642	363	394	704	1,082	1,054	1,112	1,552	1,384	1,218	**937**
17	748	734	547	225	245	479	863	922	893	1,330	1,168	1,037	**766**
18	672	595	471	138	145	340	691	763	695	1,173	1,006	867	**630**
19	603	498	406	71	71	217	555	639	582	1,046	891	713	**524**
20	521	406	369	49	64	202	493	569	494	935	783	611	**458**
21	493	382	367	56	79	221	511	584	492	949	775	576	**457**
22	516	419	390	95	102	258	552	604	523	988	810	609	**489**
23	558	486	438	167	154	331	623	635	593	1,033	867	666	**546**
24	609	584	499	251	203	420	716	669	674	1,146	989	756	**626**
Average by Month	**752**	**812**	**616**	**375**	**309**	**612**	**921**	**855**	**914**	**1,386**	**1,267**	**1,043**	

Reserve levels are significantly impacted during the Force Majeure Scenario, particularly in the months from September 2025 through March 2026. As shown in Figure A-51, September is the most affected month, with an estimated shortfall in availability of approximately 760 MW, based on the assumptions outlined at the beginning of this section. Additionally, six months after the assumed onset of the force majeure event in September 2025, system availability remains reduced by about 250 MW.

Figure A-51: Monthly Average Availability of a Force Majeure Scenario



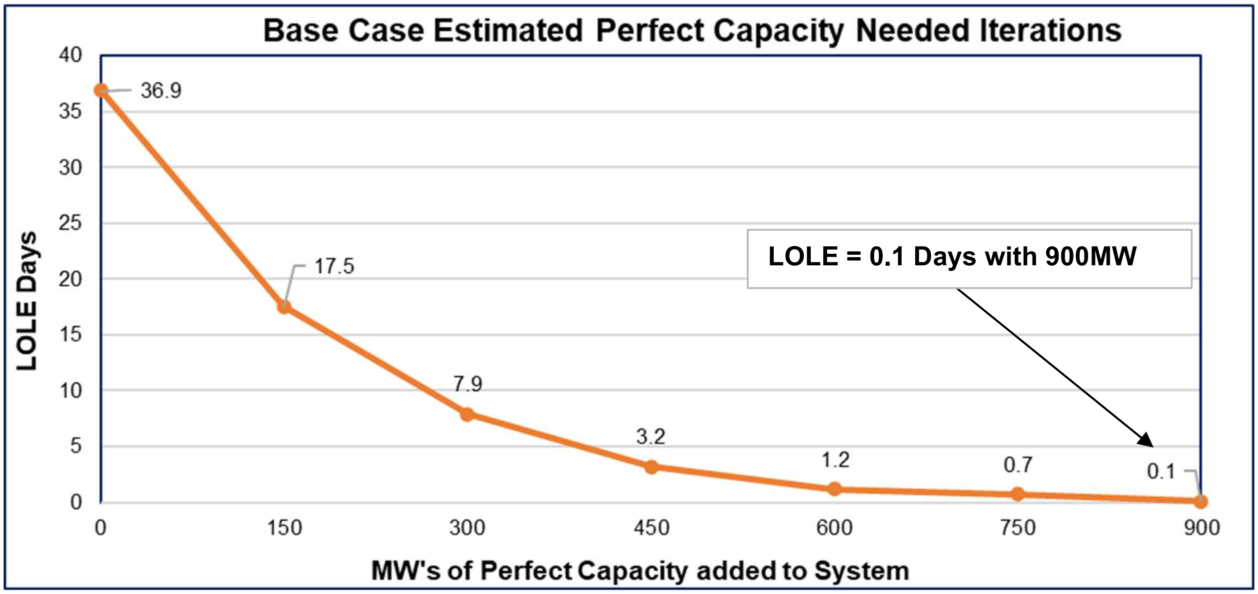
A.4 900 MW of Perfect Capacity

The "Perfect Capacity" methodology means "generation always available: a perfect generator" and estimates how many MWs are needed to reach the benchmark of 0.1 LOLE days. For Puerto Rico, for FY2026, the estimated Perfect Capacity resulted to be **900 MW** under Base Case assumptions. This result was accomplished by adding various amounts of perfect capacity in the resource modeling analyses so that the resulting LOLE would equal 0.10 days/year. Note that the analyses presented herein do not evaluate the types of incremental supply resources to be installed, estimate costs of new resources, or address policy impacts associated with resource expansion. These matters are considered in the Integrated Resource Plan (IRP) recently submitted by LUMA.

Figure A-52 shows the iterative process for the calculation of the amount of perfect capacity needed to reach 0.10 LOLE days/year. Perfect capacity additions were increased in 150 MW increments between iterations, until reached 900 MW where LOLE result is 0.1 days.

NEPR-MI-2022-0002

Figure A-52: Loss of Load Expectation with Incremental Amounts of Perfect Capacity



Given that no generation technology can operate as a perfect generator, the actual amount of new capacity additions required for the Puerto Rico electricity system to meet a 0.1 days/year LOLE target would be somewhat higher than the 900 MW identified above. Additionally, this 900 MW of perfect capacity resulted with the actual electric system status, any change on available resources (decommissions or additions) will affect the amount of perfect capacity estimated to reach the industry standard of 0.1 LOLE days/year.

Appendix B: Supply Resource Modeling Assumptions

This appendix documents the key assumptions used in the resource adequacy modeling for thermal power plants, renewable energy facilities, and battery energy storage systems. All assumptions presented in this report are based on data and information available prior to July 2025. Any updates or changes made after that date are not reflected in this analysis.

B.1 Thermal Generation Inputs

Given the high degree of reliance on thermal generation in the Puerto Rico electricity system and the low availability of the thermal power plant fleet, assumptions about thermal generation are vital to this resource adequacy analysis. The following sets of assumptions are especially critical.

Available Capacity

The available capacity of a thermal generator (nameplate capacity minus any derates) defines the maximum reliable 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). To develop assumptions for the available capacity for each power plant unit, LUMA reviewed the last five years of generation data for each unit and then calculated the 95th percentile of hourly generation production that each unit achieved for each of the past five years. The rationale for this is that the system operator would typically request all baseload 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. Table B-1 below present, for each thermal power plant unit, the calculation of available capacity incorporated in the resource adequacy analysis as well as the values used for the last 3 fiscal years resource adequacy studies.

Table B-1: Maximum Dependable Capacities used in Resource Adequacy Studies Through the last Three Fiscal Years

Unit	FY2024 Available Capacity Input (MW)	FY2025 Available Capacity Input (MW)	FY2026 Available Capacity Input (MW)
AES 1	227	227	227
AES 2	227	227	227
Aguirre 1	350	300	300
Aguirre 2	330	350	340
Costa Sur 5	350	250	330

NEPR-MI-2022-0002

Unit	FY2024 Available Capacity Input (MW)	FY2025 Available Capacity Input (MW)	FY2026 Available Capacity Input (MW)
Costa Sur 6	350	350	350
EcoElectrica CT1	172.5	172.5	172.5
EcoElectrica CT2	172.5	172.5	172.5
EcoElectrica Steam	200	200	200
Palo Seco 3	190	160	170
Palo Seco 4	190	160	180
San Juan 5 CT	150	155	155
San Juan 5 Steam	50	55	55
San Juan 6 CT	150	155	155
San Juan 6 Steam	50	55	55
San Juan 7	70	70	90
San Juan 9	90	90	90
Aguirre 1 CC	220 MW (2 x 110 MW)	100	150
Aguirre 2 CC	100 MW (2 x 50 MW)	100	130
Cambalache 2	75	75	78
Cambalache 3	75	75	78
Mayagüez 1	50	47.5	50
Mayagüez 2	50	47.5	50
Mayagüez 3	25	47.5	25

NEPR-MI-2022-0002

Unit	FY2024 Available Capacity Input (MW)	FY2025 Available Capacity Input (MW)	FY2026 Available Capacity Input (MW)
Mayagüez 4	50	47.5	25
Peaker gas turbines (F5)	147 MW (7 x 21 MW)	147 MW (7 x 21 MW)	147 MW (7 x 21 MW)
Palo Seco MP	81 MW (3 x 27 MW)	81 MW (3 x 27 MW)	81 MW (3 x 27 MW)
Palo Seco TM	-	150 MW (2 x 25 MW) + (2 x 20 MW) + (3 x 30 MW)	90 MW (2 x 25 MW) + (2 x 20 MW)
San Juan TM	-	200 MW (8 x 25 MW)	250 MW (10 x 25 MW)
Total	4192	4347	4423

Overall, the total available capacity has been slightly increasing over the past three years, resulting in similar LOLE results in FY2025 and FY2026. This is because LOLE events are also affected by planned outages, forced outages and the expected hourly demand.

Outage Schedule

This input defines when thermal generators are expected to be out on a planned maintenance outage. Figure B-1 and Figure B-2 below show when the thermal units are assumed to be out of operation during FY2026, either due to planned regular maintenance or because the unit is in a forced outage. This maintenance schedule was sent by LUMA operations on July 31, 2025.

Figure B-1: Outage Schedule for Thermal Units in Base Case

Forced Outage
Planned Outage

Offline = 1			Jul-25					Aug-25				Sep-25				Oct-25				Nov-25					Dec-25					Jan-26				Feb-26			Mar-26					Apr-26					May-26				Jun-26	
AES 1	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AES 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Aguirre 1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Aguirre 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Costa Sur 5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Costa Sur 6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EcoElectrica CT1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EcoElectrica CT2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EcoElectrica Steam	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Palo Seco 3	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Palo Seco 4	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
San Juan 5 CT	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
San Juan 5 Steam	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
San Juan 6 CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
San Juan 6 Steam	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
San Juan 7	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
San Juan 9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Aguirre 1 CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Aguirre 2 CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cambalache 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cambalache 3	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0
Mayagüez 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mayagüez 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mayagüez 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Figure B-2: Outage Schedule for Thermal Units in Base Case

Forced Outage
Planned Outage

Offline = 1			Jul-25					Aug-25				Sep-25				Oct-25				Nov-25					Dec-25					Jan-26				Feb-26			Mar-26					Apr-26					May-26				Jun-26	
Mayagüez 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Palo Seco MP 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Palo Seco MP 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Palo Seco MP 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas Turbine 1 (F5)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas Turbine 2 (F5)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas Turbine 3 (F5)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas Turbine 4 (F5)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas Turbine 5 (F5)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas Turbine 6 (F5)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas Turbine 7 (F5)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Palo Seco TM 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Palo Seco TM 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Palo Seco TM 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Palo Seco TM 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
San Juan TM 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
San Juan TM 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
San Juan TM 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
San Juan TM 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
San Juan TM 5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
San Juan TM 6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
San Juan TM 7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
San Juan TM 8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
San Juan TM 9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
San Juan TM 10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Note that Aguirre 1 is offline for the entire study period (FY2026) due to a generator failure that occurred in February 2025, with an estimated time to return (ETR) of June 30, 2026. Additionally, Palo Seco 3 is assumed to remain offline throughout FY2026. For modeling purposes, this assumption was made because Palo Seco 3 is a relatively small unit, and one of the larger baseload plants, Aguirre 1, is already out of service for the full forecast year. This approach helps capture the generation capacity shortfall that can result from an increased number of forced outages across the fleet when major baseload units are unavailable and the remaining units are required to operate more intensively. For context, there were periods in 2024 when two or more baseload units were simultaneously offline.

Forced Outage Rates

The forced outage rate represents the percentage of hours in a year during which a power plant is unavailable due to being inoperative. While the EcoEléctrica power plant maintains a relatively low forced outage rate of approximately 3%, the legacy PREPA generation units, now operated by Genera, have historically exhibited significantly higher forced outage rates compared to industry standards. This is largely due to the age of these units and the suboptimal maintenance they have received over time. As a result, forced outage rate assumptions for Puerto Rico's legacy generation fleet play a critical role in resource adequacy modeling.

For this assessment, forced outage rate assumptions are based on historical performance data. Tables B-2 and B-3 summarize the forced outage rates for baseload and peaking units respectively, as used in the past three fiscal year resource adequacy studies, along with the rates applied in this report.

Table B-2: Baseloads Forced Outages Rates used in Resource Adequacy Studies Through the Years

Baseload Unit	FY2024 Forced Outage Rate Input (%)	FY2025 Forced Outage Rate Input (%)	FY2026 Forced Outage Rate Input (%)
AES 1	5%	5%	10%
AES 2	5%	10%	15%
Aguirre 1	20%	25%	30%
Aguirre 2	15%	15%	20%
Costa Sur 5	12%	20%	20%
Costa Sur 6	15%	15%	15%
EcoElectrica CT 1	2%	2%	3%
EcoElectrica CT 2	2%	2%	3%
EcoElectrica STG	2%	2%	3%
Palo Seco 3	12%	15%	15%
Palo Seco 4	18%	60%	25%

San Juan 5 CT	12%	15%	5%
San Juan 5 STG	12%	15%	10%
San Juan 6 CT	12%	15%	10%
San Juan 6 STG	12%	15%	20%
San Juan 7	30%	40%	45%
San Juan 9	8%	8%	5%
Total Weighted	**12%**	**17%**	**20%**

Note that the system's forced outage rate increased by 5% from FY2024 to FY2025, but remained relatively stable when comparing FY2025 to FY2026.

Table B-3: Peakers Forced Outage Rates used in Resource Adequacy Studies Through the Years

Peaker Unit	FY2024 Forced Outage Rate Input (%)	FY2025 Forced Outage Rate Input (%)	FY2026 Forced Outage Rate Input (%)
Aguirre CC 1	40%	50%	50%
Aguirre CC 2	40%	40%	60%
Cambalache 2	10%	10%	10%
Cambalache 3	10%	10%	15%
Mayaguez 1	30%	30%	30%
Mayaguez 2	30%	30%	30%
Mayaguez 3	30%	30%	30%
Mayaguez 4	30%	30%	30%
Daguao 1-1	40%	40%	40%

NEPR-MI-2022-0002

Peaker Unit	FY2024 Forced Outage Rate Input (%)	FY2025 Forced Outage Rate Input (%)	FY2026 Forced Outage Rate Input (%)
Daguao 1-2	40%	40%	40%
Jobos 1-2	40%	40%	40%
Yabucoa 1-2	40%	40%	40%
Palo Seco 1-1	40%	40%	40%
Palo Seco 1-2	40%	40%	40%
Palo Seco 2-1	40%	40%	40%
Palo Seco MP 1	9%	9%	40%
Palo Seco MP 2	9%	9%	40%
Palo Seco MP 3	9%	9%	40%
Palo Seco TM 1	-	3%	10%
Palo Seco TM 2	-	3%	10%
Palo Seco TM 3	-	3%	10%
Palo Seco TM 4	-	3%	20%
San Juan TM 1	-	3%	25%
San Juan TM 2	-	3%	15%
San Juan TM 3	-	3%	15%
San Juan TM 4	-	3%	30%
San Juan TM 5	-	3%	15%

NEPR-MI-2022-0002

Peaker Unit	FY2024 Forced Outage Rate Input (%)	FY2025 Forced Outage Rate Input (%)	FY2026 Forced Outage Rate Input (%)
San Juan TM 6	-	3%	15%
San Juan TM 7	-	3%	10%
San Juan TM 8	-	3%	15%
San Juan TM 9	-	3%	30%
San Juan TM 10	-	3%	15%
Total Weighted	**25%**	**28%**	**36%**

Note that the forced outage rate for peaking units has been steadily increasing over the past three years. Even with the addition of the TM generators in FY2025, their performance has not met expectations, contributing to the overall rise in the peakers' forced outage rate.

Forced Outage Duration

This input defines how long it takes a thermal power plant to come back online after a forced outage is simulated to occur. For this analysis, the forced outage duration for all thermal generation is set (by assumption) to 40 hours.

To test this assumption, a sensitivity analysis was performed by LUMA in Appendix 9 of its *FY2023 Puerto Rico Electrical System Resource Adequacy Analysis* report 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. For each of these five modeling runs, the modeled outage duration was applied for all generators. The results of this sensitivity analysis showed that, as forced outage durations increase, there was a slight decrease in LOLE but no discernible difference in LOLH – illustrating that when modeling forced outages, forced outage rates (which are based on historical generator performance and are a good indication of expected generator availability) are more critical than forced outage durations in resource adequacy evaluations.

B.2 Renewable Generation Inputs and Methodology

It is critical for resource adequacy analysis to properly capture the hourly capacity contributions from renewable power plants based on solar and wind energy, since the hourly contributions of variable generators are, by definition, uncertain. Overestimating the capacity contribution of variable generators will lead to overestimates of resource adequacy, which could cause decision-makers to think the electricity grid has more capability than it really does, thus leaving the system exposed to greater risk of capacity shortfalls in the event the variable generators are unable to generate as expected. Meanwhile, underestimating the capacity contribution of variable generators can make the electrical system appear less reliable than it really is, thus leading to overestimation of (and potentially overinvestment in) new resource requirements.

For this resource adequacy assessment, the following assumptions were made regarding electricity generation from wind and solar energy power plants in Puerto Rico.

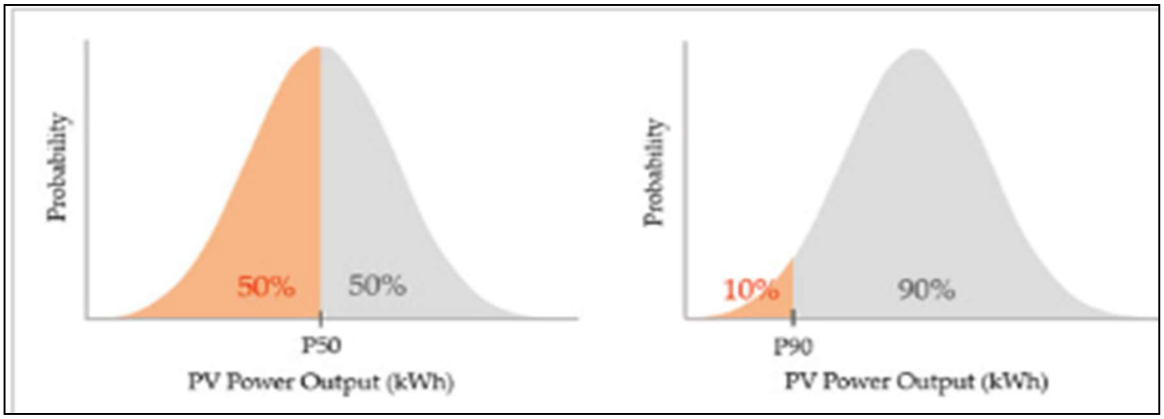
Existing Renewable Generation

Simulated generation from existing renewable power plants is based on historical operating data from 2019 through 2024 from each power plant. For this resource adequacy analysis, each power plant's historical 50th percentile production level (i.e., P50 production level) for each hour of the day was identified and used.

It is important to note that a P50 generation level is less conservative than a P90 level, which is the minimum output that can be expected at least 90% of the time during the hour of the day in question. Given the variability of the climate in Puerto Rico, it was decided to use an "average" (P50) since there can be as many sunny days as cloudy days.

Figure B-3 illustrates how P90 generation levels will always be somewhat lower than P50 generation levels.

Figure B-3: P50 and P90 PV Output Levels by Hour



Planned Renewable Generation

Several sensitivity analyses presented herein explored the impacts on resource adequacy of adding new renewable energy power projects. For planned renewable energy projects in sensitivity analyses, historical data is not available for developing P50 assumptions on electricity generation that can be anticipated in each hour. Instead, for such future renewable generation sources, forecasted hourly generation is computed based on the historical output of existing renewable resources in Puerto Rico. All forecasted hourly profiles are adjusted to a P50 probabilistic level for each hour of generation prior to performing the simulations. Then, the historical P50 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.

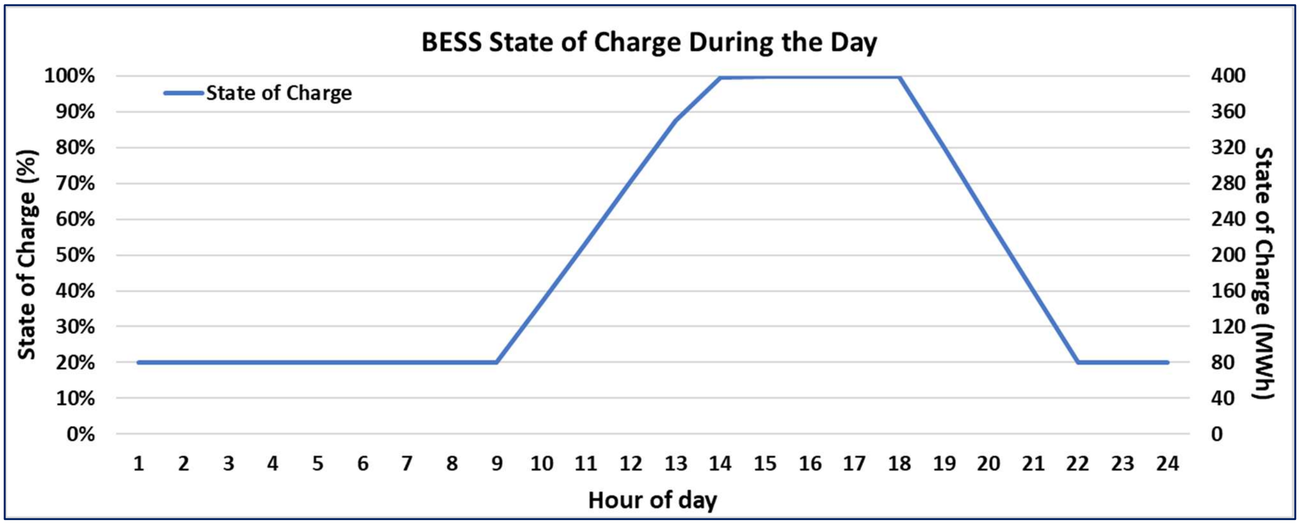
B.3 Energy Storage Inputs

There is no utility-scale energy storage currently installed in Puerto Rico. Energy storage capacity is currently limited to behind-the-meter (BTM) customer-sited energy storage, which are being used for the demand response program: CBES+. A commercial BESS project (CFE Salinas BESS) is assumed in the Base Case resource adequacy assessment since its expected Commercial Operating Date (COD) is by end of March 2026, inside the resource adequacy study period. Additionally, since energy storage represents an important opportunity to improve resource adequacy in Puerto Rico, several sensitivity analyses were undertaken that include the assumption of additional energy storage resources being added, in order to investigate impacts of energy storage on Puerto Rico's resource adequacy.

In sensitivity analyses that include energy storage resources, all energy storage resources are assumed to be based on batteries – hence the term battery energy storage systems (BESS) used throughout this report. All BESS resources are modeled as having an 85% round-trip efficiency (i.e., 15% losses between energy consumed from the grid during charging and energy injected into the grid during discharging), by assumption.

Energy storage resources are modeled such that the normal (non-emergency) discharge time is set to start in the evening, coinciding with peak load. All BESS systems were assumed to be configured with 4-hour duration. The 4 hours of discharge were assumed to occur during peak hours when System Load is consistently observed to be highest (between 6:00 p.m. to 10:00 p.m.). When discharging begins, energy storage is modeled to inject over the succeeding four hours a total of 80% of the total rated capacity (making the operating range from 20% to 100% of their capacity level). The usage of energy storage is assumed to be limited between 20% and 100% because cycling of BESS resources outside of this range (i.e., discharging all the way to zero) has been found to significantly worsen battery health and shorten lifespan. Also, these energy storage resources are modeled to have a 4-hour charging range, as long as the reserve levels are at 300 MW as minimum. The charging time was set between 10:00 a.m. to 2:00 p.m., since in those hours is where there are more reserve levels available during those hours to charge the batteries (as shown in section 3.2.2). Figure B-4 illustrates the state of charge of the batteries during the day (taking as example a 100 MW, 4-hr BESS project).

Figure B-4: BESS State of Charge During the Day



If an emergency event occurs (i.e., a time when load exceeds available capacity), energy storage resources are modeled such that they inject stored energy up to the amount needed to meet the system generation shortfall -- or if the generation shortfall is greater that stored energy volumes, to minimize the magnitude of the shortfall. During emergency events, energy storage resources are modeled to inject stored energy as described above, regardless of the time of day or how much energy is stored at that time. Once the amount of stored energy is depleted (i.e., state-of-charge falls to 20% of rated capacity), energy storage resources are unable to inject additional energy, and must wait until non-emergency hours for charging to resume.

Appendix C: Resource Adequacy Methodologies

Resource adequacy is the discipline in electric utility planning that assesses the extent to which generation capacity on an electricity system will not be sufficient to serve aggregate electricity demands from all customers on the system under all conceivable conditions over the planning horizon. Resource adequacy informs utility planners and regulators on whether additions to system generating capacity are necessary – and if so, how much new generation should be added.

Historically, this judgment has often been made by considering the region's generation planning reserve margin (PRM). The PRM is defined as the amount (in percent) by which the total system generation capacity exceeds peak electricity demand. A region's PRM thus provides a simple measure of the amount of operational capacity relative to peak demand. However, there is no standard for what an appropriate PRM should be for any given electricity system. While higher PRMs typically equate to a lower risk that load will not be served during a given timeframe, higher PRMs also imply higher costs to society, as it necessarily requires more generation capacity to be in place and operational. In general, PRMs have historically been set by utility planners based on decades of experience in managing a region's electricity system, considering the unique characteristics of the system including its fleet of power plants, robustness of transmission network and interconnections to neighboring utilities, electricity demand patterns, and adverse weather conditions the region will face. As a result, PRMs vary from utility to utility, though they have tended to be in the range of 10-25%.

Because the electricity industry worldwide is relying much more heavily on renewable energy sources (solar and wind) that are intermittently available, historical "rules-of-thumb" about resource adequacy based on achieving a fixed level of PRM do not reflect the likelihood that most installed capacity – although operationally functional – will be able to deliver electricity when requested because of lack of sun or wind.

To improve upon resource planning approaches that were based on PRM, modern resource adequacy assessments are rooted in a probabilistic approach to quantify the risk that electricity supply will be unable to fully serve System Load every hour of the year. Fundamentally, resource adequacy assessments involve the development of quantitative estimates of the probability that generation supply will be insufficient to serve System Load. Note that an indicated resource deficiency does not mean the entire electricity system will go down, blacking out service to all customers. Instead, it signifies that there is not enough generation to serve System Load, and that some customers will experience electricity outages.

The results of resource adequacy analyses are typically described by using one or more metrics that aim to capture key concepts associated with the possible loss of electricity service. Two resource adequacy metrics are commonly used, each of which captures different aspects of an electricity system's resource adequacy.

- **Loss of load hours (LOLH):** the estimated number of hours over a defined period that generation supplies will be inadequate to meet demand

- **Loss of load expectation (LOLE):** the estimated number of days over a defined period that generation supplies will be inadequate to meet demand at least once during that day

These metrics represent different aspects of a system's reliability, encompassing the frequency, duration, and magnitude of generation shortfalls. A higher value for any of these metrics indicates an electricity system that will experience more instances in which generation supplies are inadequate. Accordingly, "target" levels of resource adequacy for an electric utility are usually defined by a maximum acceptable value for one or more of these metrics, such that the electricity system will be assessed to have resource adequacy only if the metric reported from the analysis is below its target level. To illustrate, common practice in the U.S. electricity industry is for utility resource adequacy to be sufficient such that LOLE is no higher than 1 day per decade or 0.1 days per year.

Support for probability-based resource adequacy assessments has increased due to changing electricity load profiles (e.g., the addition of customer-sited rooftop solar, the adoption of electric vehicles), the growth of intermittent renewable resources (e.g., solar and wind), and other factors that affect resource adequacy. Recent NERC surveys[1] indicate that most regional electricity systems in North America are using probabilistic approaches to examine resource adequacy questions, and if they are not, they are considering incorporating probabilistic approaches.

In today's electricity industry, best-practice resource adequacy assessment often begins by establishing a goal or target level for the maximum acceptable number or duration of instances when supply is insufficient to meet System Load. Frequently, target levels for loss of load expectation (LOLE) and loss of load hours (LOLH) are set to establish a goal for the region's resource adequacy. For example, in the U.S. electricity industry, common practice is that expected LOLE should be no higher than 0.1 days per year. Then, a probabilistic approach for modeling supply and demand on the electricity system is undertaken to estimate the expected LOLE or the expected LOLH for the electricity system in its current configuration. This type of resource adequacy assessment better incorporates the greater degree of statistical variance in the performance of an electricity system based on an increasing share of intermittent renewables.

Utilizing the results from a resource adequacy study, it is ultimately the responsibility of the regulator to approve any plan subsequently developed to improve resource adequacy, often through an integrated resource planning (IRP) process.

In addition to supporting the development of plans to add new resources to serve System Load, resource adequacy analyses can also help utilities set more appropriate planning or operating criteria, such as a requirement to maintain in operating reserves enough generation to cover the loss of the largest generator in the system or a requirement to schedule power plant maintenance during specific months or seasons.

C.1 Resource Adequacy Practices Elsewhere

A comparison of resource adequacy approaches for selected other utilities and planning entities is provided below. Utilities and planning entities considered in this review were selected based on having similar characteristics to Puerto Rico, including other islands and other parts of the U.S. mainland with similar climate and renewable integration goals.

Resource Adequacy for Other Islands

Maintaining high levels of system resource adequacy is especially challenging for electricity systems that serve islands far removed from a continental landmass. The main reason for this is that islands cannot 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 remaining online that could be dispatched to cover for the large generator's outage. Meanwhile, 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.

To compare with Puerto Rico, resource adequacy methodologies were reviewed for three U.S.-based Island electricity systems: the U.S. Virgin Islands, Hawaii and Guam. A summary of the resource adequacy targets used for these three island electricity systems is provided in Table C-1 below.

Table C-1: Resource Adequacy Standards Used in Other Islands Similar to Puerto Rico

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[10]
Hawaiian Electric Company	Energy Reserve Margin, based on 1 day per 4.5 years
Guam Power Authority	1 day per 4.5 years[12]

U.S. Virgin Islands

As one of Puerto Rico's Island neighbors, the U.S. Virgin Islands (USVI) has several similarities to Puerto Rico from a generation resource adequacy perspective. Neither the USVI nor Puerto Rico 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 USVI, the Virgin Islands Water and Power Authority (VIWAPA), released an updated IRP in 2020, where they discussed several items related to resource adequacy considerations.[10] The IRP planning horizon spanned 2020–2044 and noted the requirement that 50 percent of electricity generation in the USVI (as a percentage of peak demand) must come from

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[10] VIWAPA Final IRP Report, 21 July 2020.

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 the two largest generators or two most important transmission lines.

Hawaii

From a resource adequacy perspective, Hawaii also shares several similarities with Puerto Rico. Both Hawaii and Puerto Rico cannot import electricity from neighbors, have similar climates, and both are undergoing the integration of an increasing quantity of renewable resources towards a target of 100% renewables.

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 state regulatory authority (the Hawaiian Public Utility Commission, or HPUC) titled the 2025 Adequacy of Supply.[11] In the HPUC filing for the 2021 Adequacy of Supply, HECO notes some modifications to its 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 LOLE to be less than one day per 4.5 years, and as of the 2025 Adequacy of Supply report the ERM for O'ahu is 30%.

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:

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

In the above equation, the hourly dependable capacity of each 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 generates 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 (GPA). As an island with a similar climate to Puerto Rico, Guam shares many similar resource adequacy challenges as Puerto Rico. GPA is

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11 Hawaiian Electric Company Inc., Adequacy of Supply, 30 January 2025.

currently developing an updated IRP; however, previous IRP filings note the island targets a one day per 4.5 years LOLE resource adequacy risk measure [12] GPA indicates that at least a 60% PRM is required to meet this level of resource adequacy. Like VIWAPA in the U.S. Virgin Islands, GPA also utilizes an “N-2” planning criteria, requiring sufficient generation to cover the simultaneous loss of the island’s two largest generating sources.

Resource Adequacy for Selected Other U.S. Locations

Across the mainland United States, the critical power system priorities are to achieve and maintain reliable, resilient, and secure capacity and energy that is clean and affordable. Many utilities are subject to Renewable Portfolio Standards (RPS) and carbon emission reduction goals while maintaining Loss of Load Expectations (LOLE) within the industry LOLE standard of 1 day in 10 years.

For instance, in PJM (the grid operator in the vast region from Chicago to Washington DC to Newark NJ, with over 100,000 MW of generating capacity), the recommendation is to maintain an Installed Reserve Margin (IRM) of 17.8% for 2025/2026 based on installed capacity and the forecast annual peak demand.[13]

Detailed comparisons of resource adequacy practices on non-island, U.S. utilities and planning regions more similar to Puerto Rico are discussed below. [14] [15] [16] [17]

Florida

As the closest state to Puerto Rico, Florida shares similarities with Puerto Rico in terms of climate and solar energy potential and growth. The resource adequacy methodologies used by two utility planning entities within Florida were assessed: the Florida Reliability Coordinating Council and Florida Power & Light.

Florida Reliability Coordinating Council

The Florida Reliability Coordinating Council (FRCC) is a regional entity responsible for assessing and ensuring reliable operation of the bulk power system in Florida, as is required by the state regulatory authority (the Florida Public Services Commission, or FPSC). FRCC is comprised of several different member organizations, including 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. [18] This plan projects electrical system performance for the FRCC region by analyzing reserve margins, LOLP, forced outage rates, and other related items.

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[12] Guam Power Authority 2022 Integrated Resource Plan.

[13] Installed Reserve Margin (IRM), Forecast Pool Requirement (FPR), and Effective Load Carrying Capacity (ELCC) for 2025/2026 BRA; PJM Resource Adequacy Planning, March 20, 2024

[14] California Independent System Operator, Resource Adequacy Working Group Discussion Paper, September 2023

[15] Florida Power and Light (FPL), Ensuring Reliable Service, https:/www.fpl/reliability.html

[16] California Independent System Operator, Resource Adequacy Working Group Discussion Paper, September 2023

[17] 2023 PJM Reserve Requirement Study, PJM Resource Adequacy Planning, December 29, 2023

[18] FRCC 2025 Load & Resource Reliability Assessment Report V1, 13 June 2025.

Florida Power & Light

Within the FRCC region, Florida Power & Light (the largest utility in the state) conducts its own jurisdictional resource planning analysis in accordance with state policies. [19] While Florida Power & Light also plans for a target LOLE of 0.10 days/year, the utility also enforces two other resource adequacy criteria:

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

The planning criteria above are unique in that they address the desire for diversification in how resource adequacy needs are met within Florida, showing how utilities can set unique planning criteria based on the characteristics of their specific location.

California

Among regional electricity systems around the world, California is a leader in many aspects of transitioning to an electricity supply based heavily on distributed renewable energy.

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. By comparison, Puerto Rico is also currently pursuing significant growth in solar generation to meet the island's own renewable portfolio standard of 100% by 2050. The state regulatory authority (California Public Utilities Commission, or CPUC) establishes resource adequacy obligations for all load serving entities (LSE) supplying to retail electricity customers, including the three investor-owned utilities (e.g., Southern California Edison, Pacific Gas & Electric, San Diego Gas & Electric), within state jurisdiction.[20] The state resource adequacy program for each LSE contains three distinct requirements:

- Load serving entities are required to meet an increasing PRM target of 16% for 2023 and 17% for 2024 and 2025 on top of their approved load forecast (up from the previous 15% target).
- 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).
- 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 monthly). The reason for this resource adequacy requirement stems from the fact that there is a significant amount of intermittent generation (i.e., solar energy) installed in 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

[19] Florida Power & Light Company, Ten Year Power Plant Site Plan 2025-2034
[20] California Public Utilities Commission, 2023 Resource Adequacy Report.

such as energy storage, fast-ramping thermal units (such as engines, combustion turbines, combined cycles), etc.

At the wholesale level, taking resource adequacy to a higher level and setting goals monthly instead of annually, the California ISO has implemented the “Slice-of-Day" program,[21] which requires each capacity and generation entity to demonstrate enough capacity to satisfy its forecast load in all 24 hours of the “Worst Day” (the day with the highest peak load) of each month.

The CPUC performs detailed analyses to determine the generator's effective load-carrying capacity (ELCC), which is the fraction of rated capacity that a generator can contribute toward resource adequacy requirements. The ELCC of a generator is defined by how much System Loads can increase when the generator is added to the electrical system, with equivalent performance in terms of system resource adequacy. In California, the ELCC calculation is based on the enforcement of a 0.10 days/year LOLE target[22].

The ELCC of a generator varies by technology type and the capability of the generator to contribute towards serving the load when generation is needed most. For example, if generation were needed to meet a load peak occurring 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 also vary from one planning region to another because the timing and duration of peak demand levels differ from region to region.

In summary, Table C-2 presents the key resource adequacy considerations for the above geographies (along with selected other geographies). The column labelled “Target Adequacy Risk Measures” indicates the target levels of loss of load that each region’s planning entity strives to meet. For example, a value of “0.1 days per year” means that the electricity system should assign a 10% probability that, in any given year, there will be an occasion in which the load cannot be fully served by available resources.

Table C-2: Comparison of Resource Adequacy Methodologies

Utility / Planning Entity	Target Risk Measure (LOLE, LOLP, LOLH, or other)	Notes
Virgin Islands Water and Power Authority	LOLE 1 day/year in 2020, declining to 0.1 days/year in 2044	U.S. territory islands neighboring Puerto Rico have, similar climate and a lack of electricity import ability. An additional N-1-1 planning criterion requires sufficient installed capacity to cover the loss of the two largest resources. Target LOLE for 2044 is a recent goal outlined in the 2019 IRP. [10]

[21] California Independent System Operator, Resource Adequacy Working Group Discussion Paper, September 2023
[22] Incremental ELCC Study For Mid-Term Reliability Procurement. January 2023 Update.

NEPR-MI-2022-0002

Utility / Planning Entity	Target Risk Measure (LOLE, LOLP, LOLH, or other)	Notes
Hawaiian Electric Company	Energy Reserve Margin (ERM), based on LOLE 1 day/4.5 years	A U.S island with a similar load profile, generation, climate, and inability to import electricity as exists in Puerto Rico. HECO bases its resource adequacy criteria on a one-day per 10-year guideline for assessing resource adequacy. This LOLE target helps to inform the ERM 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).[11]
Guam Power Authority	LOLE 1 day/4.5 years	A 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%[12]
Florida Reliability Coordinating Council	LOLE 0.1 days/year	Florida has a similar climate to Puerto Rico, and a 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.[18]
Florida Power & Light	LOLE 0.1 days/year	Florida Power & Light is a vertically integrated utility located in Florida. In addition to the 0.1 day/year LOLE 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.[19]
California Public Utilities Commission	LOLE 0.1 days/year	CPUC's 2023 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 2023 and 17% in 2024 to maintain the traditional 0.1 days per year LOLE standard, accounting for increased load forecasts.[20]

NEPR-MI-2022-0002

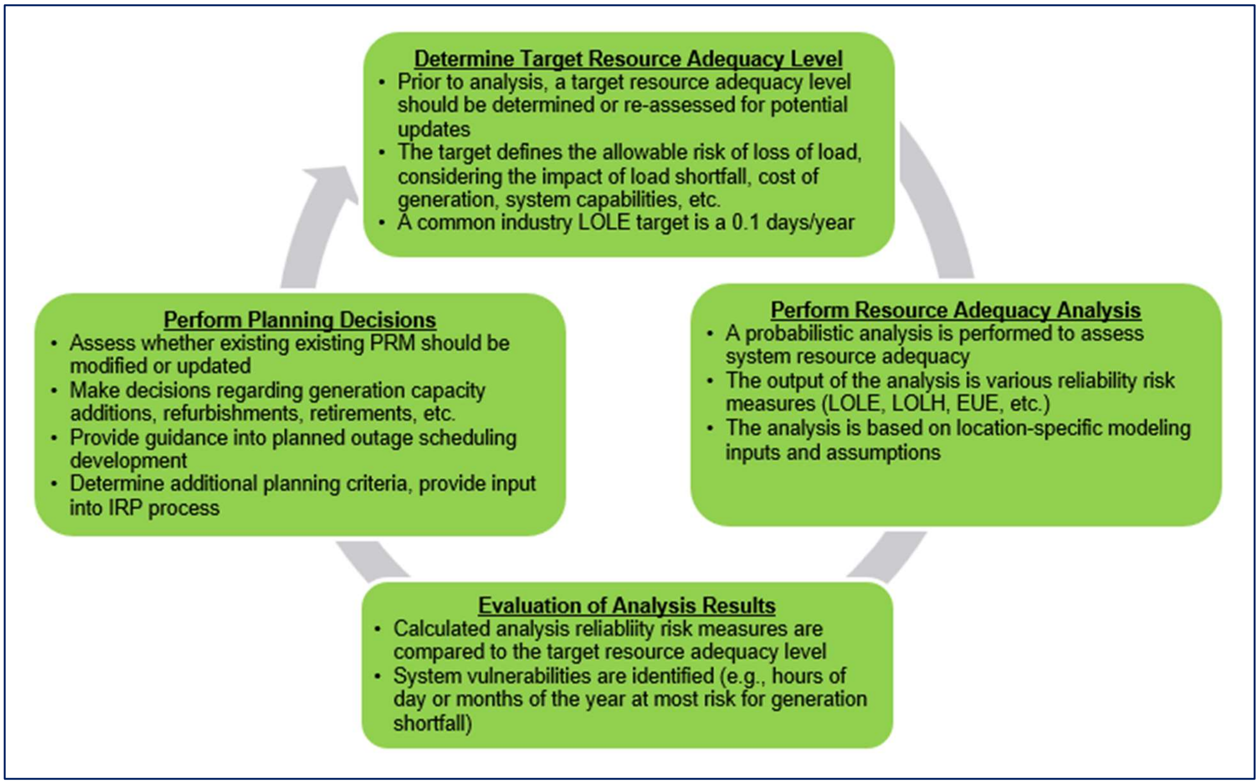
Utility / Planning Entity	Target Risk Measure (LOLE, LOLP, LOLH, or other)	Notes
Arizona Public Service Company	LOLE 0.1 days/year	Arizona Public Service Company has a 100% clean energy goal for 2050 that includes carbon-free resources like solar, wind, demand-side management, and nuclear. As part of the 2030 interim clean energy goal, a 45% requirement for renewable generation is required. Results from Arizona Public Services' 2023 IRP Reserve Margin Study indicate an increase in PRM from 15% to 20.2% in order to meet the industry standard of 0.1 LOLE days per year.[23]
Tucson Electric Power (Arizona)	16.5% Planning Reserve Margin	Tucson Electric Power is a utility in the desert southwest region of the U.S. with high solar potential. The utility follows a 16.5% planning reserve margin guideline, supported by various probabilistic analyses and an increase from their 2020 IRP's 15% target. The referenced IRP investigates numerous renewable penetration levels, and the utility has set 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.[24]
Public Service Company of New Mexico	LOLE 0.1 days/year	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 a 100% emissions-free goal by 2040. It also transitioned to the industry standard LOLE of 0.1 days per year, compared to the 2020 IRP target of 0.2 days per year.[25]
Puget Sound Energy (Washington state)	LOLP of 5% per year	Puget Sound Energy is required by Washington 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.[26]

[23] Arizona Public Service Company 2023 Integrated Resource Plan, November 1 2023
[24] Tuscon Electric Power 2023 Integrated Resource Plan, November 1 2023
[25] PNM's 2023 Integrated Resource Plan, December 15 2023
[26] Puget Sound Energy 2023 Electric Progress Report, March 31 2023

C.2. Resource Adequacy Assessment Process

The basic steps involved in performing a resource adequacy analysis are depicted in Figure C-1. The first step in resource adequacy assessment is to identify the target level of the preferred metric(s) to be achieved. In the second step, probabilistic modeling is used to calculate the expected degree of resource adequacy that will be achieved, based on data and assumptions about the electricity system's supply and demand. The third step compares estimated resource adequacy against a target level of resource adequacy to identify potential shortfalls in expected resource adequacy, and spotlight potential causes and circumstances under which resources will be inadequate. Finally, generation additions, retirements, and other programs can be recommended – often as part of an integrated resource process (IRP) -- to improve resource adequacy.

Figure C-1: Resource Adequacy Process Flowchart



Of the above-noted four steps, the second step, involving the quantitative estimation of resource adequacy, merits additional discussion here.

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. In turn, these tools are critically dependent upon numerous assumptions about both supply and demand on the electricity system being evaluated. The probabilistic estimation of resource adequacy results from the following three activities:

- Demand levels for each of the 8,760 hours in a year are estimated for an upcoming year, using historical data as a baseline, adjusting for any abnormal weather conditions and adding forecasted growth from the historical year to the future year.
- For each of the 8,760 hours in a year, accounting for power plant outage rates and outage durations, the many possible permutations of aggregate generation supply availability in any given hour are considered, and a probability is calculated for each permutation to occur in what is called a Monte Carlo simulation.
- Each of the supply permutations in a given hour and its probability of occurring is evaluated against the expected demand in that hour to calculate the fraction of possible outcomes in which supply will not be adequate to meet demand.

For this resource adequacy assessment, an industry-approved probabilistic iterative method using NREL's Probabilistic Resource Adequacy Suite (PRAS) of models was used.

As part of the PRAS model validation, a thorough benchmarking process was undertaken to verify its simulation output relative to the use of 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.[9] The validation process illustrated strong agreement between the PRAS model and other 3rd party production cost and dispatch simulation tools.

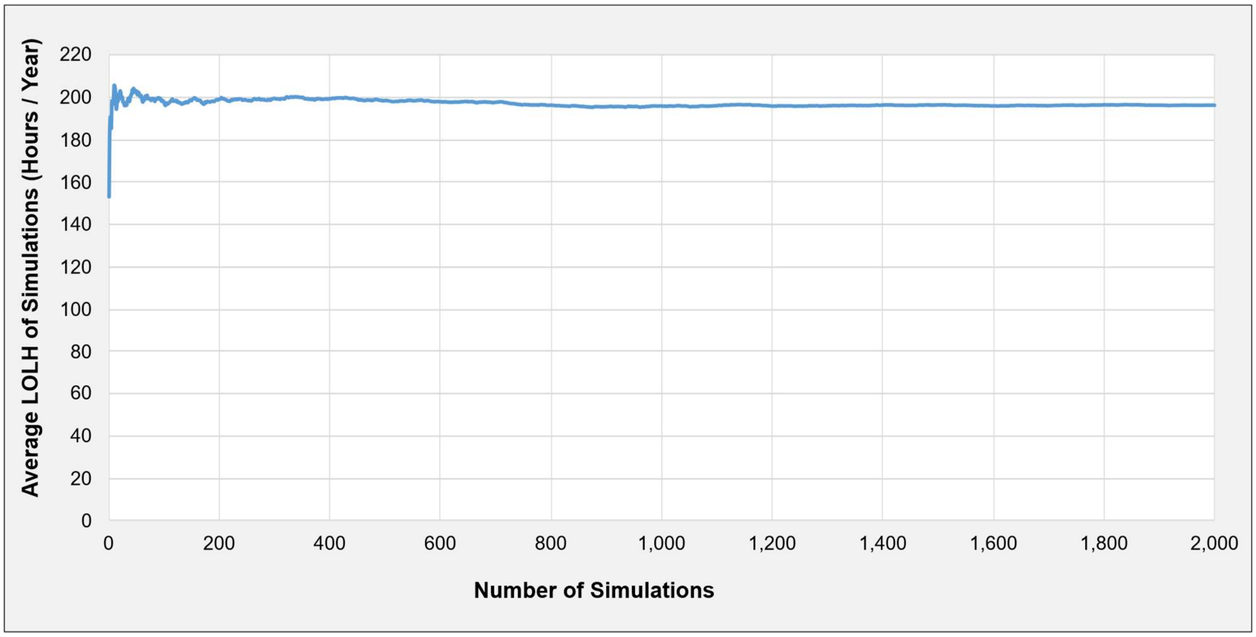
All hours of FY2025 were simulated in PRAS, calculating whether there will be sufficient available generation capacity to meet load for each hour of the year. Since the timing of power plant forced outages is random, thus randomly affecting when a power plant will be able to generate electricity in any given hour, each hour of the year is re-simulated multiple times using a statistical technique called Monte Carlo analysis.

With Monte Carlo analysis, each simulation for a given hour involves the application of outage probability at each power plant to arrive at an aggregate resource availability that can then be compared to the expected load in that hour. When an hour is simulated many times, with each simulation producing a judgment of resource sufficiency or resource deficit, an estimate of the overall probability of resource adequacy in that hour emerges. If the simulation were repeated an infinite number of times, then the true probability of resource adequacy would be yielded. However, since it would take an infinite amount of time to computationally estimate anything an infinite number of times, the number of simulations is set at a high but finite number (2,000 simulations) so that the results "converge": the change in estimated resource adequacy measures that result from an additional simulation is miniscule. By evaluating the aggregated results from all simulations after convergence has been achieved, one can quantify the risk (i.e., the probability) of not meeting System Load due to resource deficiency.

The following Figure C-2 helps to illustrate the convergence of the PRAS model calculation process. In this graph, the x-axis represents the number of simulations performed, and the y-axis represents the average of estimated loss of load hours (LOLH) over all simulations performed. The blue line suggests that the first simulation produced an estimated LOLH of roughly 150. The second simulation produced a much higher estimated LOLH, jumping to an estimated LOLH of 181, and during the first 100 iterations, we see a maximum estimated LOLH of about 205.

As more simulations were completed, the average LOLH stabilized around a value of 196 – the final value reported for Base Case LOLH. As can be seen in Figure C-2, convergence at an LOLH of 196 is achieved relatively quickly in the calculation process (approximately 500 iterations into the simulation). At that point, results could generally be considered to have converged. Even so, for additional robustness, an additional 1,500 simulations were completed beyond 500 iterations. All results from the PRAS model presented in this report were obtained after 2,000 iterations.

Figure C-2: Average LOLH Converges as Number of Iterations Increases



The above set of steps describes the process for performing a resource adequacy analysis under one set of assumptions about generation supply and demand. However, it is common in resource adequacy studies to perform the above modeling steps under multiple sets of assumptions. This includes estimating the potential impacts on resource adequacy of different "states of the world" (i.e., scenario analysis) as well as evaluating the effects on resource adequacy of an incremental increase or decrease in one narrow aspect of assumptions (i.e., sensitivity analysis).

C.3 NERC Guidance on Resource Adequacy Practices

Support for probability-based resource adequacy methodologies such as those described above has increased in recent years due to the growth of intermittent (renewable) resources and shifting peak hours for electricity demand, amid other factors. As the primary authority for electricity system reliability in the U.S., the North American Electricity Reliability Council (NERC) has led the advancement of probabilistic resource adequacy practices that better account for these changing conditions facing the electricity industry. While Puerto Rico is not under NERC jurisdiction, as an acknowledged world-leader on resource planning methodologies, Puerto Rico is well-served by taking advantage of NERC guidance on resource adequacy practices.

NEPR-MI-2022-0002

In March 2011, NERC released a guideline report, *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning* [27] .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 via the use of additional metrics other than solely PRM.

In 2017, FERC approved NERC Reliability Standard BAL-502-RF-03[28], which created requirements for entities registered as planning coordinators to perform and document resource adequacy analyses. The standard states that a region's PRM should be set such that the average LOLE is equal to 0.10 days per year, a target that has since become widely adopted across the U.S. The standard also provides guidance on matters including load forecast characteristics, resource characteristics, and transmission limitations that prevent delivery of generation reserves in the resource adequacy analysis.

Continuing this expanding resource adequacy guidance, NERC in 2018 released the technical reference report, *Probabilistic Adequacy and Measures* [29] Due to the evolving resource mix landscape resulting from 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 profiled in the report range from relatively simple calculations of PRMs to extensive generation resource adequacy simulations that calculate system loss of load probability (LOLP) values.

Recent NERC surveys[30] indicate that most regions in North America are now using probabilistic approaches to examine resource adequacy questions, and if they are not, they are considering incorporating probabilistic approaches.

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[27] North American Electric Reliability Corporation, March 2011.
[28] North American Electric Reliability Corporation, October 2017.
[29] North American Electric Reliability Corporation, July 2018.
[30] North American Electric Reliability Corporation, Probabilistic Adequacy And Measures, July 2018.

Appendix D: Puerto Rico Electric System Fleet

This appendix summarizes Puerto Rico's electric system fleet as it is currently, and the upcoming utility-scale projects. Since the scope of this report only covers one full year (FY2026), it does not consider any unit retirement from the currently available units. However, some of the units listed in Table D-1 that are considered not available are currently in the process of decommission or are pending to be decommissioned soon.

Puerto Rico Current Electric System Fleet

Table D-1 below shows all thermal resources, categorized by unit name, start of operation year, fuel type, nameplate capacity, available capacity, and estimated forced outage rate for FY2026, whose available capacity and forced outage rates were estimated by analysis of previous years' performance. Note that some units do not have the start of operation year since that information is not available.

Table D-1: Puerto Rico Thermal Electric Fleet

Generator Name	Start of Operations	Fuel	Nameplate Capacity (MW)	Available Capacity (MW)	Forced Outage Rate (%)
AES 1	2002	Coal	227	227	[redacted]
AES 2	2002	Coal	227	227	[redacted]
Aguirre Combined Cycle 1	1977	Diesel	296	150	50
Aguirre Combined Cycle 2	1977	Diesel	296	130	60
Aguirre Steam 1	1971	Bunker C	450	300	30
Aguirre Steam 2	1971	Bunker C	450	340	20
Aguirre 2-1	-	Diesel	21	Not Available	-
Aguirre 2-2	-	Diesel	21	Not Available	-
Cambalache 1	1998	Diesel	82.5	Not Available	-
Cambalache 2	1998	Diesel	82.5	78	10
Cambalache 3	1998	Diesel	82.5	78	15

NEPR-MI-2022-0002

Generator Name	Start of Operations	Fuel	Nameplate Capacity (MW)	Available Capacity (MW)	Forced Outage Rate (%)
Costa Sur 1	-	Bunker C	50	Decommissioned	-
Costa Sur 2	-	Bunker C	50	Decommissioned	-
Costa Sur 3	-	Bunker C	85	Decommissioned	-
Costa Sur 4	-	Bunker C	85	Decommissioned	-
Costa Sur 5	1972	Natural Gas / Bunker C	410	330	20
Costa Sur 6	1973	Natural Gas / Bunker C	410	350	15
Costa Sur 1-1	-	Diesel	21	Not Available	-
Costa Sur 1-2	-	Diesel	21	Not Available	-
Culebra 1	2020	Diesel	2	2	-
Culebra 2	2020	Diesel	2	2	-
Culebra 3	2020	Diesel	2	2	-
Daguao 1-1	-	Diesel	21	21	40
Daguao 1-2	-	Diesel	21	21	40
EcoElectrica	1999	Natural Gas	545	545	[redacted]
Jobos 1-1	-	Diesel	21	Not Available	-
Jobos 1-2	-	Diesel	21	21	40
Palo Seco 1	1964	Bunker C	85	Decommissioned	-
Palo Seco 2	1964	Bunker C	85	Decommissioned	-
Palo Seco 3	1968	Bunker C	216	170	15

NEPR-MI-2022-0002

Generator Name	Start of Operations	Fuel	Nameplate Capacity (MW)	Available Capacity (MW)	Forced Outage Rate (%)
Palo Seco 4	1968	Bunker C	216	180	25
Palo Seco 1-1	-	Diesel	21	21	40
Palo Seco 1-2	-	Diesel	21	21	40
Palo Seco 2-1	-	Diesel	21	21	40
Palo Seco 2-2	-	Diesel	21	Not Available	-
Palo Seco 3-1	-	Diesel	21	Not Available	-
Palo Seco 3-2	-	Diesel	21	Not Available	-
San Juan 7	1965	Bunker C	100	90	45
San Juan 8	1966	Bunker C	100	Not Available	-
San Juan 9	1968	Bunker C	100	90	5
San Juan 10	1968	Bunker C	100	Not Available	-
San Juan Combined Cycle 5	2008	Natural Gas / Diesel	220	210	CT: 5 STG: 15
San Juan Combined Cycle 6	2008	Natural Gas / Diesel	220	210	CT: 10 STG: 20
Mayagüez 1	2009	Diesel	55	50	30
Mayagüez 2	2009	Diesel	55	50	30
Mayagüez 3	2009	Diesel	55	25	30
Mayagüez 4	2009	Diesel	55	25	30
Vega Baja 1-1	-	Diesel	21	Not Available	-

NEPR-MI-2022-0002

Generator Name	Start of Operations	Fuel	Nameplate Capacity (MW)	Available Capacity (MW)	Forced Outage Rate (%)
Vega Baja 1-2	-	Diesel	21	Not Available	-
Vieques 1	2008	Diesel	3	3	-
Vieques 2	2008	Diesel	3	3	-
Yabucoa 1-1	-	Diesel	21	Not Available	-
Yabucoa 1-2	-	Diesel	21	21	40
3 Palo Seco Mobile Pack	2021	Diesel	3x27	81	40 each
4 TM Gens (Palo Seco)	2023	Natural Gas / Diesel	2x20 + 2x25	90	10-20
10 TM Gens (San Juan)	2023	Natural Gas / Diesel	10x25	250	10-30
Total			**6,302**	**4,435**	

Table D-2 below summarizes all the utility-scale renewable projects currently online. There are 7 solar projects, with a capacity totaling 147.1 MW, 2 wind projects that add up to 121 MW capacity, and 2 landfill projects for 4.8 MW of capacity, for a total of 272.9 MW of renewables capacity. Note that, since 2016, no new solar projects have been interconnected; however, by the end of 2025, and through 2026, multiple new solar projects are expected to become available. See Table D-3 for the list of future upcoming projects for the Puerto Rico fleet.

Table D-2: Utility Scale Renewable Resources on Puerto Rico

Generator Name	Commercial Operation Date	Source	Nameplate Capacity (MW)
AES Illumina	2012	Solar	20
Fonroche Humacao	2016	Solar	40

NEPR-MI-2022-0002

Generator Name	Commercial Operation Date	Source	Nameplate Capacity (MW)
Horizon Energy	2016	Solar	10
Oriana Energy	2016	Solar	45
San Fermin Solar	2015	Solar	20
Cantera Martinó (Windmar)	2011	Solar	2.1
Vista Alegre / Coto Laurel (Windmar)	2016	Solar	10
Pattern (Santa Isabel)	2012	Wind	95
Punta Lima	2024	Wind	26
Toa Baja Landfill Tech	2016	Methane Gas	2.4
Fajardo Landfill Tech	2016	Methane Gas	2.4
Total			**272.9**

Upcoming Utility Scale Projects

Table D-3 below summarizes all the upcoming utility-scale projects for the Puerto Rico electricity system, consisting of multiple resources such as Thermal, Solar, BESS, and transmission additions.

Table D-3: Upcoming Utility-Scale Projects for Puerto Rico

Program Category	Project Name	Project Type	Approved & Executed Contracts (MW)	Proposed Additions (MW)	Energy Storage Duration (hrs)	COD*
Tranche 1	CFE Salinas	Energy Storage	175	0	4 hours	3/30/2026
Tranche 1	CFE Jobos	Energy Storage	110	0	4 hours	9/30/2026
Tranche 1	Peñuelas	Energy Storage	100	0	4 hours	3/30/2027
Tranche 2	Canadian Vega Baja	Energy Storage	60	0	4 hours	TBD
Tranche 1	Pattern Barceloneta	Energy Storage	50	70	4 hours	2/28/2027
Tranche 1	Patten Santa Isabel	Energy Storage	50	50	4 hours	4/30/2027
Tranche 4	Isabela	Energy Storage	50	0	6 hours	TBD
Tranche 1	Ponce	Energy Storage	25	0	4 hours	3/30/2027
Tranche 1	Caguas	Energy Storage	25	0	4 hours	3/30/2027
Tranche 1	Yabucoa Energy Park	Energy Storage	0	80	4 hours	12/30/2026
Tranche 1	Naguabo Energy Park	Energy Storage	0	80	4 hours	6/30/2027

NEPR-MI-2022-0002

Program Category	Project Name	Project Type	Approved & Executed Contracts (MW)	Proposed Additions (MW)	Energy Storage Duration (hrs)	COD*
Genera PR BESS	Vega Baja	Energy Storage	49	0	4 hours	11/30/2025
Genera PR BESS	Aguirre	Energy Storage	158	0	4 hours	12/30/2025
Genera PR BESS	Cambalache	Energy Storage	52	0	4 hours	1/30/2026
Genera PR BESS	Palo Seco	Energy Storage	101	0	4 hours	3/30/2026
Genera PR BESS	Costa Sur	Energy Storage	30	0	4 hours	4/30/2026
Genera PR BESS	Yabucoa	Energy Storage	40	0	4 hours	6/30/2026
Accelerated Storage Addition Program (ASAP) - Standard Offer 1	Oriana Energy	Energy Storage	0	50	4 hours	5/30/2026
Accelerated Storage Addition Program (ASAP) - Standard Offer 1	Polaris	Energy Storage	0	40	4 hours	5/30/2026
Accelerated Storage Addition Program (ASAP) - Standard Offer 1	Fonroche	Energy Storage	0	40	4 hours	5/30/2026

NEPR-MI-2022-0002

Program Category	Project Name	Project Type	Approved & Executed Contracts (MW)	Proposed Additions (MW)	Energy Storage Duration (hrs)	COD*
Accelerated Storage Addition Program (ASAP) - Standard Offer 1	Horizon Energy	Energy Storage	0	18	4 hours	5/30/2026
Accelerated Storage Addition Program (ASAP) - Standard Offer 1	San Fermin	Energy Storage	0	20	4 hours	5/30/2026
Accelerated Storage Addition Program (ASAP) - Standard Offer 1	EcoEléctrica	Energy Storage	0	20	4 hours	5/30/2026
LUMA 4X25	Vega Baja TC	Energy Storage	0	25	4 hours	12/30/2027
LUMA 4X25	Monacillos TC	Energy Storage	0	25	4 hours	12/30/2027
LUMA 4X25	Barceloneta TC	Energy Storage	0	25	4 hours	12/30/2027
LUMA 4X25	Aguadilla TC	Energy Storage	0	25	4 hours	12/30/2027
Accelerated Storage Addition Program (ASAP) - Standard Offer 2	Ciro One Salinas	Energy Storage	0	167	4 hours	TBD

NEPR-MI-2022-0002

Program Category	Project Name	Project Type	Approved & Executed Contracts (MW)	Proposed Additions (MW)	Energy Storage Duration (hrs)	COD*
Accelerated Storage Addition Program (ASAP) - Standard Offer 2	Guayama Solar Energy	Energy Storage	0	80	4 hours	TBD
Accelerated Storage Addition Program (ASAP) - Standard Offer 2	San Fermin Solar Farm	Energy Storage	0	75	4 hours	TBD
Accelerated Storage Addition Program (ASAP) - Standard Offer 2	XZERTA-TEC	Energy Storage	0	60	4 hours	TBD
Accelerated Storage Addition Program (ASAP) - Standard Offer 2	Ciro Two	Energy Storage	0	58	4 hours	TBD
Accelerated Storage Addition Program (ASAP) - Standard Offer 2	Yabucoa YFN	Energy Storage	0	50	4 hours	TBD
Accelerated Storage Addition Program (ASAP) - Standard Offer 2	Fonroche	Energy Storage	0	40	4 hours	TBD

NEPR-MI-2022-0002

Program Category	Project Name	Project Type	Approved & Executed Contracts (MW)	Proposed Additions (MW)	Energy Storage Duration (hrs)	COD*
Accelerated Storage Addition Program (ASAP) - Standard Offer 2	Punta Lima Wind Farm	Energy Storage	0	40	4 hours	TBD
Accelerated Storage Addition Program (ASAP) - Standard Offer 2	Solaner	Energy Storage	0	40	4 hours	TBD
Accelerated Storage Addition Program (ASAP) - Standard Offer 2	Tetris Power	Energy Storage	0	20	4 hours	TBD
Accelerated Storage Addition Program (ASAP) - Standard Offer 2	Landfill Gas Technologies Fajardo	Energy Storage	0	10	4 hours	TBD
Accelerated Storage Addition Program (ASAP) - Standard Offer 2	Landfill Gas Technologies Toa Baja	Energy Storage	0	10	4 hours	TBD
Accelerated Storage Addition Program (ASAP) - Standard Offer 2	CS-UR JUNCOS PV (Juncos I PV)	Energy Storage	0	4	4 hours	TBD
Other-High Voltage Distribution Cable	Hostos	Other- Generation	0	500	N/A	TBD

NEPR-MI-2022-0002

Program Category	Project Name	Project Type	Approved & Executed Contracts (MW)	Proposed Additions (MW)	Energy Storage Duration (hrs)	COD*
Tranche 1	CS/UR Juncos Solar	Solar Generation	125	0	N/A	10/30/2027
Tranche 1	CFE Salinas	Solar Generation	120	0	N/A	3/30/2026
Tranche 1	Coamo	Solar Generation	100	0	N/A	3/30/2027
Non-Tranche	Ciro One Phase 1	Solar Generation	90	0	N/A	12/1/2025
Tranche 1	CFE Jobos	Solar Generation	80	0	N/A	9/30/2026
Tranche 1	Barceloneta	Solar Generation	70	0	N/A	2/28/2027
Tranche 1	Ciro Two	Solar Generation	68	58	N/A	TBD
Non-Tranche	Xzerta	Solar Generation	60	0	N/A	10/30/2027
Non-Tranche	Ciro One Phase 2	Solar Generation	50	77	N/A	5/30/2026
Tranche 1	Guayama	Solar Generation	50	80	N/A	TBD
Tranche 2	Marisol Power	Solar Generation	40	0	N/A	TBD
Tranche 1	Yabucoa Energy Park	Solar Generation	38.7	61.3	N/A	12/30/2026

NEPR-MI-2022-0002

Program Category	Project Name	Project Type	Approved & Executed Contracts (MW)	Proposed Additions (MW)	Energy Storage Duration (hrs)	COD*
Tranche 1	Solaner San German	Solar Generation	40	0	N/A	10/30/2026
Tranche 1	Yabucoa YFN	Solar Generation	32.1	0	N/A	4/30/2026
Tranche 2	Solar San Juan	Solar Generation	26.07	0	N/A	TBD
Tranche 1	Tetris Power	Solar Generation	20	0	N/A	3/30/2027
P3A RFP	Energiza	Thermal Generation	478	80	N/A	6/30/2028
Genera PR Peaker Replacement	Costa Sur	Thermal Generation	136	0	N/A	10/30/2027
Genera PR Peaker Replacement	Daguao	Thermal Generation	36	0	N/A	10/30/2027
Genera PR Peaker Replacement	Yabucoa	Thermal Generation	36	0	N/A	10/30/2027
Genera PR Peaker Replacement	Jobos	Thermal Generation	36	0	N/A	10/30/2027

* Commercial Operation Dates are estimated from the latest interaction with the developer.