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

IN RE: PLAN PRIORITARIO PARA LA ESTABILIZACIÓN DE LA RED ELÉCTRICA	**CASE NO. NEPR-MI-2024-0005** **SUBJECT: Motion Submitting LUMA's Updated Position Regarding Additional Temporary Generation**

MOTION SUBMITTING LUMA'S UPDATED POSITION REGARDING ADDITIONAL TEMPORARY GENERATION

TO THE HONORABLE PUERTO RICO ENERGY BUREAU:

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

I. Relevant Procedural Background

1. On February 27, 2025, this Puerto Rico Energy Bureau of the Public Service Regulatory Board ("Energy Bureau") issued a Resolution and Order ("February 27th Order") ordering LUMA to present its position in regard to a request submitted by Genera PR, LLC ("Genera") on February 25, 2025 to install additional Temporary Mobile Generators of approximately 800 MW, among others.[1] LUMA was directed to indicate in its position "the need for additional temporary generation, and the capacity thereof, if any, in light of the findings" of

[1] See *Request for Expedited Approval of Emergency Generation Capacity Solutions* ("Genera Request"). In its request Genera sought the Energy Bureau's approval to implement proposed options for temporary generation to "allow for critical maintenance to be performed on existing power plants while stabilizing the grid in the short term" and "guarantee system stability while recovery projects are performed" consisting of installing additional Temporary Mobile Generators of approximately 800 MW for 18 months; substituting damaged units with pre-owned but functional generating units; and deploying generation barges to supplement the power supply. *See* Genera Request, ¶ 6 and WHEREFORE

the Resource Adequacy Report filed by LUMA on October 31, 2024.[2] *See* February 27th Order, p. 1.

2. On March 6, 2025, LUMA filed a preliminary response stating its position in regard to Genera's request. *See Motion Submitting LUMA's Position Regarding Genera's Request for Expedited Approval of Emergency Generation Capacity Solutions* ("March 6th Motion"). LUMA indicated that there was an immediate need for additional generation to meet customer demand and maintain adequate reserve, and that the addition of approximately 800 MW would materially improve resource adequacy and would allow planned unit replacements to proceed with less risk to system reliability. *See id*., *Exhibit 1*, pp. 2, 3. LUMA cautioned, however, that it had not yet completed the site-specific, interconnection, fuel-supply, and feasibility analyses necessary to determine the full feasibility of installing the proposed 800 MW. *See id*., *Exhibit 1*, pp. 5-7.

3. On March 12, 2025, the Energy Bureau issued a Resolution and Order ("March 12th Order") ordering LUMA to submit the additional studies indicated in the March 6th Motion. *See* March 12th Order, p. 2.

4. On March 24, 2025, LUMA submitted a detailed analysis relating to Genera's proposal noting that a comprehensive assessment of individual project locations, interconnections, and fuel supply—including a System Impact Study and a Feasibility Study—required further detailed analysis to determine the full feasibility of any proposed solution. *See Motion in Compliance with Resolution and Order of March 12, 2025, and Request for Confidential Treatment.*

[2] The Resource Adequacy Report refers to a report prepared by LUMA titled *Puerto Rico Electrical System Resource Adequacy Analysis Report* and submitted to the Energy Bureau on October 31, 2024, in Case No. NEPR-MI-2022-0002, *In re: LUMA Resource Adequacy Study*.

5. On March 28, 2025, the Energy Bureau issued a Resolution and Order ("March 28th Order") whereby it established the Electric System Priority Stabilization Two-Year Plan ("Priority Stabilization Plan"). As part of the plan, the Energy Bureau authorized the initiative to procure up to 800 MW of additional emergency temporary generation, recognizing that the addition of dependable, dispatchable capacity was necessary to address the system's reserve-margin shortfall and reduce expected load shedding. *See* March 28th Order, pp. 5-7 and Attachment A.

6. On December 5, 2025, LUMA submitted its Fiscal Year 2026 Puerto Rico Electrical System Resource Adequacy Analysis Report ("FY2026 Resource Adequacy Study") in Case No. NEPR-MI-2022-0002, *In Re: LUMA Resourced Adequacy Study*. *See Motion to Submit LUMA's Fiscal Year 2026 Resource Adequacy Study and Request for Confidential Treatment*. In it, LUMA continued to identify a significant resource-adequacy deficiency and found that the addition of 900 MW of generation would improve Puerto Rico's adequacy to levels approaching mainland U.S. standards. *See id*., Exhibit 1, p. 10.

7. On August 19, 2026, the Energy Bureau issued a Resolution and Order ("August 19th Order") finding that an updated assessment from LUMA was needed on whether the generation-resource deficiency identified by LUMA in March 2025 continues to exist, the magnitude of any remaining deficiency, and the extent to which developments since that time—including changes reflected after the FY2026 Resource Adequacy Study—affect the need for the temporary generation capacity that gave rise to this proceeding. Accordingly, the Energy Bureau ordered LUMA to complete and file, within ten (10) days from the notification of the August 19th Order, an updated assessment of LUMA's position ("Updated Position") as stated in the March 6th Motion regarding the need for additional temporary generation, containing certain information specified in the August 19th Order. *See* August 19th Order, pp. 2-3.

8. On August 25, 2026, LUMA requested an extension of time, until September 4, 2026, to submit LUMA's Updated Position. *See Motion for Extension of Time to Submit LUMA's Updated Position Regarding Temporary Generation.*

9. On August 31, 2026, the Energy Bureau issued a Resolution and Order granting LUMA's request for an extension until September 4, 2026, to comply with the August 19th Order.

II. Submittal of LUMA's Updated Position Regarding Additional Temporary Generation

10. In compliance with the August 19th Order, LUMA hereby submits, as *Exhibit 1*, its resource adequacy assessment for the island's electricity grid during the summer of 2026, which evaluates whether the island's generating capacity is sufficient to meet demand and quantifies the extent of expected manual load shedding events*.* *Exhibit 1* concludes that Puerto Rico continues to face a persistent generation supply deficit of 700-850 MW, driven by an aging and degraded thermal fleet, frequent forced outages, deferred maintenance, and rising peak demand fueled by extreme heat*. See Exhibit 1*, pp. 4-5; 24-25. Thus, LUMA's overall assessment since the March 6th Motion remains unchanged. *See id*., p.5. *Exhibit 1* further states that the addition of 800 MW generation could allow Puerto Rico's electric system to reach and comply with the US Industry benchmark of having 1 loss of load expectation (LOLE) event each 10 years. *See id*., p. 23. *Exhibit 1* provides an updated analysis through August 2026, including actual manual load shed (MLS) events and updated forced outage rates, dependable capacity assumptions, and load forecasts based on 2025-2026 performance data. *See id*., pp. 5-7; 35-36. Furthermore, *Exhibit 1* compares changes from the FY2026 Resource Adequacy Report, suggesting that Puerto Rico electricity resource adequacy has maintained similar levels of inadequacy despite slight decreases in the forced outage rate and increased generation capacity availability. *See id*., pp. 6; 36.

WHEREFORE, LUMA respectfully requests that the Energy Bureau **take notice** of the foregoing; **accept** *Exhibit 1* in compliance with the Energy Bureau's directive to provide LUMA's updated position regarding additional temporary generation; and **deem** LUMA in compliance with the August 19th Order.

RESPECTFULLY SUBMITTED.

In Guaynabo, Puerto Rico, this 4th day of September 2026.

We hereby certify that we filed this Motion using the electronic filing system of this Energy Bureau and that electronic copies of this Motion will be notified via email to PREPA, via Alexis Rivera, alexis.rivera@prepa.pr.gov, and through its counsel of record Mirelis Valle Cancel, mvalle@gmlex.netand Natalia Zayas Godoy, nzayas@gmlex.net, and to Genera PR LLC, through its counsel of record Luis R. Roman-Negron, lrn@roman-negron.com; legal@genera-pr.com; regulatory@genera-pr.com.

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Exhibit 1

LUMA's Updated Position Regarding Additional Temporary Generation

LUMA's Updated Position Regarding Additional Temporary Generation

Interim Update for Summer 2026

September 4, 2026

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1.0 Executive Summary

This resource adequacy assessment is intended to provide a comprehensive evaluation of the island's electric generating capacity and determine whether it is sufficient to meet the demand. If the capacity is inadequate, it determines the extent to which manual load shedding (MLS) may be required to safeguard the system and maintain service continuity to remaining customers.

For clarifying purposes, LUMA does not own, manage or operate any generation facilities. As the system operator for Puerto Rico, LUMA carefully monitors and dispatches available generation resources – thermal power plants operated by Genera PR, EcoEléctrica and AES, along with renewable energy resources (i.e., solar, wind and landfill gas) operated by independent power producers, as well as hydroelectric power plants owned and operated by the Puerto Rico Electric Power Authority (PREPA) to meet customer demand and ensure the reliability of the overall electricity system on the island.

Resource Adequacy Summer 2026 Update: Key Findings

Beginning in July 2026, the Energy System has seen increased operational stress across the generation fleet, including a high frequency of unit trips that produced **15 MLS events in July and August alone**, aligning with historical patterns in which MLS occurs during peak evening hours when reserve margins fall below operational thresholds. These conditions emphasized the persistent challenges in real-time generation availability and reinforce the system's vulnerability during the highest-demand months. Key findings of this resource adequacy summer update include:

- **Elevated reliability risk throughout Summer 2026**
  The rise in MLS activity indicates that reliability challenges are intensifying. If extreme heat and high outage frequency persist, MLS could reach levels comparable to the summers of 2023 and 2024, which had 25 and 33 MLS respectively. This means customers are more likely to experience frequent short-notice interruptions during peak hours.

- **Generation fleet instability remains the dominant system vulnerability**
  The recent increase in unit trips highlights that improving generation reliability is more impactful than demand-side measures in stabilizing grid performance. Even modest decreases in generation availability rapidly reduce reserve margins, increase stress on remaining available units and ultimately trigger MLS events. Demand-side resources (CBES+) contributed to reducing the MLS events but did not eliminate the resource shortfalls. Supply reliability therefore depends heavily on reducing forced outages and accelerating fleet stabilization work.

- **Extreme heat is now a major driver of grid stress**
  Higher than expected temperatures have elevated demand above forecast levels, meaning planning models must increasingly account for weather-driven volatility. Operational planning for summer periods are adjusted to assume above-forecast temperatures as a baseline.

- **Base Case assumptions understate real-world exposure**
  The gap between forecasted and actual performance in FY2026 demonstrates that the system is highly sensitive to small deviations in load or availability. Sensitivity analyses are now essential for capturing the true risk profile.

- **A persistent structural supply deficit continues to shape system risk**
  As confirmed in earlier studies, Puerto Rico still faces a long-term generation shortfall of several hundred megawatts. Failures such as the Aguirre baseload unit outage exacerbate the deficit, highlighting the importance of adding, replacing and accelerating project deployment to stabilize reliability in energy supply.

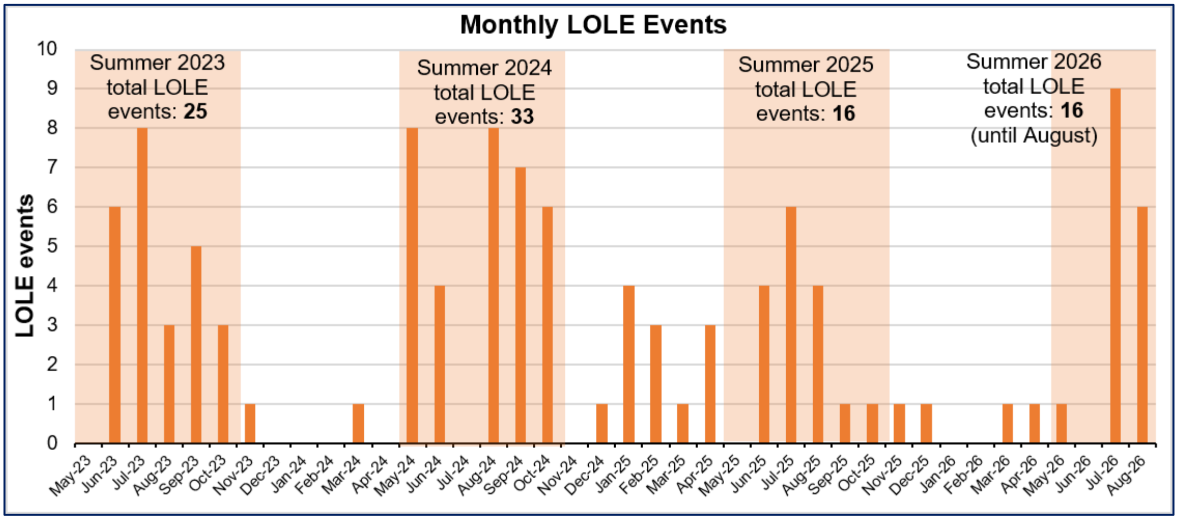
- **Impact of delayed maintenance on Summer 2026 and beyond**
  Through the spring and summer, planned maintenance across multiple generating units was deferred to mitigate immediate supply shortfalls driven by delayed unit returns to service. While this approach has temporarily supported near-term reliability, postponing maintenance increases the likelihood of higher forced outage rates in the months ahead and compresses the already limited winter maintenance window. This dynamic is expected to heighten unit unavailability and further erode operating reserve margins, adding additional stress to an already constrained system.

- The study performed for this summer update provides consistent results with the actual events experienced so far this summer. The main drivers are the higher than expected forced outate rates and higher demand due to high temperatures. This also aligns with the past three annual reports which have consistently shown a generation supply deficit ranging between 700-850 Megawatts (MW) in Puerto Rico. As the additional capacity required this year remains within that previously established range, the overall assessment is unchanged. This continued deficit further highlights the persistent fragility of the generation supply portfolio, which is further strained by the continued catastrophic failure of unit 1 at the Aguirre Power Plant.

2.0 Introduction and Context

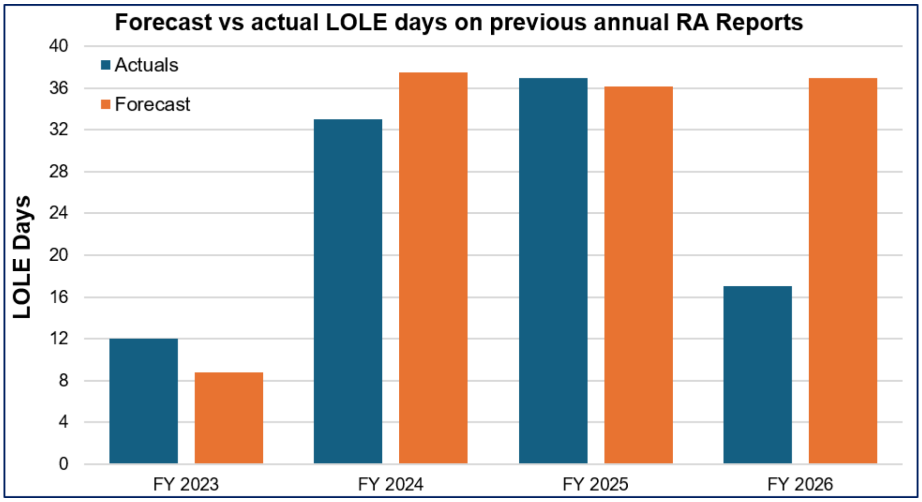
This report summarizes the results from a set of updated analyses performed by LUMA in February and August 2026 to assess the resource adequacy of the Puerto Rico electricity grid for the summer of 2026. For this study, the period considered as summer covers from May 1 until October 31, period when most of the loss of load expectation (LOLE) events occur, as Figure 1 shows from May 2023 until August 2026, showing the last three summer periods and the current summer period until August.

Figure 1. Monthly LOLE events from May 2023 through August 2026



This interim update is the most recent assessment performed by LUMA to evaluate the resource adequacy of the Puerto Rico electricity system. Using modeling methodologies like those adopted by most electric utilities, LUMA has been able to accurately forecast MLS activity in Puerto Rico in its prior annual resource adequacy studies for the last four fiscal years (FY2023 – FY2026) as shown in Figure 2 below.

Figure 2: Prior Annual Resource Adequacy Forecasts Load Shedding Prediction



Based on the findings from these prior resource adequacy studies, LUMA has consistently emphasized that electricity resources in Puerto Rico are substantially inadequate.

As shown above in Figure 2, FY2023 through FY2025 predictions have been highly accurate, supporting expectations at mid-term. However, in FY2026, variance between actuals vs forecasted has widened, with actuals considerably lower than forecasted. Since no large resource additions were expected to enter during FY2026, considering load shedding activity, and generation fleet performance in previous years, the LOLE forecast for FY2026 was similar to the FY2024 and FY2025 LOLE forecasts.

Nevertheless, actual LOLE outcome for FY2026 is mostly attributed to higher generation availability driven by multiple re-scheduled planned outages, combined with a slight decrease in load compared to previous years, leading to LOLE events reduction shown above in Figure 1.

While FY2026 LOLE actuals showed notable improvement when compared to previous fiscal years, a sharp and abrupt change began in July (beginning of FY2027), where outages clustering around key generation facilities resulted in many MLS events. These July onward events included multiple unit trips, that caused prolonged generation shortfalls. This sudden shift materially impacted the actual versus forecasted LOLE variance, causing actual generation shortfall events to increase after months of stability.

Notably, the actual number of generation shortfall events was 17 in FY2026, which significantly contrasts with the planning standard utilized by many North American utilities (which aims for only one expected generation shortfall event every 10 years – or approximately 0.1 days involving loss of load per year, representing the minimally acceptable resource adequacy). In other words, **Puerto Rico's electricity resource adequacy in FY2026 was about 170 times worse than benchmark levels set by the North American electric utility industry.**

Developments since LUMA's last resource adequacy study (FY2026 Resource Adequacy Report, issued December 5, 2025) suggest that Puerto Rico electricity resource adequacy has maintained similar levels of generation shortfalls. In response to resource performance improvements and new additions, during January 2026, LUMA revised key assumptions and undertook a new set of analyses to develop a revised perspective on Puerto Rico's resource adequacy for the summer of 2026. LUMA annually evaluates and revises key assumptions based on the most recent available data of the electric system performance to reflect the most updated changes and impacts that could have an effect on resource adequacy.

This summer update presents the findings from this set of updated resource adequacy analyses, focusing on the possible magnitude of load shedding activity that may be required during the summer 2026. Findings are presented for the six months planning period between May 1 and October 31, 2026 (which represents high demand season) in contrast to prior resource adequacy studies wherein findings were presented over the 12-month fiscal year (July 1 to June 30).

3.0 Drivers of Resource Adequacy

As with any assessment of electricity resource adequacy, the findings described herein are highly dependent upon assumptions about two fundamental sets of factors about the electricity system: the level of systemwide electricity demand to be served by the grid, and the availability of generation resources to supply demand. Both sets of factors have changed in ways that increase the strains on the already-challenged Puerto Rico electricity system, and each of these sets of factors is discussed below.

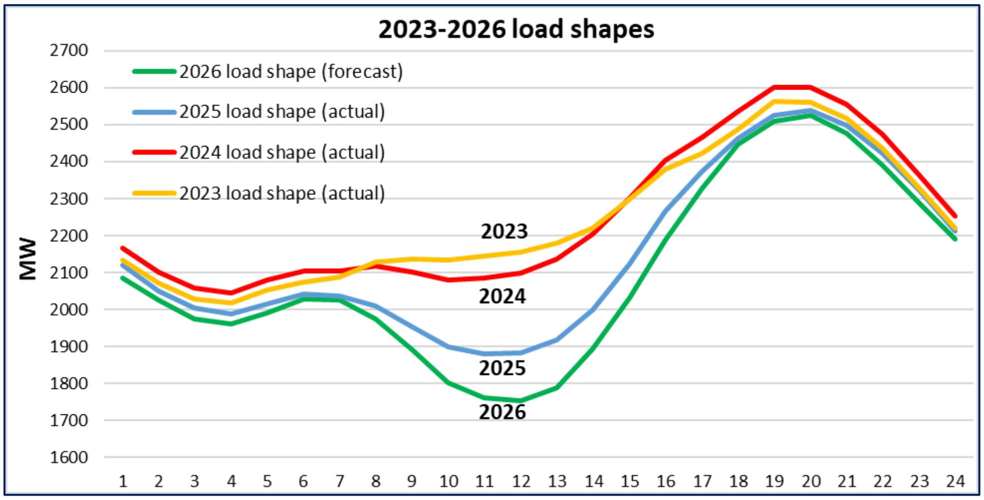
3.1 Electricity Demand

From a demand perspective, the daily pattern of electricity consumption in Puerto Rico is changing. Although the changes may not appear dramatic, even subtle shifts can have important implications on resource adequacy when the overall status of the electricity system is already under stress.

One of the most notable sources of change in electricity demand in Puerto Rico is that households are increasingly installing rooftop solar photovoltaics (PV) systems, some coupled with battery energy storage systems (BESS) —known as Distributed Generation (DG) systems— with the goal of reducing their own monthly electricity bills and increasing the resiliency and reliability of their respective electricity supplies. For LUMA, the net effect of the installation of a growing number of customer-sited DG systems is a reduction in the volume of electricity delivered to customers from the grid during daylight hours. Notwithstanding reduced delivery volumes during daylight hours due to DG system deployment, peak demand for the electricity system during evening hours has maintained similar levels in Puerto Rico. This is the case even though a growing number of residential DG systems in Puerto Rico are being deployed with BESS. This suggests that households are not yet using energy storage to reduce electricity purchases from the grid during evening hours.

Even though rooftop PV systems do reduce aggregate electricity volumes delivered by the electric grid, the addition of PV systems does not materially improve Puerto Rico electricity resource adequacy. This is because resource inadequacies manifest themselves most critically during peak demand hours (between 18:00 (6:00 p.m.) and 22:00 (10:00 p.m.) just after the sun has set, when PV resources cannot supply electricity to help other capacity resources to meet peak demand needs on the system. Figure 3 below illustrates the actual hour-by-hour profile of systemwide electricity demand in Puerto Rico for the last three calendar years (2023 – 2025), and the forecasted hour-by-hour load profile for 2026.

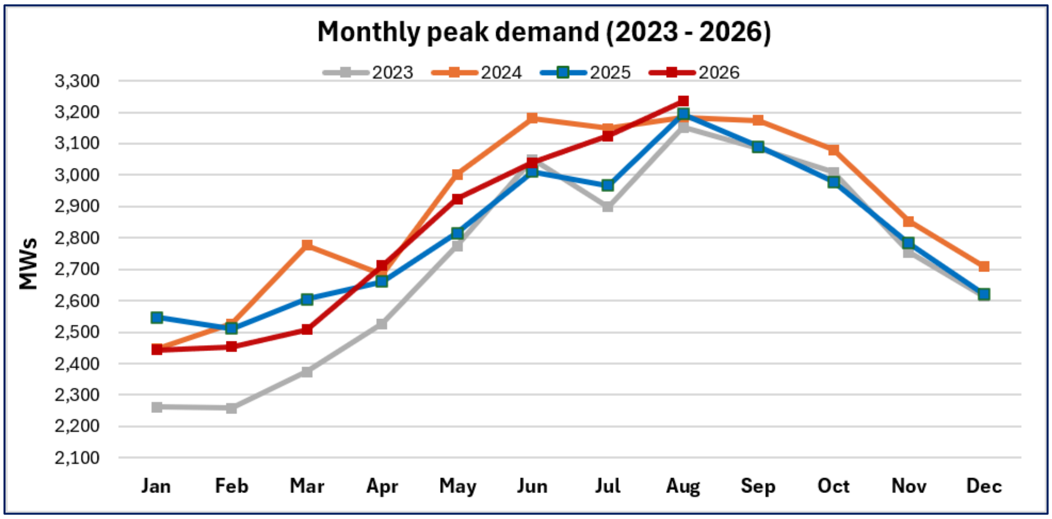
Figure 3: Annual Hour-by-Hour Systemwide Electricity Demand in Puerto Rico



As is the case with most electric utilities in the U.S., peak electricity demands are heavily driven by residential customers when they return home and hence their electric consumption increases.

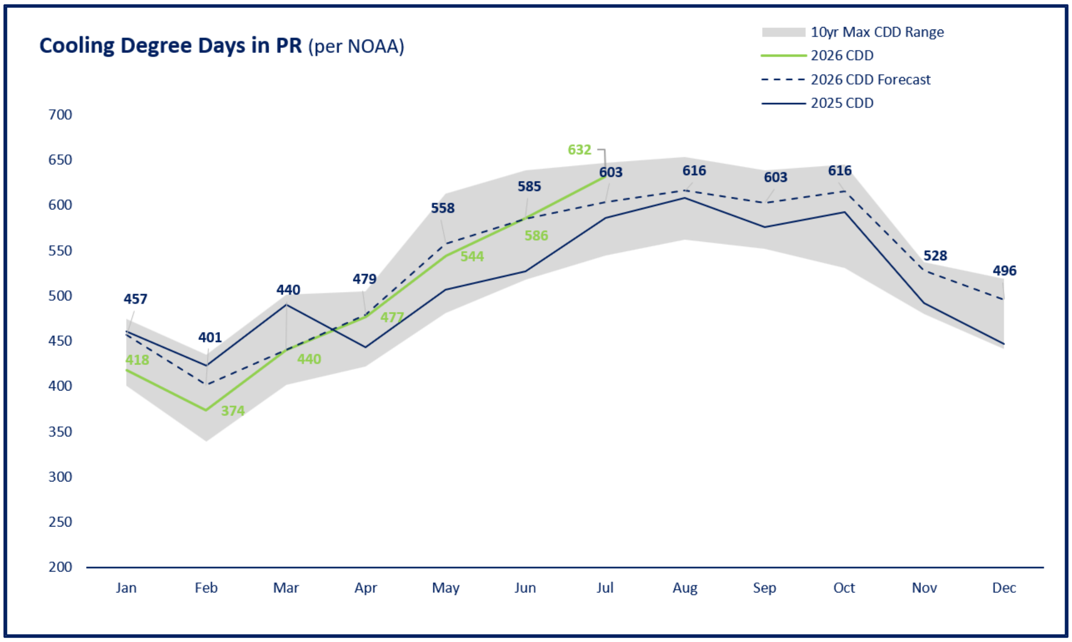
The highest electricity demand of the year in Puerto Rico (i.e., the annual peak load) occurs during the summer, corresponding to days that are especially sunny, hot and humid. Figure 4 below shows the monthly peak demand levels for the last four calendar years (2026 until August), showing that the highest peak demands during months May through October are substantially higher than the peak demands that occur in each of the other months of the year. For 2026, peak demand for the first three months started lower than the previous two years, but since April 2026, peak demand has been increasing by more than 150 MW per month, reaching an approximated peak of 3,234 MW in August (highest peak demand in the last four years). This peak demand increase is directly correlated with the high temperatures Puerto Rico has been experiencing, increasing electric demand.

Figure 4: Monthly Peak Demand Levels on Puerto Rico Electric Grid in the last four years



Compounding matters, Figure 5 shows that last summer in Puerto Rico, as measured in cooling degree days (CDD), was notably lower than historical norms (see blue solid line), resulting in electricity demands below expected levels. The first three months of 2026 have the same tendency as 2025 actual CDD being lower than expected, but from April until July, CDD has been higher than 2025, and in July, CDD was above forecasted levels, almost reaching the highest value in the last 10 years (see green solid line and the gray shaded area).

Figure 5: Monthly Cooling Degree Days in Puerto Rico During Recent Summers



Given that forecasting of electricity demand is a vital function to be performed by every grid operator, LUMA continues to refine its demand forecasting approaches and capabilities on an ongoing basis and consequently updates its forecasts with regularity to better reflect the patterns of electricity consumption currently being observed in Puerto Rico. LUMA's updated forecast estimates summer 2026 peak demand at 3,028 MW, which is slightly below the actual 2025 peak of 3,194 MW.

3.2 Generation Availability

In any electricity system, demand is supplied by a fleet of power generation facilities. Each facility has a "nameplate" rated capacity in MW, which was established when the facility was initially commissioned, based on the then-new equipment that was installed.

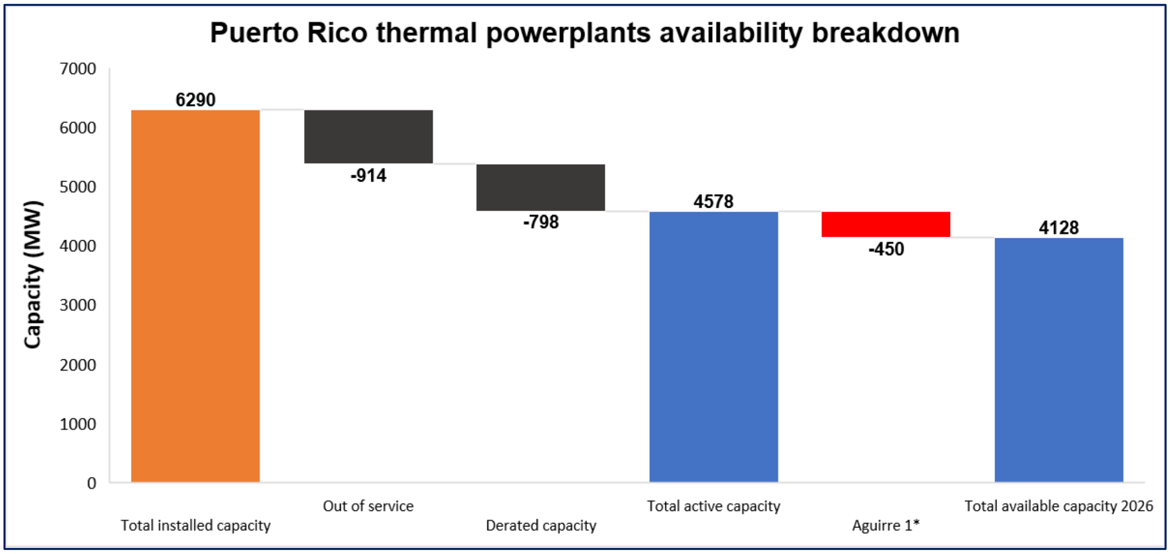
The aggregate nameplate capacity of all the installed power generation resources is 6,563 MW (including thermals, renewables and hydro). Based on this value, relative to the peak demand of 3,028 MW projected for summer 2026, one might be led to believe supplies of electricity generation in Puerto Rico are (or at least should be) readily available. However, the sum of nameplate capacity values from any set of generation facilities significantly overstates the aggregate capacity currently available to deliver electricity from that set of facilities to the electricity grid.

Two sets of considerations must be accounted for when assessing the true available capacity of an electricity system:

- **Dependable capacity:** The nameplate capacity rating of a power plant is based on the theoretical performance of brand-new equipment as measured in the factory. Over time, after years of wear-and-tear, the level of dependable capacity will tend to deteriorate further, such that power generation owners often "derate" the capacity that the facility is stated to be able to produce. For thermal facilities, the same amount of capacity is assumed for each hour of the day. For renewable energy facilities, the hourly dependable capacity varies depending on the availability of wind or sunshine through midday. In summary, for Puerto Rico, the dependable capacity of power generation facilities (mostly thermals) is less than their nameplate capacity.
- **Outages:** As is the case with any machine, any power generation facility will be operational less than 100% of the time. Routine preventative maintenance must periodically be performed and worn, or damaged components must occasionally be replaced. Ideally, maintenance and minor repairs can be undertaken during "planned outages", when the facility is shut down in an orderly fashion at a time when the electricity system can best accommodate its absence until restorative work is complete. In more extreme or severe cases, the facility unexpectedly suffers a major failure and is required to immediately shut down in a "forced outage", whose duration will depend upon the nature of the failure and the ability to obtain necessary resources to restore operational capability. The timing of forced outages is unpredictable, which means that resource adequacy must be evaluated using probabilities and statistical methods, including accounting for possibilities that multiple power generating facilities can become unavailable at the same time due to independent forced outages.

Out of the installed thermal capacity of 6,290 MW, there are approximately 914 MW out of service permanently (or without a time of return) and other 796 MW on capacity derations, leaving an approximate total available capacity of 4,580 MW. Moreover, Aguirre 1 suffered a prolonged forced outage back in February 2025 that will keep the unit out at least the entire 2026 year, subtracting another 450 MW of capacity out of the electric system, driving down total thermal available capacity to 4,128 MW since 2025. Figure 6 below summarizes capacities from total installed capacity to total currently available capacity of thermal facilities.

Figure 6: Puerto Rico Thermal Power Plants Capacity Breakdown

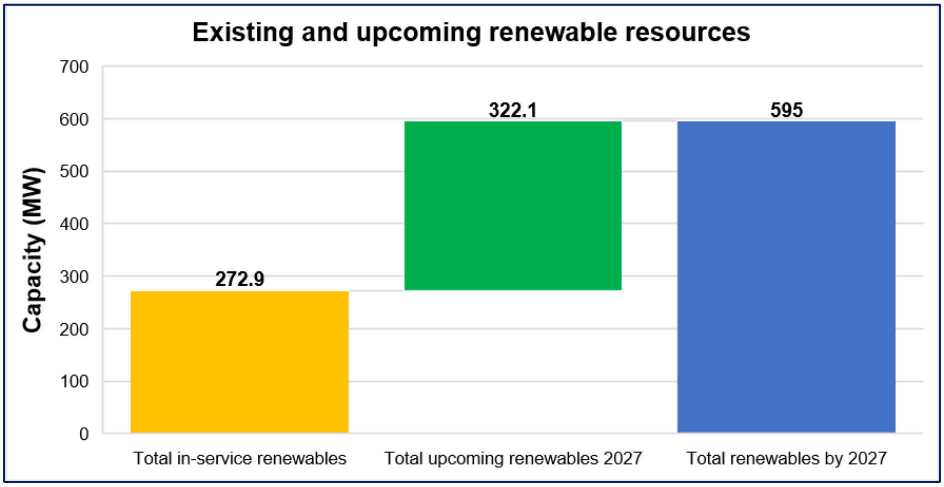


Note: the total 6,290 MW of installed capacity includes 100 MW of hydroelectric generators, while 80 MW of these are considered out of service, leaving to 20 MW of available hydro resources, which are included in the 4,128 MW of total active capacity.

In addition to the thermal resources, there are currently 272.9 MW of utility-scale renewable resources, which are composed of solar, wind and landfill resources. Out of the 272.9 MW, 121 MW are from wind resources, 4.8 MW from landfill and 147.1 MW from solar. The most recent renewable addition was in March 2024 with the re-construction of Punta Lima wind farm (26 MW) after being fully taken down by Hurricane Maria back in 2017.

Earlier this year, four additional solar resources were considered to start commercial operations by the end of 2026 but got delayed for 2027: Ciro One (phase 1), CFE Salinas, CFE Jobos and Yabucoa YFN. Ciro One has been currently in pre-operation mode since December 2025, with expected Commercial Operation Date (COD) by February 2027, integrating 90 MW of renewable energy into the system. These 90 MW from Ciro One are part of the first phase (out of two) of the full project. The other three solar resources are part of Tranche 1 projects, with CODs originally inside the timeframe of this report. These three resources are CFE Salinas (120 MW), CFE Jobos (80 MW) and Yabucoa YFN (32.1 MW), with CODs of 2027. With these four additional renewable resources, the total renewables capacity will increase to 595 MW.

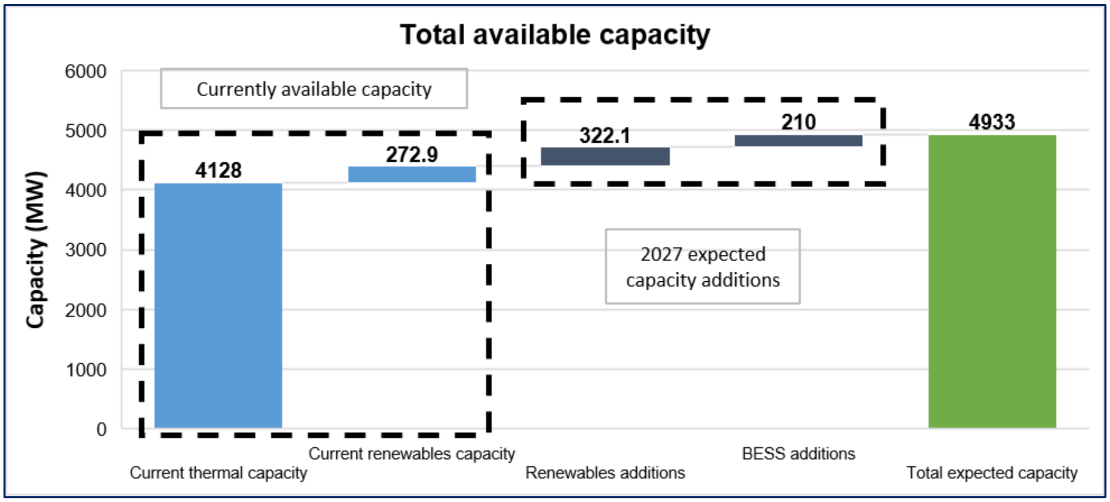
Figure 7: Existing and Upcoming Renewable Resources



CFE Salinas and CFE Jobos are expected to integrate Utility-Scale Battery Energy Storage System (BESS) into the electric system, along with their respective solar components. CFE Salinas will add 100 MW of BESS capacity and CFE Jobos will provide 110 MW of BESS Capacity. As with Ciro One, CFE Salinas BESS is divided into two phases, the first phase consisting of 100 MW that are considered originally by the end of 2026, but similar as the upcoming renewables, CODs got delayed for 2027.

In summary, by the end of October 2026 (end of summer 2026), 4,128 MW of capacity are expected from thermal resources (94%) and 273 MW from renewables (6%), for a total of 4,401 MW capacity. For 2027, 322 MW of additional renewable capacity are expected to integrate into the system, increasing the total capacity to up to 595 MW and the integration of BESS resources of 210 MW, for a total of 4,933 MW capacity.

Figure 8: Current and Expected Capacity Additions by 2027



For every resource adequacy assessment, LUMA undertakes a thorough reassessment of the fossil power plant fleet. For each unit in the Puerto Rico fossil power plant fleet, hourly actual operating data from previous years is reviewed to update assumptions on dependable capacity and forced outage rates.

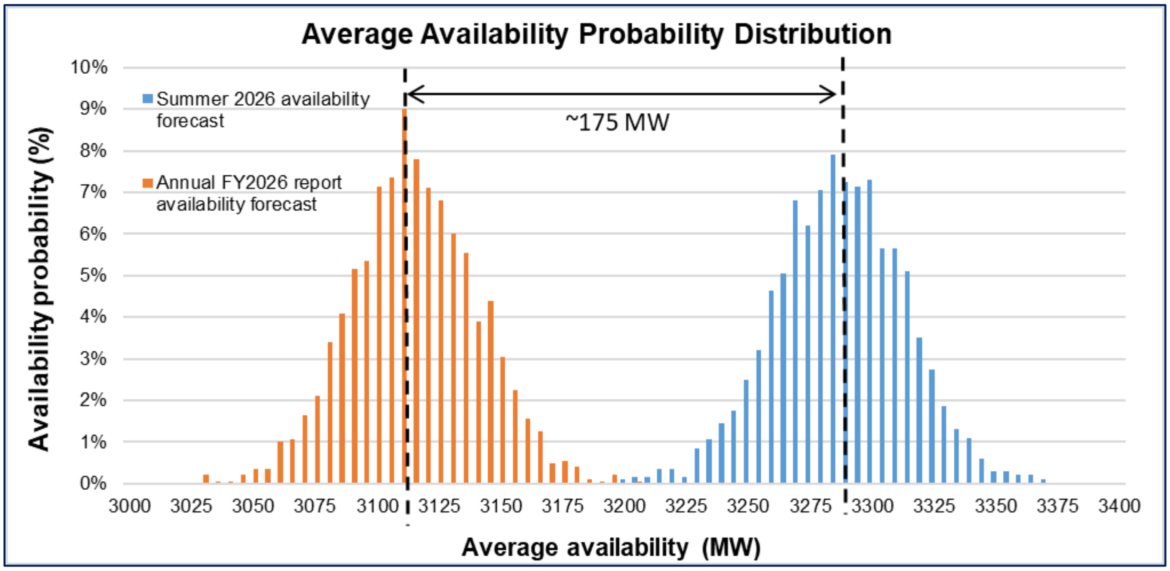
Assumptions about dependable capacity were revised upwards for some units and downwards for others, with the net change across all units being minimal. More substantively, assumptions about forced outage rates were adjusted for all units to reflect actual trends.

A simplistic view of Puerto Rico generation availability based solely on nameplate capacity far exceeding peak demand does not accurately reflect the true ability of supplies to meet demand. This contrast stems from the fact that most of the island's electric generating facilities are not only old but also in poor condition, having suffered from years of underinvestment. Many of these facilities are subject to frequent forced (unplanned) outages, some of which can be lengthy. Even when operational, many of these facilities can dependably operate only at capacity levels substantially below their nameplate ratings.

The expected dependable capacity does not consider any future forced outage that a unit could suffer, meaning that, when modeling analyses are done, considering forced outage rates, available capacity will decrease depending on all the outages the model does. The weighted average forced outage rate assumed for this study is 17%, applying that forced outage rate to the 4,128 MW expected capacity from thermals, availability drops to approximately 3,430 MW. Additionally, during the study period, some additional capacity is assumed to be in planned outages during any point, dropping available capacity further between 3,220 – 3,300 MW on average (as shown below in Figure 9).

The forecasted average amount of available generation capacity in this resource adequacy study is higher than was forecasted in the FY2026 Resource Adequacy Report, mostly due to forced outages decrease and fewer units on maintenance during 2025. As shown in Figure 9, on average for all hours across all simulations, the total generation capacity available to serve Puerto Rico electricity demands has been going up by about 175 MW.

Figure 9: Forecasted Hourly Generation Capacity Availability in Puerto Rico



4.0 Summer 2026 Resource Adequacy

Given that peak electricity demands in Puerto Rico occur during the summer months, generation shortfall load shedding activities will be most evident during this period. Accordingly, this resource adequacy update focuses on how much load shedding activity can be anticipated to occur in Puerto Rico for the summer of 2026.

The two metrics for load shedding activity most presented in this report are: loss of load expectation (LOLE) and loss of load hours (LOLH). LOLE indicates the number of days in which manual load shedding occurs due to generation shortfalls, and LOLH indicates the cumulative number of hours that these load shed events last. Forecasts of summer 2026 generation shortfall load shedding activity, both LOLE and LOLH, represent statistical expectations of resource insufficiencies that would lead LUMA to invoke manual load shedding (MLS) according to LUMA's System Operations Principles. The LOLE and LOLH metrics, which reflect MLS events, the load shed events that correspond to these metrics, do not capture the full extent of generation-driven load shed events experienced by Puerto Rico electricity customers.

Note further that all values of LOLE and LOLH presented in this report for summer 2026 are for the six-month period from May 1, 2026, to October 31, 2026. In contrast, all prior LUMA resource adequacy assessments covered a 12-month period corresponding to the fiscal year (July 1 to June 30). Therefore, it is not appropriate to directly compare the LOLE and LOLH values presented in this report covering six months to LOLE and LOLH values from prior resource adequacy reports spanning 12 months, as the values shown herein would need to be increased to account for the six winter months that were not assessed. It would also not be appropriate to simply double the values presented herein as an adjustment, because LOLE and LOLH levels will be lower in the uninvestigated winter months than in the summer months investigated in this report.

The future cannot be known with certainty. Resource adequacy is the result of many factors, and each factor is itself subject to considerable uncertainty. Because of this, it would be misleading to present any single value of any single measure of resource adequacy and claim it as "the forecast". Instead, a proper assessment of resource adequacy must be probabilistic in nature.

Using modeling techniques and approaches employed by leading electric utilities to conduct a probabilistic analysis of resource adequacy, LUMA's resource adequacy analyses address uncertainty in two ways:

- First, LUMA develops a Base Case along with several sensitivity cases to illuminate how resource adequacy, as measured by estimated load shedding activity (for which LOLE and LOLH are good proxies) stemming from insufficient supply resources, would be affected if certain forces beyond LUMA's control were to arise.
- Second, for each "case", LUMA runs 2,000 iterations of the future in which estimates of LOLE and LOLH are calculated, from which averages and probability distributions of LOLE and LOLH can be presented to illustrate the range of potential load shedding activity that might happen if reality ends up mirroring the conditions associated with the case.

As shown in Figure10, estimated average LOLE ranges from 8 days (base case) to 47 days (10% load increase combined with the prolonged loss of another base load unit.

Although most of the sensitivities analyze one possible scenario, multiple scenarios could combine in actual operations, as for example, the 10% load increase and an additional baseload unit out sensitivity shows.

Figure 10: Projected LOLE for Summer 2026 Across all Cases

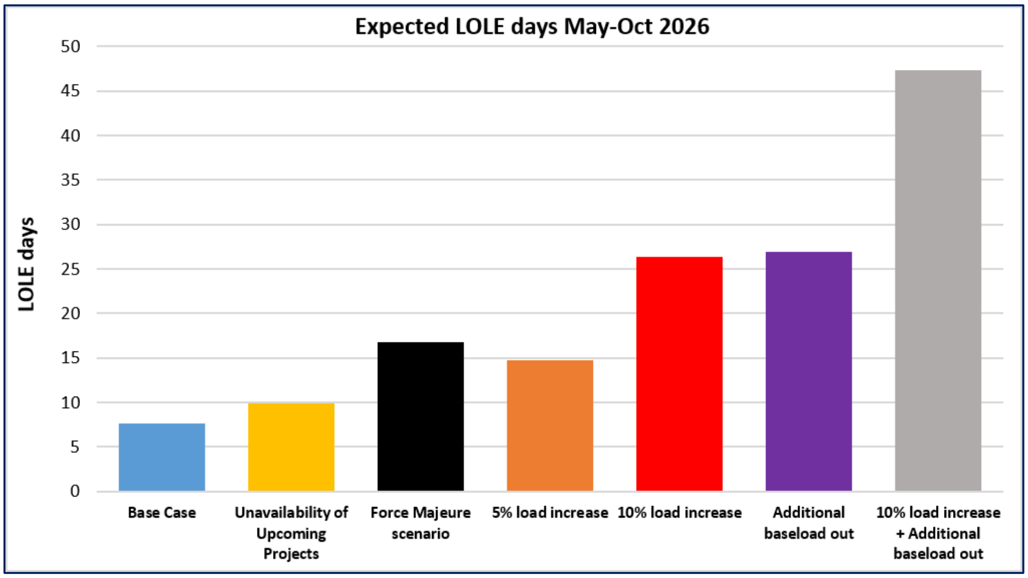
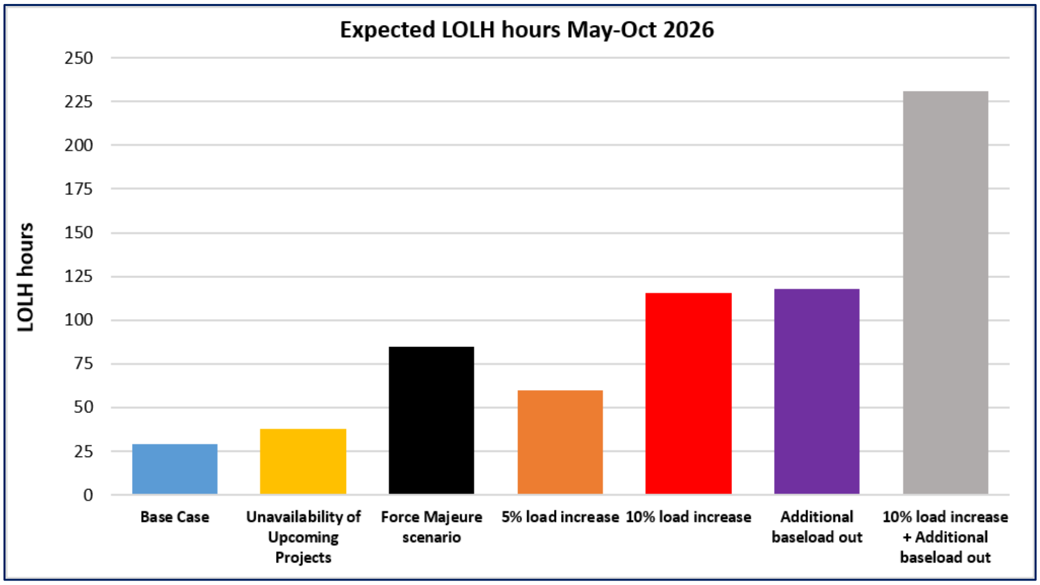


Figure 11: Projected LOLH for Summer 2026 Across all Cases



The following section presents the key findings and conclusions from all cases analyzed for this resource assessment, beginning with the Base Case, followed by a comparison among the sensitivity cases that were investigated.

4.1 Base Case

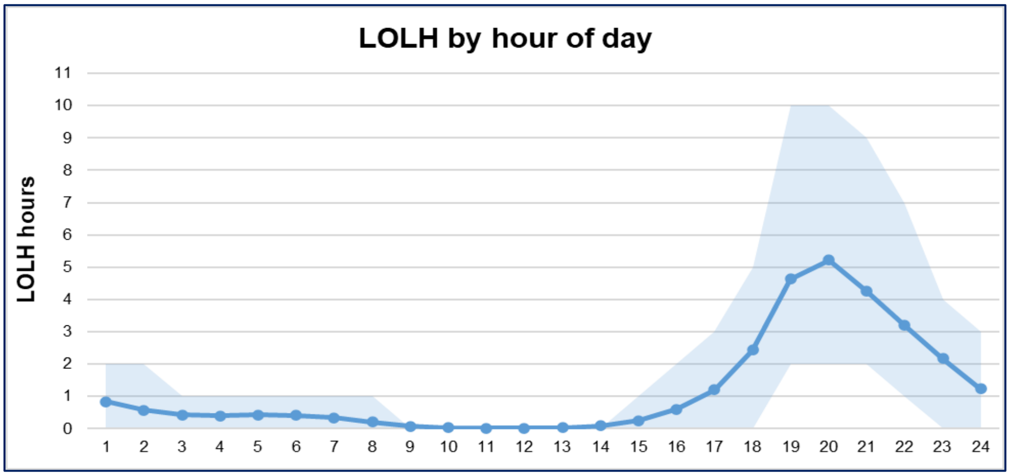
As of the writing of this report, the Base Case presented herein should be considered as the baseline assessment of expected Puerto Rico resource adequacy during the summer of 2026. The Base Case reflects LUMA's modeling representation of the state of the island's electricity generation fleet, along with the further assumptions that systemwide electricity demand materializes at forecasted levels and no other major abnormal events occur. As a result, the Base Case presents the current estimate of the probability distribution and average values for LOLE and LOLH for Puerto Rico in the summer of 2026. As such, the findings from the Base Case warrant detailed discussion here.

As happens in any resource adequacy analyses, results critically depend upon multiple assumptions. Major assumptions associated with the Base Case are discussed in detail in Appendix B herein.

Based on LUMA's experience as system operator for the Puerto Rico electricity grid since June 2021, it is almost always the case that at least one of the legacy PREPA baseload units is out of service at any moment in time due to a major outage, or prolonged maintenance, leading to the assumption that one of the island's large baseload units would be unavailable for the duration of the summer.

Consistent with findings from prior resource adequacy analyses, MLS activity is far more likely to occur during the evening hours, coinciding with the highest demand levels of the day. Figure12 shows forecasted LOLH for the Base Case by hour of the day, peaking between hours 19 and 20. Blue solid line represents the forecasted average LOLH, while blue shaded area represents the hour by hour probability distribution range of LOLH through each simulation iteration, showing a LOLH probability between 2 and 10 at peak hours (19 and 20).

Figure 12: LOLH Forecast for Summer 2026 Base Case by Hour of the Day



On a month-by-month basis over the course of the summer, under conditions reflected by the assumptions of the Base Case, Puerto Rico is likely to be most vulnerable to MLS activity during June. In the month of June, expected LOLE for the Base Case is 3 days and expected LOLH is 12 hours.

It is important to note that the values presented in Figure 13 reflect the average capacity reserves in each hour when averaged across all days of a given month, whereas the resource adequacy analyses presented herein involve modeling reserves on an hour-by-hour basis to more accurately represent the risks of generation shortfalls relative to demand in any hour. Thus, there will be days in any month when available capacity reserves in a given hour will be lower than presented.

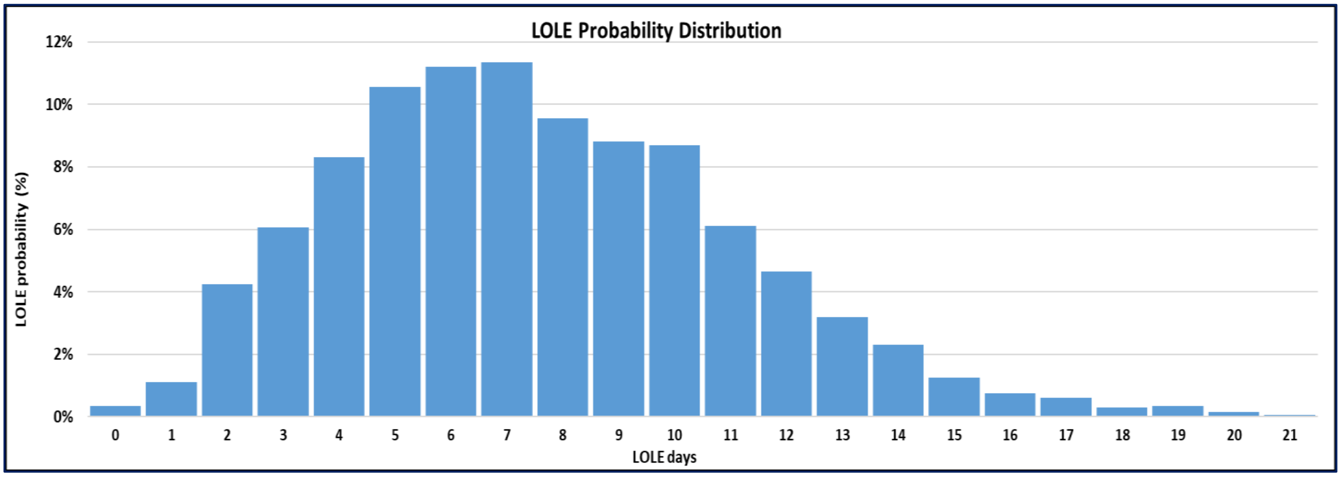
Figure 13: Average Capacity Reserves (MW) by Hour and Month in Base Case

Base Case							
Hour	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Average by hour of day
1	1,124	925	1,117	1,096	1,107	1,101	**1,078**
2	1,165	1,012	1,179	1,166	1,152	1,152	**1,138**
3	1,192	1,071	1,223	1,214	1,182	1,184	**1,178**
4	1,202	1,105	1,244	1,232	1,190	1,188	**1,193**
5	1,196	1,104	1,245	1,220	1,169	1,163	**1,183**
6	1,201	1,118	1,271	1,237	1,173	1,153	**1,192**
7	1,233	1,146	1,292	1,265	1,219	1,181	**1,223**
8	1,287	1,217	1,376	1,359	1,343	1,286	**1,311**
9	1,364	1,315	1,513	1,532	1,524	1,458	**1,451**
10	1,427	1,411	1,619	1,520	1,342	1,257	**1,429**
11	1,450	1,470	1,666	1,591	1,409	1,323	**1,485**
12	1,442	1,480	1,689	1,618	1,397	1,338	**1,494**
13	1,395	1,444	1,663	1,580	1,313	1,265	**1,444**
14	1,313	1,333	1,555	1,438	1,186	1,149	**1,329**
15	1,203	1,135	1,386	1,408	1,373	1,350	**1,309**
16	1,078	920	1,207	1,198	1,183	1,152	**1,123**
17	987	736	1,044	997	1,031	981	**963**
18	921	616	916	823	878	819	**829**
19	828	470	796	681	773	782	**722**
20	813	432	756	668	780	797	**708**
21	840	474	790	721	827	840	**749**
22	898	562	853	790	865	870	**806**
23	974	689	937	889	960	953	**900**
24	1,071	813	1,034	1,007	1,050	1,037	**1,002**
Monthly average	**1,150**	**1,000**	**1,224**	**1,177**	**1,143**	**1,116**	
Average reserves at peak load	**813**	**432**	**756**	**668**	**780**	**797**	

June was anticipated to be the most challenging month for the Puerto Rico electricity grid this summer under the Base Case because forecasted summer peak demand occurs in that month. LUMA's experience is that month-by-month forecasting of resource adequacy is subject to variability because outage schedules are subject to adjustment based on then-prevailing conditions.

The above values for expected LOLE and LOLH under the Base Case do not fully capture the resource adequacy situation in Puerto Rico. It is oversimplistic to gauge resource adequacy by looking only at the singular values of expected LOLE and LOLH. Rather, a more holistic view of resource adequacy is gained by reviewing the probability distribution of LOLE for the Base Case, showing that the number of expected LOLE days for the 2026 summer could fall between 1 and 20 days, in contrast to the actual 16 MLS days in the 2025 summer, and 20 MLS days on average across the past four summers, as shown in Figure14 below.

Figure 14: Probability Distribution for LOLE in Summer 2026 Base Case



4.2 Sensitivity Cases Considering Resources Unavailability

Complementing the Base Case, a series of sensitivity cases were developed to evaluate how resource adequacy could be affected if the generating unit availability performs worse than expected, if additional generation capacity resources were available, if electricity demand ends up being higher than forecasted levels, or if a force majeure event, such as a hurricane, earthquake, or any major system-wide disruption, occurs. Some cases also explore combinations of these conditions.

Sensitivity cases about resources unavailability developed and analyzed:

- No upcoming projects available (upcoming projects do not achieve COD during study period)
- Loss of another baseload unit for the entire summer
- Electric load increased by 5% across all hours
- Electric load increased by 10% across all hours
- Force Majeure scenario: a major event disrupting the entire electric system for an extended period, followed by a sequential recovery. The simulated event date was September 1st.
- Electric load increased by 10% across all hours combined with the loss of another baseload unit for the summer

Detailed statistical results from each sensitivity, along with the Base Case, are provided in Appendix A.

Note that most of the sensitivities were defined to examine in isolation the impact on resource adequacy if only one set of assumptions was varied from the assumptions used in the Base Case. It is possible that, as the summer of 2026 plays out, Puerto Rico could witness a combination of circumstances in which multiple factors will have deviated from the sets of assumptions made in the Base Case. As the last sensitivity shows, if actual power plant availability turns out to be lower than assumed in the Base Case and if actual electricity demand turns out to be higher than assumed in the Base Case, the negative implications on resource adequacy will be more severe than those suggested by the two sensitivity cases that independently investigate the effects of lower power plant availability and higher electricity demand.

Table 1 below summarizes estimated LOLE and LOLH for each of the sensitivities described above, as well as for the Base Case.

Table 1: Results summary of base case and resources unavailable sensitivities

Summer 2026 Sensitivity Cases	Loss of Load Events (# of days)	Loss of Load Hours (# of hours)
Base Case	7.6	29.1
Unavailability of Upcoming Projects	10.0	37.9
Another Baseload Unit out	27.0	118.0
5% Load Increase	14.8	60.1
10% Load Increase	26.4	115.7
Force Majeure Scenario	16.8	84.7
10% load increase & Another Baseload Unit out	47.3	230.7

Sensitivity analyses in this sub section were developed to investigate adverse scenarios for the Puerto Rico electricity grid, show further worsening of resource adequacy relative to the findings from the Base Case. Estimates of LOLE and LOLH for this summer from this set of adverse sensitivity cases varies from an additional 2 to 39 LOLE days, and from 8 to 201 LOLH hours when compared to the Base Case, as shown in Figure 15 and Figure 16 below.

Figure 15: Impact of Adverse Sensitivity Cases on Expected LOLE in Summer 2026

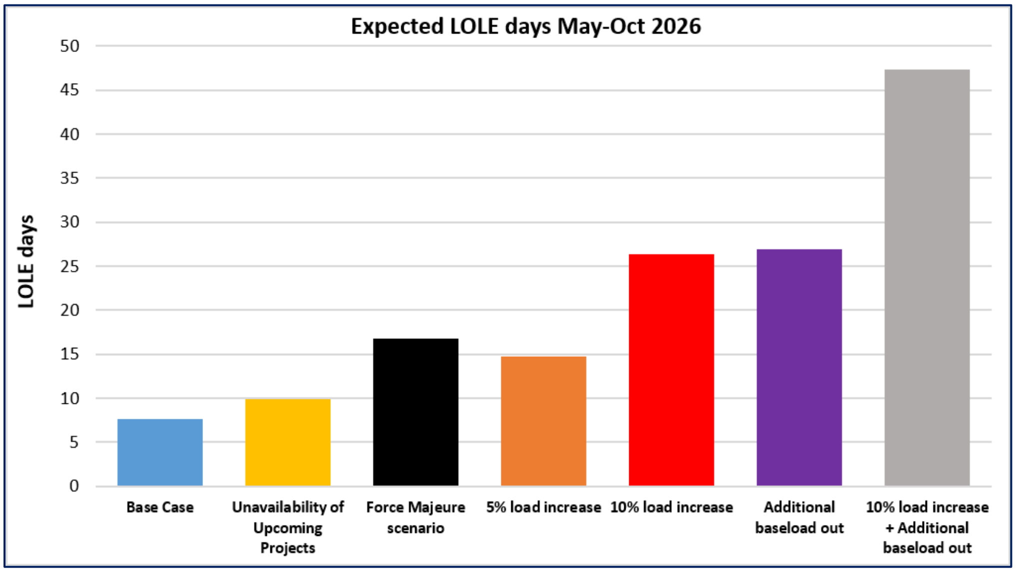
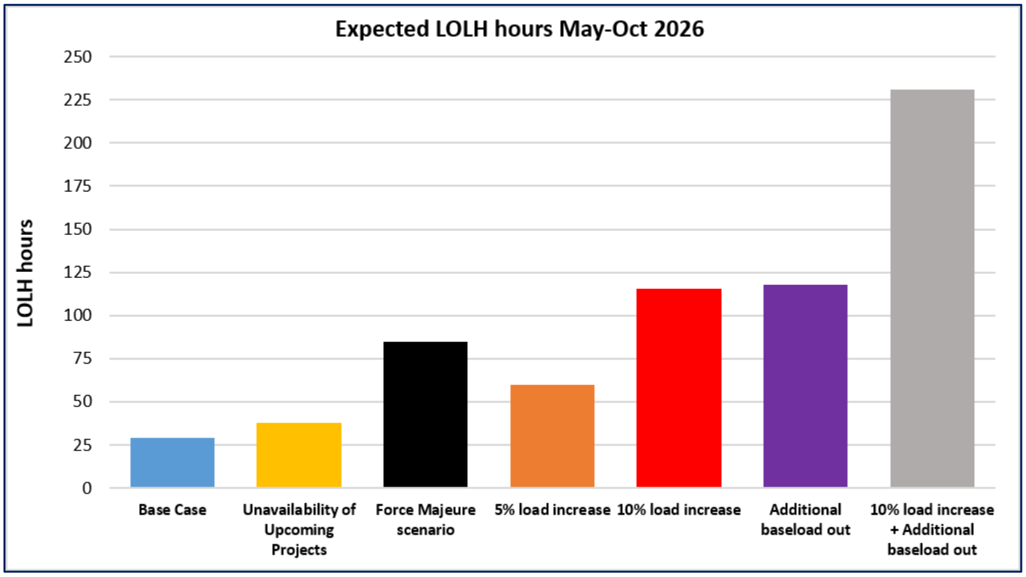


Figure 16: Impact of Adverse Sensitivity Cases on Expected LOLH in Summer 2026



Unavailability of Upcoming Projects:

Comparing the results from the Base Case with the unavailability of upcoming projects sensitivity, it has a LOLE difference of 2 days, and almost 9 LOLH hours. This sensitivity assumes that Ciro One, CFE Salinas and Jobos (both solar and BESS), and Yabucoa YFN projects do not meet their expected COD for the 2026 summer period, resulting in a slight increase in LOLE and LOLH. It is important to note that the CODs of these upcoming projects do not cover the entire study period, meaning that, if these projects were assumed to be available from day 1, the LOLE and LOLH difference will likely be higher.

Force Majeure Scenario

Comparing the differences in expected LOLE and expected LOLH between the Base Case and the Force Majeure Scenario, there is a cumulative increase of approximately 9 days in LOLE and about 56 hours in LOLH. These results are driven by the assumption that a Force Majeure event in Puerto Rico occurs on September 1, resulting in a 50% increase in the forced outage rate applied to the entire system for the remainder of the forecast horizon.

5% and 10% load increase

Increasing the forecasted load by 5% increases projected LOLE by almost double (from 8 to 15 days), while, increasing load by 10%, LOLE increases to 26 days, slightly more than 3 times the forecasted LOLE in the Base Case. See Table 2 below for monthly peak load comparison between Base Case, the 5% and 10% increases, and the actual peak loads until August 2026. Comparing actual peak demands from July and August 2026, they have surpassed the 10% load increase assumption from the sensitivities studied, noting that actual peak demand has significantly surpassed forecasted values, and hence this led to the multiple LOLE events occurring during July and August 2026.

Table 2: Summary of Results for All Summer 2026 Cases

	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26
Base case peak demand (MW)	2,836	3,028	2,720	2,878	2,849	2,706
5% load increase	2,938	3,179	2,856	3,022	2,991	2,841
10% load increase	3,120	3,331	2,992	3,166	3,134	2,977
2026 actual peak demand	2,944	3,069	3,124	3,234	-	-

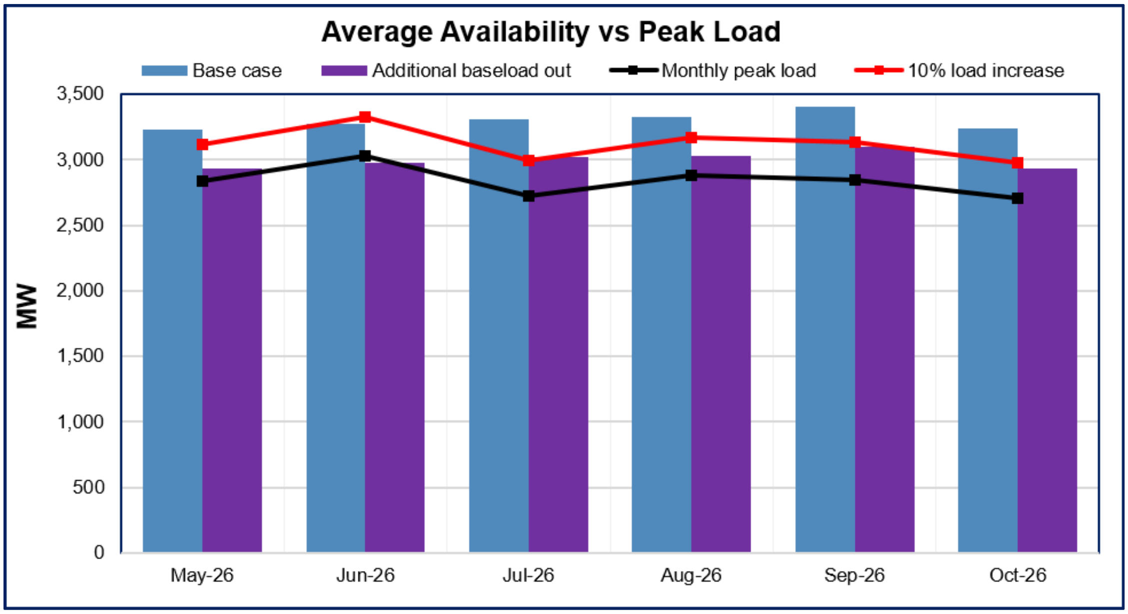
Additional baseload out

Considering the loss of another baseload unit aside from Aguirre 1 (in forced outage), plus San Juan 9 (in planned outage through all summer), Forecasted LOLE for this summer goes up to 27 LOLE days, and 108 LOLH, representing approximately a 250% increase. A scenario like this would quickly increase the risk of prolonged outages on the system and continue deferring other units' maintenance schedules.

10% load increase and Additional baseload out

Combining the loss of another baseload unit and a 10% load increase during the summer period would significantly increase LOLE risk since, if load increases, more resources will be needed to supply all the load and assuming the loss of an additional large generating resource, more resources will be needed. This "worst case scenario" forecasted 47 LOLE days and 230 LOLH for the summer period, resulting in a major resource adequacy deterioration. Figure 17 below compares the electric system monthly average availability between base case and the loss of another baseload, along with the base case load forecast vs 10% load increase.

Figure 17: Average Available Capacity Comparison between the Base Case and the Additional Baseload Unit out Sensitivity



The implication is that reserve capacity deficiencies, and consequently the vulnerability of the need to initiate load shedding, should be anticipated during the summer if another large baseload unit is lost for the entire summer, as is revealed by the considerable decrease on reserves levels, as shown in Figure 18.

Figure 18: Average Capacity Reserves comparison between base case and 10% load increase combined with additional baseload unit out

Base Case

Hour	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Average by hour of day
1	1,124	925	1,117	1,096	1,107	1,101	1,078
2	1,165	1,012	1,179	1,166	1,152	1,152	1,138
3	1,192	1,071	1,223	1,214	1,182	1,184	1,178
4	1,202	1,105	1,244	1,232	1,190	1,188	1,193
5	1,196	1,104	1,245	1,220	1,169	1,163	1,183
6	1,201	1,118	1,271	1,237	1,173	1,153	1,192
7	1,233	1,146	1,292	1,265	1,219	1,181	1,223
8	1,287	1,217	1,376	1,359	1,343	1,286	1,311
9	1,364	1,315	1,513	1,532	1,524	1,458	1,451
10	1,427	1,411	1,619	1,520	1,342	1,257	1,429
11	1,450	1,470	1,666	1,591	1,409	1,323	1,485
12	1,442	1,480	1,689	1,618	1,397	1,338	1,494
13	1,395	1,444	1,663	1,580	1,313	1,265	1,444
14	1,313	1,333	1,555	1,438	1,186	1,149	1,329
15	1,203	1,135	1,386	1,408	1,373	1,350	1,309
16	1,078	920	1,207	1,198	1,183	1,152	1,123
17	987	736	1,044	997	1,031	981	963
18	921	616	916	823	878	819	829
19	828	470	796	681	773	782	722
20	813	432	756	668	780	797	708
21	840	474	790	721	827	840	749
22	898	562	853	790	865	870	806
23	974	689	937	889	960	953	900
24	1,071	813	1,034	1,007	1,050	1,037	1,002
Monthly average	1,150	1,000	1,224	1,177	1,143	1,116	
Average reserves at peak load	813	432	756	668	780	797	

10% load increase + Additional baseload out

Hour	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Average by hour of day
1	763	539	754	719	694	701	695
2	808	632	822	795	743	755	759
3	839	697	871	848	777	791	804
4	850	735	893	868	785	795	821
5	842	731	893	852	762	767	808
6	847	747	920	869	765	755	817
7	880	776	940	899	813	785	849
8	937	853	1,029	995	943	894	942
9	1,017	957	1,173	1,177	1,132	1,073	1,088
10	1,085	1,061	1,285	1,188	994	921	1,089
11	1,109	1,123	1,336	1,263	1,062	990	1,147
12	1,100	1,135	1,361	1,290	1,048	1,005	1,157
13	1,049	1,096	1,333	1,249	957	927	1,102
14	960	976	1,216	1,096	821	802	979
15	843	761	1,033	1,027	936	928	921
16	708	529	842	819	773	755	738
17	613	332	667	608	622	588	572
18	543	207	533	428	465	422	433
19	442	55	404	278	356	383	320
20	425	13	361	265	359	394	303
21	455	56	397	317	400	429	342
22	517	146	466	386	437	456	401
23	600	280	557	492	535	542	501
24	706	415	664	621	631	633	612
Monthly average	789	619	865	806	742	729	
Average reserves at peak load	425	13	361	265	359	394	

4.3 Sensitivity Cases Considering Resource Additions

In addition to unavailable resources sensitivities, three additional sensitivities were analyzed, but considering three different amounts of MWs additions to the system. The three incremental capacities assumed were 200 MW, 400 MW and 800 MW. These capacities were generically chosen, not based on any specific project and/or proponent. Table 3 below summarizes the average LOLE and LOLH results from each capacity addition compared to the Base Case.

Table 3: Results summary of base case and resource additions

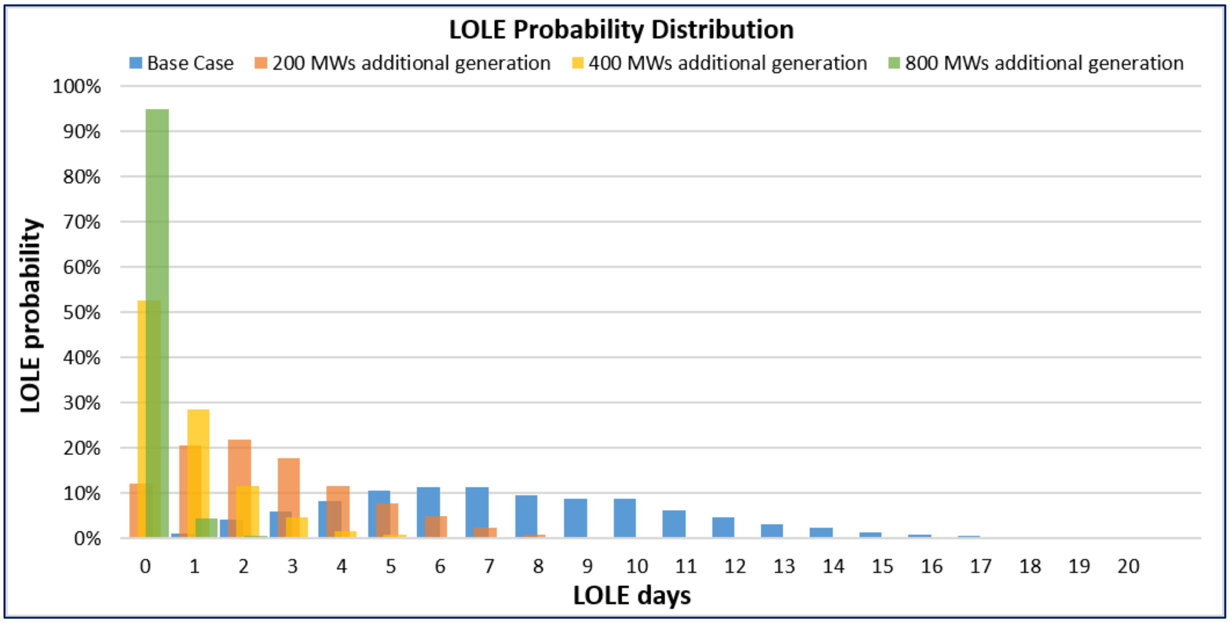
	Loss of Load Events (# of days)	Loss of Load Hours (# of hours)
Base Case	7.6	29.1
Additional 200 MW	2.6	8.9
Additional 400 MW	0.8	2.4
Additional 800 MW	0.1	0.2

Capacity additions analyzed in these sensitivities are classified as firm capacity, meaning that it is reliable and steady capacity that can be used at any hour of the day (excluding planned or forced outages). Firm capacity defines how utilities prepare for high-demand seasons maintaining reliability standards and ensuring that every customer has continuous electricity. Firm capacity varies per resource energy, as each resource has its natural way to generate electricity, such as renewables, storage, thermals, etc.

Figure 19 below shows the LOLE probability distribution between the assumed capacity additions, resulting in progressive improvements until almost 0 LOLE days. It is important to note that these sensitivities, as with the unavailability resources sensitivities, use the assumptions from the Base Case, meaning that, in the event that one or more assumptions deviate from what actually occurs, expected LOLE would also vary. Additionally, these analyses take into consideration that operational units (excluding those in prolonged forced outage, or planned outage) are available, thus not considering that, for example, adding additional capacity to then take out an existing unit for maintenance. If the consideration is to take an existing unit for prolonged maintenance, projected LOLE would be very likely to increase despite generation addition.

As Table 3 above shows, the addition of 800 MW generation could make the electric system from Puerto Rico reach and comply with the US Industry benchmark of having 1 LOLE event each 10 years (or 0.1 LOLE days per year), being consistent with the generation supply deficit range of 700 – 850 MW that was identified in the previous assessments. The absence of new firm capacity integration, plus the absence of Aguirre 1 since February 2025 has maintained this capacity deficit consistently through past assessments. More detail on assumptions of these capacity additions is referenced in Appendix A.

Figure 19: LOLE probability distribution between base case and capacity additions



5.0 Discussion and Conclusions

This Resource Adequacy summer assessment for 2026 demonstrates similar results in resources availability The supply remains structurally fragile, and the summer update confirms that reliability improvements continue to be constrained by real time generation availability and persistent vulnerabilities across the generation fleet.

The Summer 2026 Update Base Case originally projected 8 days of MLS, supported by key assumptions including temporary improvements across several operational parameters, assumed lower forced outage rates for both baseload and peaking units, reduced expected summer load relative to prior years, increased resource availability, fewer planned outages during peak months, the anticipated integration of new solar and battery resources, and an expanded CBES+ demand response program providing relief during reserve margin deterioration..

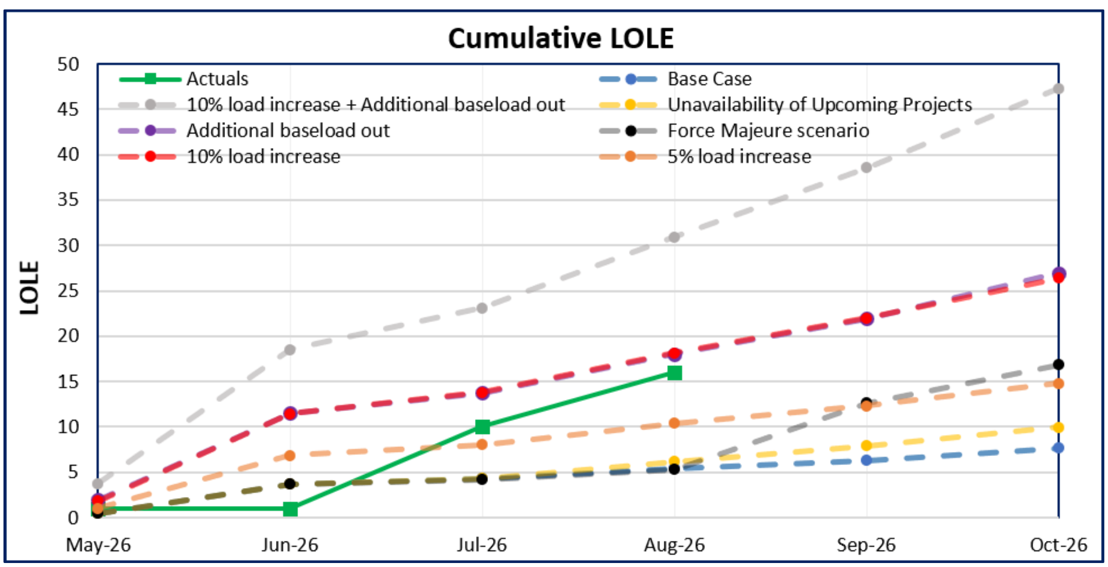
However, in this August 2026 update, the Base Case is now known to have been overly optimistic, having forecasted fewer events than what has happened in actual system performance. While the Base Case projected 8 MLS events for the May–October 2026 period, 16 MLS events have already occurred from May through August alone. Due to the island's persistent generation inadequacy, driven primarily by an increase in power plant outages coinciding with extreme heat conditions that significantly increase electric demand above forecasted levels and reduce reserve margins, MLS events this summer are now expected to surpass the 16 MLS events that occurred in the previous summer. The system has already recorded the same number of MLS events as last year, and if these conditions continue through the remainder of the 2026 summer period, MLS events could approach the levels observed in prior summers, 25 MLS in 2023 and 33 MLS in 2024, reflecting the system's continued vulnerability under stressed operating conditions.

This deviation underscores the value of the sensitivity cases included in the summer update, as they offer a more robust and accurate representation of potential MLS outcomes under varying operating conditions. Consequently, this highlights the importance of not relying exclusively on Base Case forecasts when assessing electric system conditions. Sensitivity analyses remain a critical tool for capturing plausible scenarios that may deviate significantly from initial projections and for informing more resilient operational planning.

The system remains vulnerable, principally due to multiple planned outages that are continuously being delayed or deferred. Rescheduling these planned outages has brought a temporary availability increase, but one adverse effect these deferrals could have is that it puts additional stress on the generating units, increasing the risk of having unexpected outages (including prolonged ones like Aguirre 1 back in 2025), and increasing capacity derations, reaching levels that, if a unit is taken down for maintenance, capacity reserves will likely fall to shortfall levels, worsening and increasing risk of having multiple load shed events; the summer 2026 outlook warns that the loss of an additional baseload unit, or a 10% load increase could increase the expected average LOLE events from 8 to 27 (this can be seen on the additional baseload out sensitivity and the 10% load increase sensitivity individually), and, combining the loss of an additional baseload unit, with a 10% above forecast load increase, average LOLE forecasted rises up to 47 days for the summer period. Recent events in July and August 2026 can be evidence of this system stress from the continuously deferred planned outages that raise the risk of units' failures.

Figure 20 below compares the cumulative monthly forecasted LOLE of each sensitivity with the actual LOLE events that occurred through August 2026, where it can be noted that actual LOLE events (green solid line) already doubled (16 events) from what was forecasted in the Base Case (blue dashed line) (8 events). Actuals are closer to the sensitivity of 10% load above forecast and the loss of another baseload unit individually, situations that have already been experienced especially in July and August 2026.

Figure 20: Actuals LOLE comparison vs forecasted sensitivities (cumulative)



Appendix A:

For the Base Case and for each of the sensitivity cases that were analyzed in this interim resource adequacy assessment, the following sections present key statistical results. Table formats are the same across the cases, facilitating the ability of the reader to select and compare findings across cases to evaluate topics of particular interest.

A.1 Base Case

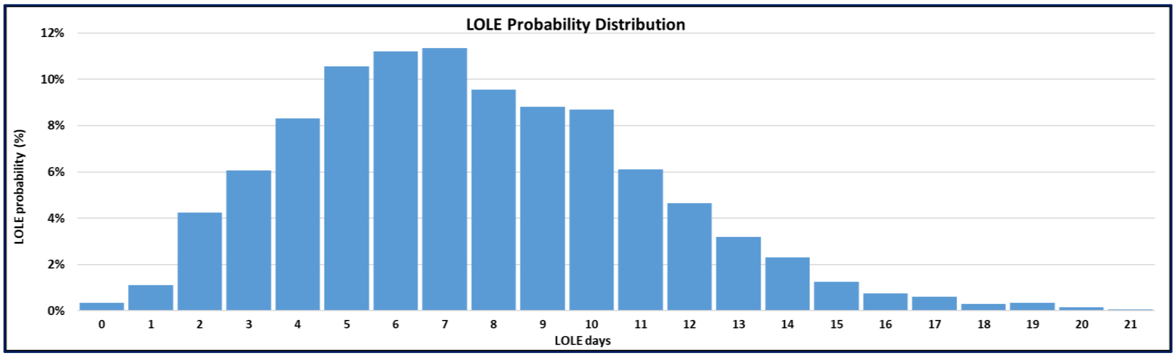
Key statistical results from the Base Case are presented in Table 4 below.

Table 4: Key Statistical Results from Base Case

	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Total or Average
LOLE (days)	0.5	3.3	0.6	1.2	0.8	1.3	**7.6**
LOLH (hours)	1.7	12.1	1.9	4.3	3.4	5.7	**29.1**
Peak demand (MW)	2,836	3,028	2,720	2,878	2,849	2,706	**2,836**
Average total availability (MW)	3,234	3,270	3,313	3,329	3,405	3,235	**3,298**
Average capacity reserves at peak hour (MW)	813	432	756	668	780	797	**708**

Since LOLE results are probabilistic, treating them as a fixed number of forecasted events would not fully capture the results and conclusions to decide if additional resources are needed. Each calculation depends on forced outage rates, variable renewables generation, load forecast variances, and these values could be different on each iteration, leading to different LOLE forecast results and hence developing a probabilistic distribution of possible LOLE outcomes. Instead of focusing on the average LOLE result of 8 days resulting from the Base Case, it is more appropriate to identify LOLE results as between 1 and 20 LOLE days as per the Base Case assumptions, as can be seen in Figure 21.

Figure 21: Base Case LOLE probability distribution



A.2 Sensitivity Cases with Unavailable Resources

Relative to the Base Case, five sensitivity cases were examined to investigate the adverse impact of the unavailability of some resources, load increases, and a combination of these adverse cases.

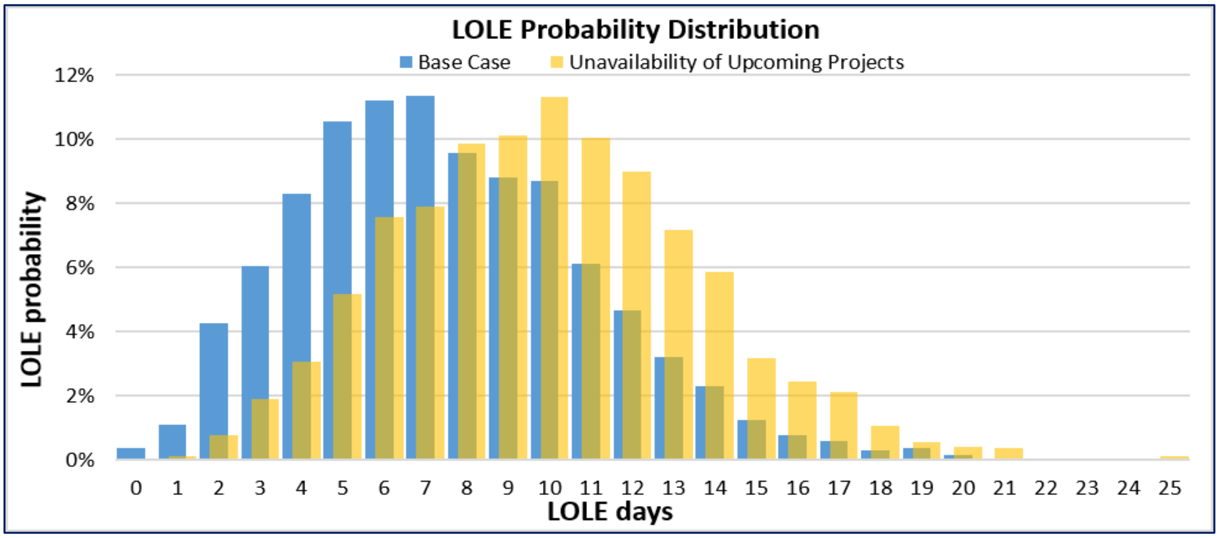
A.2.0 Unavailability of upcoming projects for summer 2026

Key statistical results from the sensitivity case assuming upcoming projects do not meet their expected COD during the study period are presented in Table 5 below.

Table 5: Key Statistical Results from Unavailability of upcoming projects for summer 2026 Sensitivity Case

	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Total or Average
LOLE (days)	0.5	3.3	0.6	1.9	1.8	2.0	**10.0**
LOLH (hours)	2.0	11.7	2.0	6.8	6.9	8.5	**37.9**
Peak demand (MW)	2,836	3,028	2,720	2,878	2,849	2,706	**2,836**
Average total availability (MW)	3233	3271	3287	3204	3193	3036	**3,204**
Average capacity reserves at peak hour (MW)	811	433	753	570	568	596	**622**

Figure 22: LOLE probabilistic results comparison between base case and unavailability of upcoming projects



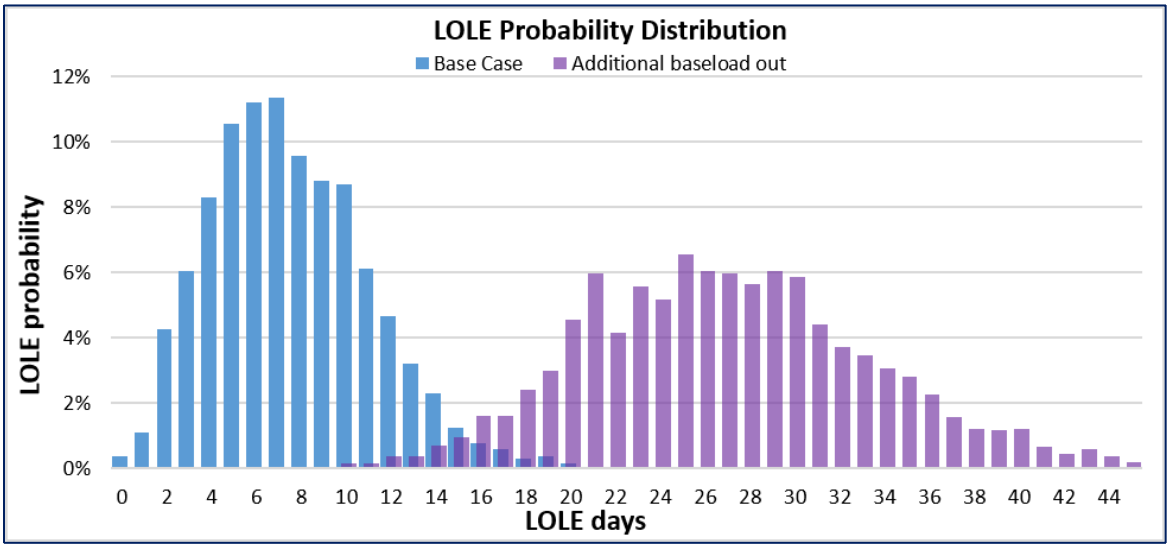
A.2.1 With Another Baseload Unit Unavailable

Key statistical results from the sensitivity case in which another baseload unit is assumed to be unavailable for the entire summer – beyond the two units (Aguirre 1 and another baseload unit) already assumed in the Base Case to be unavailable for the entire summer – are presented in Table 6 below.

Table 6: Key Statistical Results from Sensitivity Case with Another Baseload Unit Unavailable

	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Total or Average
LOLE (days)	1.9	9.6	2.2	4.3	3.9	5.0	**27.0**
LOLH (hours)	8.4	41.4	8.3	18.1	17.8	24.0	**118.0**
Peak demand (MW)	2,836	3,028	2,720	2,878	2,849	2,706	**2,836**
Average total availability (MW)	2,934	2,974	3,017	3,030	3,099	2,931	**2,998**
Average capacity reserves at peak hour (MW)	517	143	463	374	477	495	**412**

Figure 23: LOLE probabilistic results comparison between base case and unavailability of another baseload unavailable



A.2.2 5% Increased load

Key statistical results from the 5% increase in hourly load are presented in Table 7 below.

Table 7: Key Statistical Results from 5% load increase Sensitivity Case

	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Total or Average
LOLE (days)	1.0	5.8	1.2	2.4	1.9	2.5	**14.8**
LOLH (hours)	4.2	23.0	4.1	9.3	8.5	11.0	**60.1**
Peak demand (MW)	2,978	3,179	2,856	3,022	2,991	2,841	**2978**
Average total availability (MW)	3,234	3,270	3,313	3,329	3,405	3,235	**3,298**
Average capacity reserves at peak hour (MW)	694	296	633	538	646	676	**581**

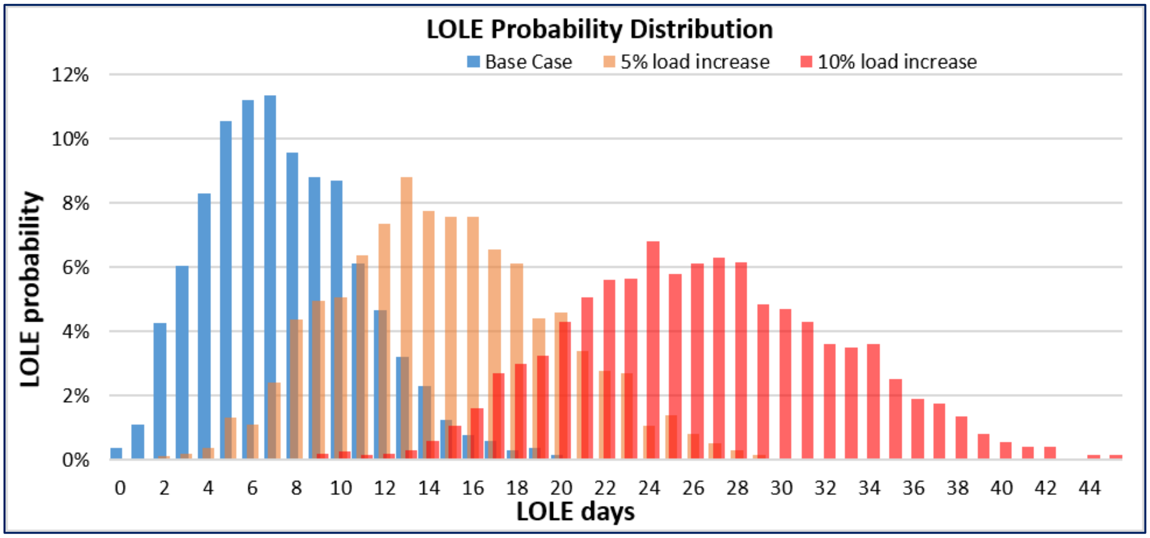
A.2.3 10% Increased load

Key statistical results from the 10% increase in hourly load are presented in Table 8 below.

Table 8: Key Statistical Results from 10% load increase Sensitivity Case

	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Total or Average
LOLE (days)	1.8	9.6	2.3	4.3	3.8	4.4	**26.4**
LOLH (hours)	7.8	41.8	8.6	18.5	17.9	21.0	**115.7**
Peak demand (MW)	3,120	3,331	2,992	3,166	3,134	2,977	**3,120**
Average total availability (MW)	3,234	3,270	3,313	3,329	3,405	3,235	**3,298**
Average capacity reserves at peak hour (MW)	**577**	**159**	**509**	**407**	**512**	**555**	**453**

Figure 24: LOLE probabilistic results comparison between base case and the 5% & 10% load increases



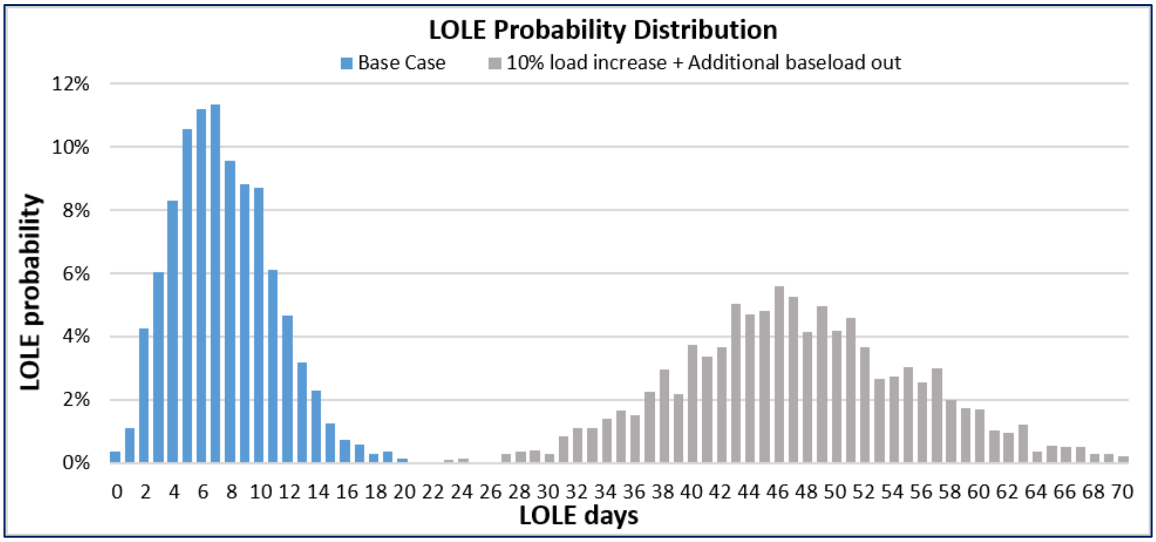
A.2.4 10% Increased load + additional baseload out

Key statistical results from the 10% load increase + additional baseload unit out are presented in Table 9 below.

Table 9: Key Statistical Results from 10% load increase Sensitivity Case

	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Total or Average
LOLE (days)	3.7	14.8	4.6	7.8	7.6	8.8	**47.3**
LOLH (hours)	17.7	72.1	19.1	36.7	39.2	45.8	**230.7**
Peak demand (MW)	3,120	3,331	2,992	3,166	3,134	2,977	**3,120**
Average total availability (MW)	2,934	2,974	3,018	3,030	3,099	2,930	**2,997**
Average capacity reserves at peak hour (MW)	577	159	509	407	512	555	**453**

Figure 25: LOLE probabilistic results comparison between base case and the 10% load increase + additional baseload unit out



A.3 Sensitivity cases with additional generation

Three scenarios of additional capacity were analyzed under Base Case conditions; 200 MW, 400 MW and 800 MW. These capacity additions were added without making other modifications in the assumptions, meaning that it does not contemplate using this additional generation to take out an existing unit for a pending delayed maintenance. This analysis considers all units available besides the ones that are already in prolonged outages (planned or forced). Additionally, if actuals result out closer to one of the sensitivities rather than the base case, expected LOLE from capacity additions could expect an increase relative to the analyzed sensitivities.

Table 10: Key Statistical Results from 200 MW additional capacity

	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Total or Average
LOLE (days)	0.1	1.3	0.2	0.4	0.3	0.4	**2.60**
LOLH (hours)	0.5	4.1	0.5	1.3	1.0	1.5	**8.86**
Peak demand (MW)	2,836	3,028	2,720	2,878	2,849	2,706	**2,836**
Average total availability (MW)	3,422	3,459	3,501	3,450	3,448	3,284	**3,427**
Average capacity reserves at peak hour (MW)	1,000	616	946	858	966	991	**896**

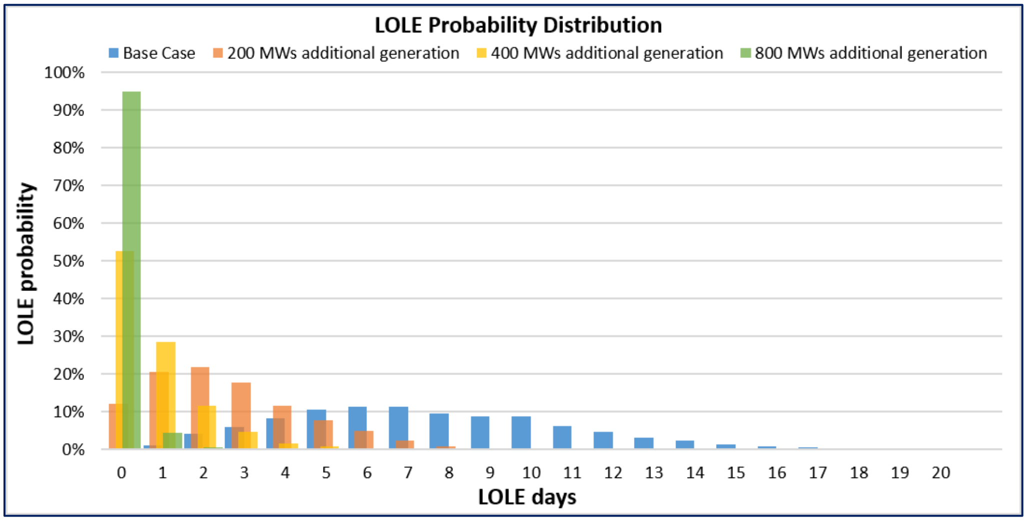
Table 11: Key Statistical Results from 400 MW additional capacity

	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Total or Average
LOLE (days)	0.0	0.4	0.0	0.1	0.1	0.1	**0.8**
LOLH (hours)	0.1	1.4	0.1	0.3	0.2	0.3	**2.4**
Peak demand (MW)	2,836	3,028	2,720	2,878	2,849	2,706	**2,836**
Average total availability (MW)	3,612	3,651	3,692	3,711	3,785	3,621	**3,679**
Average capacity reserves at peak hour (MW)	1,191	807	1,134	1,049	1,162	1,182	**1,087**

Table 12: Key Statistical Results from 800 MW additional capacity

	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Total or Average
LOLE (days)	0.00	0.04	0.00	0.01	0.00	0.01	**0.06**
LOLH (hours)	0.00	0.10	0.00	0.02	0.01	0.02	**0.15**
Peak demand (MW)	2,836	3,028	2,720	2,878	2,849	2,706	**2,836**
Average total availability (MW)	3,988	4,024	4,067	4,083	4,159	3,989	**4,052**
Average capacity reserves at peak hour (MW)	1,569	1,187	1,517	1,426	1,534	1,561	**1,466**

Figure 26: LOLE probabilistic results comparison between base case and additional capacity additions



A.4 Force Majeure Scenario

Lastly, LUMA conducted a sensitivity case that aimed to model the impacts on the Puerto Rico generation fleet as if a major outage event disrupts the electric system (for example: a hurricane hit, an earthquake, or any other major event) being September 1st, 2026, as the "Force Majeure" date. The assumptions and methodology of this sensitivity analysis mirrored the "Force Majeure Scenario" presented in the FY2026 Resource Adequacy Report. Because this case differs from the Base Case only in the months of September and October, all results presented below are different only after the "Event" date.

Key statistical results from the Force Majeure Scenario case are presented in Table 13 below.

Table 13: Key Statistical Results from Force Majeure Scenario Sensitivity Case

	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Total or Average
LOLE (days)	0.4	3.2	0.6	1.1	7.3	4.1	**16.8**
LOLH (hours)	1.7	11.7	1.9	3.9	43.9	21.3	**84.7**
Peak demand (MW)	2,836	3,028	2,720	2,878	2,564	2,706	**2,836**
Average total availability (MW)	3,233	3,268	3,312	3,332	2,465	2,986	**3,099**
Average capacity reserves at peak hour (MW)	815	429	754	670	459	555	**614**

Appendix B: Major Assumptions

To conclude this interim resource adequacy assessment, this section documents the critical assumptions that most heavily affect the results presented herein. As noted earlier in this report, there are two sets of assumptions that are vital to consider: supply-related assumptions and demand-related assumptions. Each of these will be discussed in turn below.

B.1 Thermal Generation Fleet Performance

The most important set of assumptions affecting these resource adequacy results yields the amount of capacity that can be anticipated at a moment in time to be available from Puerto Rico's thermal power generation asset base. Note that more than 90% of total capacity on the island is thermal generation, with most of the remainder being PV that can contribute only negligibly to resource adequacy because of inability to supply electricity during peak demand hours occurring after sunset.

Generating capacity actually able to serve electricity load is determined by dependable capacity, which is less than nameplate rated capacity for most of the Puerto Rico fossil generation fleet (especially so for the PREPA legacy units) and outages, which in turn are comprised of planned outages already scheduled in order to make repairs and forced outages, which, because they are random and unexpected, cannot be accurately modeled deterministically but must instead be modeled probabilistically.

For each thermal generation facility in Puerto Rico, Table 14 presents the dependable capacity and forced outage rate assumptions for each fossil power plant unit that were used in this resource adequacy assessment.

Table 14: Assumptions on Dependable Capacity and Forced Outage Rate for thermal Power Plants

Generator Name	Start of Operations	Nameplate Capacity (MW)	2026 Dependable Capacity (MW)	2025 Dependable Capacity (MW)	2026 Forced Outage Rate (%)	2025 Forced Outage Rate (%)
AES 1	2002	227	227	227	7.5%	10%
AES 2	2002	227	227	227	10%	15%
Aguirre Steam 1[1]	1971	450	0	0	25%	25%
Aguirre Steam 2	1971	450	330	340	20%	20%
Costa Sur 5	1972	410	380	330	15%	20%
Costa Sur 6	1973	410	350	350	15%	15%
EcoEléctrica	1999	545	545	545	2%	3%
Palo Seco 3	1968	216	170	170	10%	15%
Palo Seco 4	1968	216	170	180	20%	25%
San Juan 7	1965	100	90	90	50%	45%
San Juan 9	1968	100	90	90	5%	5%
San Juan Combined Cycle 5	2008	220	210	210	5% CT[3] & 10% STG[4]	5% CT[3] & 15% STG[4]
San Juan Combined Cycle 6	2008	220	210	210	15% CT[3] & 25% STG[4]	10% CT[3] & 20% STG[4]
Aguirre Combined Cycle 1	1977	296	130	130	25%	50%
Aguirre Combined Cycle 2	1977	296	130	130	25%	60%
Cambalache 2	1998	82.5	78	78	5%	10%
Cambalache 3	1998	82.5	78	78	15%	15%
Mayagüez 1	2009	55	25	50	15%	30%
Mayagüez 2	2009	55	50	50	15%	30%
Mayagüez 3	2009	55	25	25	15%	30%
Mayagüez 4	2009	55	25	25	15%	30%
3 Palo Seco Mobile Pack	2021	3 x 27	81	81	25%	40%
7 Gas Turbines (Peakers)[2]	1972	18 x 21	147	147	40%	40%
4 TM Gens (Palo Seco)	2023	2 x 20 + 2 x 25	90	90	20%	12.5%
10 TM Gens (San Juan)	2023	10 x 25	250	250	25%	20%
Total capacity / weighted forced outage	**-**	**5,336**	**4,108**	**4,103**	**17%**	**22%**

Notes from Table 14:

1. The Base Case considers Aguirre 1 to be out of service for the entire analysis period. Aguirre 1 suffered a major failure in February 2025 that will have the unit out for approximately 2 years.

2. Out of a total of 18 gas turbines of 21 MW capacity, only 7 are considered operational.

3. CT = Combustion Turbine

4. STG = Steam Turbine Generator

As can be seen in Table 14, the sum of 2026 assumed dependable capacity (4,108 MW) of the thermal generation fleet is substantially less than the sum of installed nameplate capacity (6,290 MW), reflecting the degraded state of many of the facilities. Note that this table above does not include units permanently out of service

With respect to the assumptions on forced outage rates, the net effect of the unit-by-unit performance, when weighted by each unit's share of total generation capacity, is that the average forced outage rate of the average baseload unit is now 14% (down from 16% assumed in the FY2026 Resource Adequacy Report), and the average forced outage rate of the average peaker is now 23% (down from 36%), combining for a total system weighted forced outage rate of 17%. By comparison, according to NERC's 2023 State of Reliability Technical Assessment, the comparable weighted-average forced outage rate for the U.S. fossil power generation fleet was 8.5% in 2022.

The assumptions contained in Table 14 were developed after a thorough review of actual output and downtime from each of the units during the previous years and reflect LUMA's best judgment of how to most accurately model the ability of the Puerto Rico generation fleet to supply electricity at any moment in time. During this review, it was found a forced outage rate increase in a few units, which includes San Juan 7, San Juan 6 Combined Cycle and all the most recent system acquisition TM units (Palo Seco and San Juan). Units including Aguirre 2, Costa Sur 6, San Juan 9, San Juan 5 Steam, Cambalache 3 and the 21 MW gas turbines maintained unchanged forced outage rates. The other units had a decrease in the assumed forced outage rate due to recent forced outage reduction in 2025. In addition to the assumptions on forced outage rates listed in the above table, note that LUMA assumes any forced outages to have a duration of 40 hours, after which time the unit will be returned to service.

Because power plant outages can be either planned or unplanned (i.e., forced), resource adequacy modeling also relies upon assumptions about planned outages of the power plant fleet. This summer 2026 resource adequacy assessment assumed the outage schedule reviewed by LUMA System Operations in February 2026, which is summarized in Table 15. This table includes planned outages and prolonged forced outages that have a known date of return.

Table 15: Outage Schedule Assumptions

Unit	Outage Start Date	Outage End Date
AES 1	10/3/2026	10/30/2026
AES 2	2/1/2026	3/3/2026
Aguirre 1	2/14/2025	12/23/2026
Aguirre 2	12/12/2026	2/20/2027
Costa Sur 5	11/1/2026	12/24/2026
Costa Sur 6	-	-
EcoEléctrica CT1	11/7/2026	11/10/2026
EcoEléctrica CT2	10/24/2026	11/18/2026
EcoEléctrica Steam	11/7/2026	11/10/2026
Palo Seco 3	1/15/2026	4/30/2026
Palo Seco 4	1/9/2027	3/13/2027
San Juan 5 CT	-	-
San Juan 5 Steam	-	-
San Juan 6 CT	12/6/2025	4/15/2026
San Juan 6 Steam	6/12/2024	4/15/2026
San Juan 7	10/2/2024	5/15/2026
San Juan 9	4/15/2026	10/15/2026
Cambalache 2	8/1/2026	10/5/2026
Cambalache 3	5/19/2025	3/17/2026
Mayagüez 1	2/2/2025	6/30/2026
Mayagüez 2	-	4/30/2026
Mayagüez 3	-	-
Mayagüez 4	-	-

This planned outage schedule shows that a few of Puerto Rico's most important power plant units— AES 1, San Juan 7, and San Juan 9— are expected to be on maintenance during some portion of the May through October 2026 time horizon analyzed in this resource adequacy assessment. Of these, San Juan 7 and San Juan CC 6 are in extended outages, and LUMA's experience has shown that delays in return to service after lengthy outages are commonplace. Furthermore, San Juan CC 6 and Palo Seco 3 are assumed to return to service just before the beginning of this resource adequacy assessment time window, meaning that any significant delay in their return to service would only serve to worsen the results presented herein.

B.2 Future Upcoming Projects

As part of the assumptions through all sensitivities, below are the projects that were expected to be synchronized this summer (between July and August). It is important to note that the Commercial Operation Dates (COD) considered are based on the information received as of February 2026. These CODs are subject to change. Table 16 shows the facility, capacity, capacity factor and COD of the expected solar projects for this summer, while Table 17 shows the facility, capacity, storage duration, storage capacity and COD of the expected BESS projects for this summer.

Table 16: Future Upcoming Renewables Projects Considered

Facility	Capacity (MW)	COD in February 2026	COD in August 2026
Ciro One (Phase 1)	90	July 2026	February 2027
CFE Salinas Solar	120	August 2026	March 2027
Yabucoa YFN	32.1	August 2026	February 2027
CFE Jobos	80	September 2026	March 2027

Table 17: Future Upcoming BESS Projects Considered

Facility	Capacity (MW)	Storage Duration hours	Storage Capacity (MWh)	COD in February 2026	COD in August 2026
CFE Salinas (Phase 1)	100	4	400	August 2026	March 2027
CFE Jobos	110	4	440	September 2026	March 2027

B.3 Demand Response Programs (CBES+)

The Customer Battery Energy Sharing (CBES) program is an emergency demand response (DR) initiative in Puerto Rico designed to improve resource adequacy during generation shortfalls. Unlike traditional DR that incentivizes customers to reduce consumption, CBES operates by aggregating energy stored in residential battery systems (BESS) and discharging it back into the grid. For this resource adequacy study, the program was modeled as "additional capacity" resource available at peak hours when reserves are expected to be lower than 200 MW for peak hours. The modeling assumptions consider the program to be available for a maximum of 4 hours within any rolling 24-hour period. Table 18 illustrates the specific assumptions for CBES. Values assumed in table 18 were dated back from February were an approximate total daily of 168 MegaWatt-hour (MWh) were available. Recently in summer 2026, this program has been increasing its capacity up to approximately 400 MWh.

Table 18: Demand Response Program Considered

Program	Capacity (MW)	Duration hours	Daily total maximum energy apported (MWh)
CBES+	42.1	4	168.4

B.4 Electricity Demand Forecast

The final important set of assumptions that significantly affect a resource adequacy assessment is the systemwide electricity demand forecast.

For its resource adequacy modeling, LUMA takes its most recent electricity demand forecast, which estimates future monthly peak demand and monthly electricity volumes from the Puerto Rico bulk power system, and develops an hourly electricity demand forecast wherein the sum of hourly demands equals the monthly volumetric forecast. The allocation of monthly volumes to the hourly level required for resource adequacy modeling is accomplished by developing an average daily load shape such that the ratios of hourly demands over a month to the monthly peak demand are consistent with hour-by-hour systemwide demand patterns observed last summer.

The monthly peak demands and electricity volumes employed for the Base Case from LUMA's most recent forecast are presented in Table 19.

Table 19: Forecasted Monthly Peak Demands and Electricity Volumes

	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26
Monthly Volumes (GWh)	1,560.5	1,646.3	1,564.7	1,598.8	1,613.5	1,560.9
Peak Demand (MW)	2,836	3,028	2,720	2,878	2,849	2,706
Peak Demand 5% increased (MW)	2,978	3,179	2,856	3,022	2,991	2,841
Peak Demand 10% increased (MW)	3,120	3,331	2,992	3,166	3,134	2,977

As can be seen from the above table, peak demand for summer 2026 in the Base Case is projected to reach 3,028 MW. Since actual peak demand in 2025 was 3,194 MW, LUMA is therefore forecasting a peak demand decrease for this year.

Then, for the 5% and 10% load increase sensitivity cases, the hourly electricity demand assumption from the Base Case was adjusted across all hours of the study period. This adjustment factor was developed based on the approximate magnitude by which prior LUMA forecasts of summer electricity consumption have occasionally under-forecasted actual electricity consumption and peak demand.

The above discussion focuses heavily on peak demand, which clearly is the most critical demand-side determinant of overall resource adequacy. However, the importance of assumptions about the monthly volumes of electricity demand should not be underestimated, particularly given the extent of the resource deficiency of the Puerto Rico electricity system. Because forced outages are unpredictable and hence can occur at any time, they can trigger generation shortfalls and load shedding in Puerto Rico during off-peak hours as well as peak hours.