2025 Integrated Resource Plan (2025 IRP)

NEPR-AP-2023-004

Executive Summary

LUMA is committed to transforming Puerto Rico's energy system into one that is more reliable, resilient, cleaner, affordable, and sustainable for all its 1.5 million customers. Since assuming operations over Puerto Rico's Transmission and Distribution System ("T&D System"), LUMA has focused on critical priorities, consistent with the System Remediation Plan ("SRP") and approved budgets, to make real and sustainable progress toward achieving a better electric service for our customers. To date, LUMA has improved grid resiliency by installing more than 35,500 new storm-resilient poles, clearing hazardous vegetation from more than 6,491 miles of powerlines, and installing more than 10,418 grid automation devices to reduce outage impacts. It has also replaced more than 180,800 streetlights to improve safety. These actions have had a positive, meaningful benefit the service reliability experienced by customers. Importantly, LUMA has implemented this work while staying on budget and keeping its promise not to raise rates in the first three years as operator.

As all Puerto Ricans are aware, the Island's electric grid continues to face significant challenges due to the decades of neglect of the former operator, PREPA, including aging infrastructure, vulnerability to extreme weather events, and limited generation capacity. The 2025 Integrated Resource Plan (IRP) provides a strategic framework to address these challenges and identify actionable, data-driven pathways toward a modernized and more dependable system, delivering what matters most to our customers: affordable, reliable, resilient, and cleaner electric service.

Puerto Rico's 2025 Integrated Resource Plan (IRP)

The 2025 IRP represents a critical milestone in Puerto Rico's ongoing journey toward a more sustainable, resilient, and cost-effective energy future. Developed under Regulation 9021 and led by LUMA Energy, the 2025 IRP serves as a comprehensive, data-driven roadmap designed to guide the Island's energy development over the next two decades toward a system that can reliably and sustainably meet the energy demand and capacity needs of the island, while aligning with public policy objectives and regulatory mandates.

The 2025 IRP ensures that Puerto Rico's evolving electric system meets both current and future needs. This and subsequent IRPs include a five-year action plan that will allow the Energy Bureau and the local government to determine which energy resource projects to implement in the near and long term. While it evaluates energy needs throughout two decades, LUMA is mandated to update the IRP every three years to adjust it to the period in which the analysis is being conducted.

It's important to remember that LUMA's role is to be an objective planner and author of the IRP, using sophisticated analyses and modeling to recommend the optimal plan for Puerto Rico, and to act as an advisor to the Energy Bureau and key stakeholders. As the operator of Puerto Rico's T&D system, LUMA does not hold primary responsibility for the implementation of future energy resource projects, nor does it own or operate generation assets, but plays a pivotal role in enabling the interconnection of energy resources, and is responsible for preparing, presenting, and defending both current and future IRPs.

The 2025 IRP is guided by six principal objectives:

1. Prioritizing customer affordability by reducing nominal energy supply costs.
2. Achieving compliance with the Renewable Portfolio Standard (RPS).

3. Building a cleaner energy future by reducing carbon emissions.
4. Optimizing technology diversity.
5. Enabling decentralized generation.
6. Reducing the impact of outages for our customers by achieving industry-standard reliability, as measured by the Loss of Load Expectation (LOLE).

A Collaborative Effort

Since 2022, LUMA has been committed to maintaining transparency and communication with the Energy Bureau and stakeholders to develop a realistic and pragmatic IRP that adheres to industry standards and reflects accurate, comprehensive data and the future energy needs and priorities of LUMA's customers as Puerto Rico moves toward achieving a more reliable, more resilient, and cleaner energy system. Notably, in developing the 2025 IRP, LUMA prioritized stakeholder engagement through the Solutions for the Energy Transformation of Puerto Rico (SETPR) initiative, a collaborative process that was designed to engage with a broad variety of customers and stakeholders and gain their input regarding Puerto Rico's energy future to help ensure that the final 2025 IRP incorporates broad stakeholder priorities. In total, this process included 30 public meetings attended by 263 stakeholders.

In addition to the critical public meetings held across the island, the IRP development process required extensive data collection, sophisticated modeling, and in-depth risk analysis. With the rapid growth of inverter-based renewable resources such as solar and wind energy, and the increasing role of customer-controlled assets like demand response (DR) and distributed solar (DPV), , LUMA incorporated probabilistic methods and risk metrics to evaluate variability and flexibility within the system. Although it involves economic studies in its forecasts, financial analyses are outside the 2025 IPR's scope. Therefore, discussions on identifying funding for new generation technologies are not covered within this Report.

Preferred Resource Plan – Balanced, Cost-Effective

Planning to meet Puerto Rico's current and future energy needs remains particularly complex. The Island's grid operates with outdated assets, limited generation, and infrastructure that has exceeded its expected service life due to the decades of neglect and insufficient maintenance it suffered under the previous grid operator, as well as the ongoing, significant underfunding of system operations. To address these realities, the 2025 IRP evaluated 12 primary scenarios, each incorporating different assumptions related to future load growth, fuel costs, capital expenditures, and technology availability. Based on the results of this comprehensive modeling effort, Resource Plan Hybrid A was selected as the Preferred Resource Plan (PRP).

The selected PRP represents the most balanced and cost-effective strategy to meet Puerto Rico's long-term electricity requirements while supporting customer affordability and policy objectives, including the goal of transitioning to 100 percent renewable energy by 2050. The PRP will benefit Puerto Rico's 1.5 million electric customers by integrating a diverse array of cost-effective generation sources to reduce generation outages while increasing the contributions from utility scale solar (UPV), distributed solar (DPV), and renewable biodiesel. The PRP includes the addition of 4,364 MW of new capacity by 2030 that is shown in Table 1, with 90% of this capacity coming from projects for generation and battery additions that are already in progress with preliminary approvals by the Energy Bureau (Fixed Decisions).

Table 1: PRP New Capacity Additions from 2025 to 2030.

Energy Resource	Total Capacity Additions 2025 to 2030 (MW)	Percent of Total Capacity
Distributed Generation	378	9%
Fixed Decision Generation	2,565	59%
Fixed Decision Batteries	1,365	31%
PRP Customer Programs	56	1%
Grand Total	**4,364**	**100%**

This large and rapid addition of new capacity is forecasted to result in a significant improvement to the overall reliability of the Puerto Rico Energy Supply. If adopted, the PRP is forecasted to reduce the expected unserved energy (EUE), an industry standard for measuring reliability, from 154 hours/year estimated in LUMA's most recent resource adequacy report,[1] to less than the industry standard target of 2.4 hours per year by 2032. This represents a , a 98% reduction in customer outages caused by utility generation.

Alternative Resource Plans

The characteristics of the 12 primary scenarios, and an accompanying list of performance indicators used to assess alternative resource plans, was crafted using input from stakeholders provided in the SETPR meetings, the Energy Bureau's Consultant and LUMA experts. The 12 primary scenarios describe a range of future conditions under which Puerto Rico's energy resource may be expected to operate. Analyzing the resulting resource plans provided LUMA sufficient information to define the Hybrid A Resource Plan that provided a flexible and lowest cost portfolio under the most likely future conditions.

A Brighter, Stronger Energy Future for Puerto Rico

The following sections of the 2025 IRP detail the system's current condition, load forecasts, generation resource options, modeling methodology, and scenario evaluation process. The document concludes with LUMA's Five-Year Action Plan, which outlines the specific steps necessary to implement the PRP and establish the foundation for a cleaner, more reliable, and economically sustainable energy system for Puerto Rico.

[1] Puerto Rico Electric System Resource Adequacy Analysis, October 31, 2024, filed in Case No. NEPR-MI-2022-002.

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List of Acronyms

TERM & ACRONYMS	DEFINITION
AC	alternating current
AEO	annual energy outlook
Ag. Land	agricultural land
ARRA	American Recovery and Reinvestment Act
ASAP	accelerated storage addition program
ATB	annual technology baseline
B100	biofuel
BACT	best achievable control technology
BTM	behind the meter
BTU	British thermal unit
BESS	battery energy storage system
BOP	balance of plant
CAES	compressed air energy storage
BTU	British thermal units
CAA	Clean Air Act
CAPEX	capital expenditures
CC	combined cycle
CFR	Code of Federal Regulations
CH4	methane
CHP	combined heat and power
CO	carbon monoxide
CO2	carbon dioxide
CO2e	carbon dioxide equivalent
COD	commercial operation date
CSP	concentrated solar power
CT	combustion turbine
CWA	Clean Water Act
DBESS	distributed battery energy storage system

TERM & ACRONYMS	DEFINITION
DC	direct current
DER	distributed energy resources
DG	distributed generation
DNER	Department of Natural and Environmental Resources
DOE	Department of Energy
DPV	distributed photovoltaics
DR	demand response
EE	energy efficiency
ELCC	effective load carrying capacity
EPA	Environmental Protection Agency
EPC	engineering, procurement, and construction
ESS	non-battery energy storage system
EUE	expected unserved energy
EV	electric vehicle
FES	flywheel energy storage
FO&M	fixed operations and maintenance
FPV	floating solar photovoltaic
FY	fiscal year
GDP	gross domestic product
GH	Guidehouse
GHG	greenhouse gas
GT	gas turbine
GW	gigawatt
GWh	gigawatt-hour
H2	hydrogen
HALEU	high-assay low-enriched uranium
HAP	hazardous air pollutants
HCl	hydrogen chloride
Hg	mercury

TERM & ACRONYMS	DEFINITION
HPTIT	high-pressure turbine inlet temperatures
IEA	International Energy Agency
IEEE	Institute of Electrical and Electronics Engineers
IPCC	Intergovernmental Panel on Climate Change
IRENA	International Renewable Energy Agency
IRP	Integrated Resource Plan
ISO	International Standardization Organization
IVU	impuesto de ventas y uso
kg	kilogram
kW	kilowatt
kWh	kilowatt-hour
LAER	lowest achievable emission rate
LAES	liquid air energy storage
LCA	life cycle assessment
LCOE	levelized cost of energy
LCOS	levelized cost of storage
LED	light-emitting diode
LOLE	loss of load expectation
LNG	liquefied natural gas
LPTIT	low-pressure turbine inlet temperatures
LWR	light-water restore
mAh	milliampere-hour
MACT	maximum achievable control technology
MATS	Mercury and Air Toxic Standards
MCM	thousands of circular mils
MSW	municipal solid waste
MW	megawatt
MWh	megawatt-hour
NAAQS	National Ambient Air Quality Standards

TERM & ACRONYMS	DEFINITION
NEA	Nuclear Energy Association
NEM	net energy metering
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NGCC	Natural Gas Combined Cycle
NOx	nitrogen oxide
NPDES	National Pollutant Discharge Elimination System
NREL	National Renewable Energy Laboratory
NSPS	New Source Performance Standards
NSR	New Source Review
NYISO	New York Independent System Operator
O&M	operations and maintenance
OMA	Operation and Maintenance Agreement
P3A	Puerto Rico Authority for Public Private Partnerships
PEM	proton exchange membrane
PEM	polymer electrolyte membrane
PHS	pumped hydro storage
PIR	Plan Integrado de Recursos
PJM	Pennsylvania- New Jersey- Maryland
PM	particulate matter
PPOA	power purchase and operating agreement
PPR	Plan Preferido de Recursos
PR	Puerto Rico
PR100	Puerto Rico Grid Resilience and Transitions to 100% Renewable Energy Study
PREB	Puerto Rico Energy Bureau
PREPA	Puerto Rico Electric Power Authority
PRP	Preferred Resource Plan
PSD	prevention of significant deterioration
PV	solar photovoltaic
PVRR	present value revenue requirement

TERM & ACRONYMS	DEFINITION
R100	renewable diesel
R&O	resolution and order
RCE	redox-couple electrolysis
RICE	reciprocating internal combustion engine
RFO	residual fuel oil
RFP	request for proposal
RPS	Renewable Portfolio Standard
SETPR	Solutions for the Energy Transformation of Puerto Rico
SETPR	Soluciones Energéticas para la Transformación de Puerto Rico
SIP	State Implementation Plan
SMR	small modular reactors
SO2	sulfur dioxide
SRP	System Remediation Plan
T&D	transmission and distribution
TOC	total organic carbon
TPA	transmission planning area
TWh	Terawatt-hour
UBESS	utility-scale battery energy storage system
UK	United Kingdom
ULSD	ultra-low sulfur diesel
UN	United Nations
UPV	utility-scale solar photovoltaic
US	United States
VO&M	variable operations and maintenance
VPP	virtual power plant
VRB	vanadium redox battery
VRFB	vanadium redox flow battery
Wh	watts-hour
WQC	Water Quality Certification

TERM & ACRONYMS	DEFINITION
WTE	waste-to-energy

Section 1:

Introduction and Summary of Conclusion

1.0 Introduction and Summary of Conclusion

1.1 Introduction

LUMA is committed to transforming Puerto Rico's energy system into one that is more reliable, resilient, cleaner, and sustainable for all its 1.5 million customers.

Since assuming operations of Puerto Rico's transmission and distribution (T&D) system in June 2021, LUMA has focused on critical priorities, consistent with the System Remediation Plan (SRP)[2] and approved budgets, to deliver better electric service. In just three years, LUMA has strengthened grid resilience by installing more than 35,500 new storm-resilient poles,[1] clearing vegetation along over 6,491 miles of power lines,[2] and deploying more than 10,418 grid-automation devices to reduce outage impacts.[3] LUMA has also replaced more than 180,800 streetlights[4] to enhance safety and has connected over 135,000 customers to rooftop solar.[5]

1.1.1 Puerto Rico's Integrated Resource Plan

One of LUMA's core planning responsibilities is to improve system reliability and resiliency through the development of an Integrated Resource Plan (IRP). The 2025 IRP is Puerto Rico's long-term plan for reliably and sustainably meeting the island's energy needs in the next 20-years ahead.

Since early 2022, LUMA has worked cooperatively and diligently to develop a realistic, pragmatic IRP that reflects industry standards, is grounded in accurate and comprehensive data and analyses, and aligns with customers' needs and priorities as Puerto Rico advances toward a more reliable, more resilient, and cleaner electric system. Notably, in developing the 2025 IRP, LUMA prioritized stakeholder engagement through the Solutions for the Energy Transformation of Puerto Rico (SETPR) initiative. Through this collaborative process. LUMA engaged with a broad range of customers and stakeholders to gather input on Puerto Rico's energy future. Understanding diverse views is an essential part of the 2025 IRP process and helps ensure that the final report incorporates broad stakeholder input.

1.1.2 LUMA's 2025 IRP Role: Data-Driven Planner

IRP development involves extensive data collection, iterative stakeholder outreach, and complex scenario planning and analysis. The growth of inverter-based resources (including solar and wind) and the expanding role of customer-controlled resources (including demand management and distributed generation) require more probabilistic approaches and risk metrics to assess variable resources and flexibility. In Puerto Rico, the planning challenge is compounded by the immediate vulnerabilities of an electric system that lacks necessary resources to meet current demand and includes aging infrastructure with many elements beyond their expected life. As a result, for a s portion of the time it is infeasible to operate under Prudent Utility Practice or typical North American utility standards. Although LUMA has made progress in improving overall reliability and carrying out key repairs[3], the system remains vulnerable and requires significant remediation.

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[2] See Puerto Rico Energy Bureau case Number NEPR-MI-2020-0019

[3] See latest Progress report of the System Remediation Plan https://energia.pr.gov/wp-content/uploads/sites/7/2025/08/20250814-MI20200019-Motion-to-Subm-Quarterly-Report-FY2025.pdf and the latest report on Vegetation Management Program at https://energia.pr.gov/wp-content/uploads/sites/7/2025/08/20250814-MI20190005-Motion-Subm-Vegetation-Mgmt-Progress-Report.pdf

LUMA is presenting a 2025 IRP that represents the least cost for customers and is compliant with current public energy policies. Puerto Rico's unique and complex electric system is a challenge due to all the fixed decisions in the first 7 years of the plan which represents an 80% increase in the average generation cost.

Throughout the development of the 2025 IRP, LUMA has maintained transparency and open communication with the Puerto Rico Energy Bureau (Energy Bureau or PREB) and stakeholders. LUMA's role is to serve as the data-driven planner and author of the 2025 IRP, using robust technical analyses and modeling to recommend an optimal plan for Puerto Rico. LUMA does not own or operate generation resources and is not primarily responsible for policy decisions that determine future energy resource projects.

As the operator of Puerto Rico's T&D system, LUMA enables the safe, reliable interconnection of any approved energy resource additions and performs multiple planning functions that assess the current and future configuration of the grid and interconnected resources. LUMA's position as the grid's planner and operator, but not an investor or operator of generation, provides a unique, customer-aligned perspective focused on outcomes that most benefit customers.

As part of the 2025 IRP process, LUMA continues to work with key stakeholders, including the Energy Bureau, the Financial Oversight and Management Board (FOMB), and the Puerto Rico Authority for Public Private Partnerships (P3A), to ensure plans are comprehensive, practical, and responsive to Puerto Rico's needs. LUMA also collaborated with customers through the SETPR engagement process to receive and incorporate meaningful feedback into the 2025 IRP analysis.

1.1.3 2025 IRP Timeline

On May 13, 2025, the Energy Bureau issued a Resolution and Order (R&O) recognizing the complexity and time intensity of resource modeling and the significant changes brought about by Act No. 1-2025. The May 13th R&O ordered LUMA to file on October 17, 2025, the final 2025 IRP with all portions of Regulation 9021, and the T&D plan elements except the T&D system implications of the Preferred Plan (PSSe analysis)[4]. The PSSe analysis of the Preferred Resource Plan (PRP) shall be filed on November 21, 2025. For the October 17, 2025, filing, LUMA was ordered to complete modeling of the Primary[5] 12 scenarios listed in the R&O and use the results in selection of the PRP. In the May 13th R&O, the Energy Bureau defined Scenarios 1 to 6 and Scenario 12 and left the remaining Scenarios 7 to 11 for LUMA to define. The definition of the twelve Primary Scenarios, including LUMA's definition of Scenarios 7 to 11 are shown in Table 2.

[4] The PSSe analysis is required in Regulation 9021 Section 2.03(J)(2)(e) to documents the transmission and distribution implications of the Preferred Resource Plan, including assessing if the plan requires incremental transmission or distribution mitigation or changes.

[5] LUMA renamed the "Core" Scenarios to "Primary" Scenarios so as not to be confused with LUMA reference to Core Resource Plans.

Table 2: Summary Description of Primary 12 Scenarios

Scenario	Scenario Description	Load	PV & UBESS CapEx	Natural Gas Plant CapEx + Bio Conversion Costs[6]	Level of DBESS Control	LNG Fuel Cost	Include Biodiesel	Fixed Decisions	Resulting Resource Plan
1	Base assumptions for all variables	Base	Base	Base	Base	Base	Yes	Base	Core Resource Plan A
2	High load conditions with base assumptions for other variables	High	Base	Base	Base	Base	Yes	Base	Core Resource Plan B
3	Base load with high natural gas plant capital costs	Base	Base	High	Base	Base	Yes	Base	Core Resource Plan C
4	Base load with low renewable energy capital costs and high fossil capital costs	Base	Low	High	Base	Base	Yes	Base	Core Resource Plan D
5	Base load with high natural gas fuel costs	Base	Base	Base	Base	High	Yes	Base	Core Resource Plan E
6	Base load with high natural gas fuel costs and high natural gas plant capital costs	Base	Base	High	Base	High	Yes	Base	Core Resource Plan F
7	Flex Run for Resource Plan B run under Scenario 1 conditions	Base	Base	Base	Base	Base	Yes	Base	Flex Resource Plan 1.B
8	Flex Run Resource Plan A run under Scenario 2 conditions	High	Base	Base	Base	Base	Yes	Base	Flex Resource Plan 2.A
9	Flex Run for Resource Plan A run under Low Load conditions	Low	Base	Base	Base	Base	Yes	Base	Flex Resource Plan Low.A
10	Flex Run of Resource Plan A run under Stress conditions	High	Base	High	Base	Base	Yes	Base	Resource Plan Stress.A
11	Flex Run of Resource Plan B run under Stress conditions	High	Base	High	Base	Base	Yes	Base	Resource Plan Stress.B
12	Base assumptions for all variables but biodiesel is unavailable	Base	Base	Base	Base	Base	No	Base	Core Resource Plan H

LUMA also expects to complete modeling for the five supplemental scenarios listed in Table 3 below and file the results of those no later than three weeks after the PSSe analysis is filed on November 21, 2025.This is in accordance with the May 13th R&O that allows LUMA to file the results of the Supplemental Scenarios with the November 21, 2025 filing, or shortly thereafter.

[6] Including the costs of biodiesel conversion was not included in the characteristic of the 12 scenarios in the May 13th R&O . LUMA chose to add biodiesel to this characteristic since LUMA judged it be consistent with the expressed intent of the Energy Bureau's Consultant's suggestion for this characteristic.

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Table 3: Summary Description of Five Supplemental Scenarios

Scenario	Scenario Description	Load	PV & UBESS CapEx	Natural Gas Plant CapEx + Bio Conversion Costs[7]	Level of DBESS Control	LNG Fuel Cost	Include Biodiesel	Fixed Decisions	Resulting Resource Plan
13	High DBESS control with base assumptions for other variables	Base	Base	Base	High	Base	Yes	Base	Resource Plan I
14	No NGCC 460 MW San Juan	Base	Base	Base	Base	Base	Yes	No NGCC	Resource Plan J
15	Marine Cable	Base	Base	Base	Base	Base	Yes	Base	Resource Plan K
16	Alternative RPS 1 – Assumes goal starts in 2025 and then ramps to 100% by 2050.	Base	Base	Base	Base	Base	Yes	Base	Resource Plan L
17	Alternative RPS 2 – Initial targets start between 2040 and 2044 and then ramps to 100% by 2050.	Base	Base	Base	Base	Base	Yes	Base	Resource Plan M

1.1.4 Puerto Rico's Electric System: A Legacy of Challenges

The Island's grid operates with outdated assets, limited generation, and infrastructure that has exceeded its expected service life. Table 4 summarizes the age and expected forced outage rates by fuel type of the current generation fleet. Note that this was the starting point for the 2025 IRP analysis.

Table 4: Summary Description of the Current PREPA Thermal Generation Fleet

Fuel	Total Nameplate Capacity (MW)	Total 2025 Dependable Capacity (MW)	Forced Outage Rate (%)	Average Age (years)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Since 1989, Puerto Rico's electric system has been severely impacted by six hurricanes, more than one every six years. In September 2017, Hurricane Irma significantly damaged the grid, leaving more than one million residents without power. Weeks later, Hurricane Maria crippled the system and required over a year to restore service to all customers, resulting in the worst blackout for any U.S. state or territory. In 2022, Hurricane Fiona damaged 50% of the island's transmission lines and distribution feeders. Although it caused an island-wide blackout, improvements in emergency planning and response enabled LUMA to restore service to 90% of customers within 12 days, a timeframe comparable to similar restorations by other North American utilities.

Efforts to address these issues are further challenged by Puerto Rico's unique grid and the long history of neglect by the previous operator. Prior to LUMA's operations, lack of investment and mismanagement left Puerto Rico's electric system well below the minimally acceptable reliability standards for utilities and, in many cases, worse than any peer utility, based on benchmarking conducted in accordance with the

[7] Including the costs of biodiesel conversion was not included in the characteristic of the 12 scenarios in the May 13, 2025, Energy Bureau order. LUMA chose to add biodiesel to this characteristic since LUMA judged it be consistent with the expressed intent of the Energy Bureau's Consultant's suggestion for this characteristic.

Institute of Electrical and Electronics Engineers (IEEE) 1366-2022. Unlike most of the continental United States, Puerto Rico is not interconnected with other electric systems and therefore lacks access to external reserves that could bolster resiliency, an additional challenge during disruptive events.

This document and associated appendices present LUMA's 2025 IRP, which provides the analysis and recommendations for energy supply resources for a 20-year period (2024 to 2044). The sections and appendices of this document are intended to fulfill the requirements of the Energy Bureau's Regulation 9021, Regulation on the Integrated Resource Plan.

The next section provides a summary of LUMA's conclusions and recommendations based on the broad array of scenarios represented in the first 12 cases and on the identification of the Preferred Resource Plan (PRP). LUMA is also preparing the T&D plans associated with the generation resource options. The 2025 IRP is a recommended plan for Puerto Rico and does not address the details of procurement. Federal funding for certain projects could alter the 2025 IRP and the associated Action Plan. These and other important issues will need to be addressed in other processes and later combined with the 2025 IRP to develop a complete roadmap for Puerto Rico's electric system.

The following sections present a diverse and analytically robust plan that was developed after careful analysis of several sets of future scenarios and resource plans that best responded to customer needs and Puerto Rico's energy public policy objectives.

1.2 Summary of Conclusions and Recommendations

1.2.1 Summary of Conclusions

LUMA has assumed the significant responsibility of preparing the 2025 IRP for Puerto Rico as the assigned representative of PREPA. LUMA also understands the profound impact that the historical and future energy supply has had and will continue to have on the people of Puerto Rico. During the SETPR meetings, LUMA understood that stakeholders expected LUMA to deliver a 2025 IRP that significantly improves energy resource reliability, decreases dependence on imported fossil fuels, improves generation technology diversity, and decreases the costs of electricity. The 2025 IRP fulfills each of these expectations except for delivering a plan that will lower power costs. Unfortunately, as the public has heard many times, after decades of neglect, the condition of electrical generation and T&D infrastructure requires both time and extraordinary investment to bring the electric system to acceptable reliability performance.

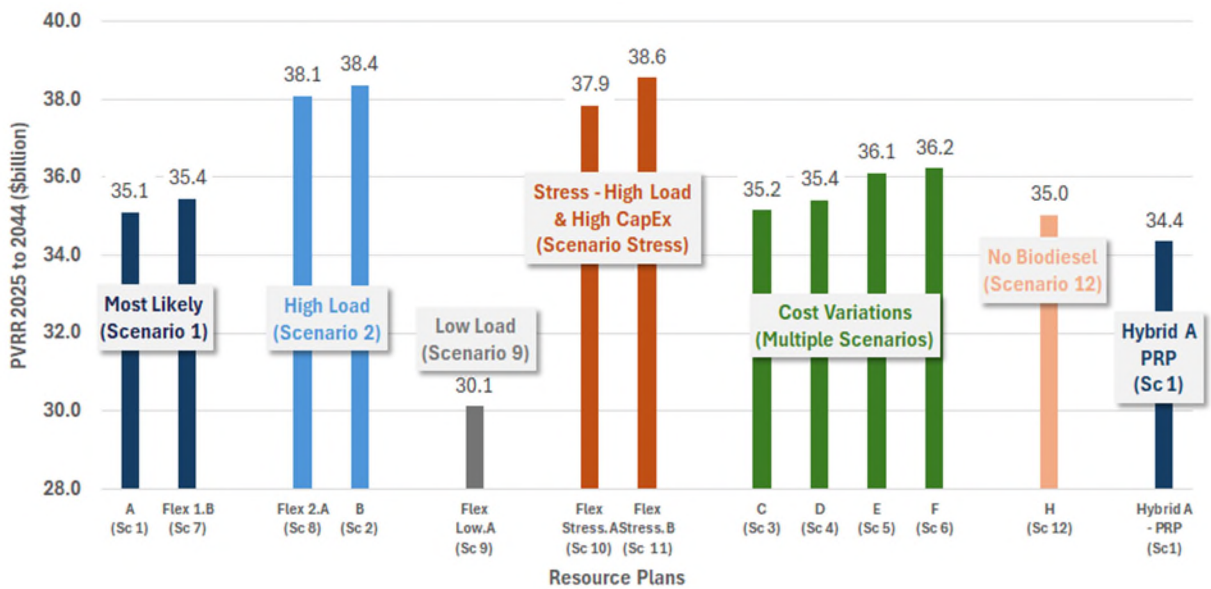
LUMA found the unusually high level of unplanned or forced outages of many of the existing generators created a unique modeling challenge to define resource plans that provided Puerto Rico with acceptable reliability performance as measured by loss of load expectations (LOLE) and Expected Unserved Energy (EUE). Both indicators are common industry measures of outage events where there is insufficient generation available to service some or all of the customer load. Insufficient available generation generally coincides with one or more units experiencing a forced outage that can instantaneously reduce the generation available to serve customer load. One of primary goals of this IRP was to improve the reliability of the generation fleet with goal of improving the LOLE and EUE performance. LUMA, working with its Technical Consultant and the developer of the resource modeling software used for this IRP, developed a unique modeling approach that incorporated a multi-step, iterative process to define resource plans that achieved acceptable LOLE and EUE performance. While the multi-step process was found to consistently deliver acceptable LOLE and EUE performance, the methodology significantly increased the time involved in the modeling process.

A key finding is that the resource additions and costs of the 2025 IRP are dominated by the Fixed Decisions. The Fixed Decisions represent planned resource additions and the AES retirement extension over the that were dictated outside the confines of the 2025 IRP.

Cost Results

Figure 1 shows the net present value revenue requirements (PVRR) resulting from modeling the 12 Primary Scenarios and Resource Plan Hybrid A that was defined based on the results of LUMA's sensitivity analyses.

Figure 1: Twenty-Year PVRR for Resource Plans Resulting from the 12 Primary Scenarios and Resource Plan Hybrid A



Sensitivity Analyss of Resource Plans A and H

The modeling results of the Primary 12 scenarios showed that Resource Plan Core H with no biofuel was the lowest-cost Resource Plan under the most likely conditions represented by Scenario 1. However, the difference between the PVRR results for Resource Plan Core A and H was only $0.1 billion or 0.2%. Based on the very close PVRR results, LUMA chose to further investigate both Resource Plans A and H. Resource Plan Hybrid A was created by LUMA building upon the results of the Primary 12 scenarios and the subsequent analysis and sensitivity runs. For Resource Plan Hybrid A, the accelerated storage addition program (ASAP)[8], Phase 2 Battery additions were changed from fixed decisions with a planned installation of 2026, to optional decisions that allowed later, need-based installations of 2031 and 2037, which resulted in a lower PVRR as shown in Figure 1. Based on these PVRR results and the analysis of the other indicators in the performance scorecard, LUMA selected Resource Plan Hybrid A as the preferred resource plan (PRP).

[8] See the Accelerated storage addition program case number NEPR-MI-2024-0002

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Fixed Decisions Dominate the Preferred Resource Plan

As established in Regulation 9021, LUMA assessed many options as candidate energy resource supply contributors to the 2025 IRP. However, it should be noted that a large portion of the long-term resource additions to the plan were determined by decisions that preceded LUMA's assessment of resource options and the 2025 IRP filing. Table 5 shows a summary of the energy resource additions in the first six years of the PRP. An analysis of that data shows that capacity added based on LUMA's PRP recommendations represents only 1% of the total capacity expected to be installed from 2025 to 2030, the first six years of the 2025 IRP. The remainder of the capacity additions in the first six years are either Fixed Decisions (90% of the total capacity combining fixed decision batteries and generation) that have already been approved and are in various stages of implementation or are forecasted distributed generation (9% of the total capacity), for which the actual quantity and timing of the additions will be determined by LUMA's customers.

Table 5: Preferred Resource Plan Additions By Category in First 6-Years (MW)

Energy Resource	Total 2025 to 2030 (MW)	Percent of Total Capacity
Distributed Generation (DPV and CHP) Implemented by Customers	378	9%
Fixed Decision Generation Implemented by Others	2,565	59%
Fixed Decision Batteries Implemented by Others	1,365	31%
PRP Recommended Customer Programs Implemented by LUMA	56	1%
Grand Total	**4,364**	**100%**

The Fixed Decisions represent not only 90% of the total capacity added in the first six years, but they also represent 41% of the total PVRR for the first six years ($6.1 billion PVRR attributable to the Fixed Decisions in the first seven years versus a total PVRR of $14.8 billion in the first six years). By illustrating these facts regarding LUMA's limited ability to impact the first six years of the 2025 PRP resource recommendations, LUMA does not intend to imply that it disagrees with the Fixed Decisions, nor that Fixed Decisions do not benefit the Puerto Rico energy supply. Rather, LUMA highlights these facts to reiterate that LUMA's ability to recommend changes to the future supply resources was limited by Fixed Decisions and the condition and reliability of the legacy generation fleet.

Table 6 shows that the recommended resource additions for the full 20-years of the PRP continue to be dominated by the magnitude of the Fixed Decisions, all of which occur in the first six years of the plan. Even when looking at the full 20 years of the IRP, the Fixed Decisions represent 60% of the total capacity additions and $16.2 billion in PVRR, or 47% of the $34.4 billion 20-year PVRR for the PRP.

Table 6: Preferred Resource Plan Additions 2025 to 2044

Energy Resource Technology	Total Additions 2025 to 2044 (MW)	Correction for Gas to Biodiesel Conversions (MW)	Total Corrected Capacity Additions 2025 to 2044 (MW)	Total Corrected Additions by Category (MW)	Category Percent of Total Corrected Additions (%)
Customer Distributed Generation				**1,209**	**17%**
CHP	100		100		

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Energy Resource Technology	Total Additions 2025 to 2044 (MW)	Correction for Gas to Biodiesel Conversions (MW)	Total Corrected Capacity Additions 2025 to 2044 (MW)	Total Corrected Additions by Category (MW)	Category Percent of Total Corrected Additions (%)
DPV	1,109		1,109		
Fixed Decision Generation				**2,565**	**35%**
PREPA HydroCo	38		38		
Emergency Generator	800		800		
Energiza	478		478		
New Genera Units	244		244		
Solar	200		200		
Tranche 1 Solar	739		739		
Tranche 2 Solar	66		66		
Fixed Decision Batteries				**1,790**	**25%**
ASAP Phase 1	190		190		
ASAP Phase 2	425		425		
New Genera Units	430		430		
Regulation Only BESS (4x25MW)	100		100		
Tranche 1 BESS	535		535		
Tranche 2 BESS	60		60		
Tranche 4 BESS	50		50		
PRP Recommended Customer Programs				**732**	**10%**
DR	661		661		
New Distributed Storage	71		71		
PRP Recommended Generation				**930**	**13%**
New Gas Gen	478		478		
New Gas Conversions and New Biodiesel	825	(373)	452		
New Genera Unit Biodiesel Conversions	244	(244)	0		
Legacy Unit Biodiesel Conversions	75	(75)	0		
Total	**7,918**	**(692)**	**7,226**	**7,226**	**100%**

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The PRP also recommends significant retirements of legacy generators. Table 7 summarizes the retirement recommendations over the 2025 to 2044 period addressed in the 2025 IRP. Further details on the PRP additions and retirements are presented and discussed in Section 8.0 of this report.

Table 7: Preferred Resource Plan Retirements 2025 to 2044

Energy Resource Technology	Total 2025 to 2044 (MW)	Correction for Gas to Biodiesel Conversions (MW)	Total Corrected Capacity Retirements 2025 to 2044 (MW)
Legacy Land Fill Gas Gen	4		4
Emergency Generators	800		800
Legacy Thermal Generation	2,039		2,039
Legacy Peaker Generation	147		147
New Gas Unit Biodiesel Conversions	373	(373)	0
New Genera Unit Biodiesel Conversions	244	(244)	0
Legacy Unit Biodiesel Conversions	75	(75)	0
Legacy Solar Expiration of Contract	107		107
Grand Total	**3,789**	**(692)**	**3,097**

Generation Fuel Transition – From Fossil to Renewable Fuels

As part of its assessment of resource options deemed plausible candidates to assess for the future of Puerto Rico, LUMA reviewed both existing and potential future generation technologies and fuels in the 2025 IRP. Puerto Rico has legislated changes to its energy resource supply to move from the supply from fossil fuels to renewable energy resources. In addition to targeting the electricity supply fleet to be 100% renewable by 2050, Puerto Rico has mandated the retirement of its coal generators, encouraged the rapid retirement of its legacy generators that use heavy fuel oil, and mandated the ability to burn clean hydrogen fuel in any new thermal generators. LUMA considered these legislated and regulated directions in light of the costs and technological maturity of energy supply options available to Puerto Rico. *Section 7 – Fuel and Other General Assumptions and Forecasts* provides an overview, discussion and recommendations regarding the generation technologies, energy storage technologies and fuels considered for this 2025 IRP.

Out of all the generation technology and fuel options considered, the analysis showed that liquefied natural gas (LNG) remains the best and lowest cost transition fuel option for Puerto Rico. LNG and the simple cycle gas turbine (GTs) and combined cycled gas turbine (CCs) generation technologies fueled with gasified LNG have lower greenhouse gases, nitrogen oxide (NOx) and sulfur oxide (SOx) air emissions than existing coal, heavy fuel oil and diesel fueled generation [9] on the island. LUMA's analyses indicate that using LNG as the initial fuel choice for most of the new generation recommended in the PRP appears to be cost effective based on current fuel and technology forecasts. However, LNG is not a renewable fuel and will not contribute to Puerto Rico's goal of 100% renewable supply by 2050.

[9] Center for Corporate Climate Leadership. (2025). *Emission Factors for Greenhouse Gas Inventories*. U.S. Environmental Protection Agency. https://www.epa.gov/system/files/documents/2025-01/ghg-emission-factors-hub-2025.pdf

With the need to transition to renewable supply options, LUMA assessed options to replace or transition from LNG fuel generation. The primary options LUMA considered included:

- Solar and wind generation – these options provide renewable energy but require the addition of energy storage to provide a firm resource to provide power during Puerto Rico's evening peak and during periods of low wind and solar energy. While these generation types do not require purchased fuel, their initial capital costs together with variable energy production result in these resources only becoming the most cost-effective options for Renewable Portfolio Standard (RPS) compliance.

- Hydrogen fuel –this option is an already mandated for future thermal generation additions in Puerto Rico. However, hydrogen is not yet in commercial use for utility-scale generation for a variety of reasons. Gas turbines are the most plausible generation technology to use hydrogen fuel, but turbines that are able to burn 100% hydrogen fuel are not yet commercially available. In addition to the technological challenges associated with burning 100% hydrogen fuel, the cost of both importing and producing the fuel, the latter of which is more likely for Puerto Rico, is significantly higher than the other options considered. Given the projected costs and technological hurdles that must be overcome for Puerto Rico to plan on using hydrogen as a renewable fuel, LUMA assessed hydrogen but did not include it in the modeling of resource options.

- Biodiesel – LUMA included this option as a renewable fuel, and it is part of the PRP. Biodiesel is similar to fossil-based diesel fuel but has different characteristics that require it to be handled differently. Biodiesel is currently in commercial use on a wide scale in the USA and internationally and is produced in small quantities in Puerto Rico. The current cost of renewable diesel has limited its use to being blended with fossil-based diesel for primarily renewable transportation fuel. The fuel can be easily blended at any percentage with fossil-based fuel to reduce its costs. Based on LUMA's analysis, a blend of biodiesel with fossil-based diesel appears to offer a cost-effective option for Puerto Rico to transition from fossil fuels to renewable generation. The PRP includes most of the new thermal generation being added to include dual fuel capability. Due to constraints on the natural gas supply during winter months, a number of locations require new generation to include dual fuel capability with an alternate fuel to natural gas. Many generators choose to meet this requirement with diesel as the alternate fuel. These new thermal generators in the PRP would start their life burning natural gas then transition to a blended liquid fuel mix of biodiesel and fossil-based diesel that would include annual increases in the portion of biodiesel in the fuel blend, ultimately reaching 100% biodiesel by 2049.

- Renewable diesel – this option is a renewable fuel that is completely interchangeable with fossil-based diesel fuel. While it also uses biological-based feedstock, the processes required to produce it are more expensive and complex than those used to produce biodiesel. Renewable diesel is currently in commercial use in California and Europe and is produced both in the United States and internationally. However, the current cost of renewable diesel has limited its use to primarily transportation fuel to displace fossil-based diesel. The fuel can be easily blended at any percentage with fossil fuel to reduce its costs. Renewable diesel could be an option for Puerto Rico to generate renewable energy, if the price of renewable diesel reaches a point that is lower than the biodiesel fuel discussed above. Renewable diesel is completely interchangeability with fossil-based diesel and would be a better option than biodiesel.

1.2.2 Summary of Recommendations

Based on the results of its modeling and analysis, LUMA recommends that the Energy Bureau approve Resource Plan Hybrid A as the PRP. LUMA's recommendation is based on its current projection of capital costs and fuel costs for the technologies considered. Through the scenarios required by the Energy Bureau, the 2025 IRP analysis shows that the biodiesel-based Resource Plan Core A remains the lower cost option even when the costs of the gas turbine-based generation and fuels in Resource Plan Core A were increased while also decreasing the expected capital costs for wind, solar and battery.

However, partly based on the PRP's early resource additions being dominated by Fixed Decisions and partly due to the design of LUMA's Flexibility Analysis, the PVRR differences between candidate Resource Plans, under the same load conditions, are quite small in comparison to the total PVRR. It can be inferred from these results that while the PRP is the best choice based on LUMA's analysis, small changes to the actual costs of wind or solar capital costs, LNG costs, or biodiesel costs could change the selection of the best Resource Plan for Puerto Rico. Therefore, whether or not the Energy Bureau approves LUMA's recommended PRP, in whole or in part, LUMA recommends that all future energy resource solicitations for generation in Puerto Rico include the following:

- Biodiesel, renewable diesel, solar, and land-based wind technology should all be acceptable options, and the final resource selection should be based on a technology-agnostic assessment of the bid prices, performance characteristics and commercial terms
- Any new thermal generation should be designed to use either LNG, fossil-based diesel, renewable diesel, 100% biodiesel, and fuel blends
- Preferred interconnection locations should be determined by LUMA and provided to the bidders to minimize the transmission system network upgrades required to interconnect the units.

Finally, LUMA has recommended the Energy Bureau compel regular status reports for all the projects included in the action plan.

Section 2:

Planning Environment

2.0 Planning Environment

2.1 Overview of Planning Environment

LUMA and electric utilities must continuously plan across various projection periods—from short-term, daily, and hourly operational decisions to long-term strategies that may impact the utility system for decades. This planning occurs within an uncertain and dynamic environment influenced by various factors, including weather patterns, macroeconomic conditions, local economic trends, the financial health of the utility, and evolving local and federal laws and regulations.

The Planning Environment section of the IRP focuses on identifying and analyzing key planning and regulatory drivers that shape PREPA's operational context. It includes list of the relevant laws, regulations, and industry standards that impact the requirement for, or availability of, energy efficiency, renewable energy, fuel alternatives, or other resource requirements, and that impact existing utility resources or resource choices at the present time and throughout the planning period. LUMA describes the impacts of these laws, regulations, and standards on its IRP throughout the Load Forecast, Existing Resources, Resource Needs Assessment, New Resource Options, Assumptions and Forecasts, Resource Plan Development, and Action Plan Sections of this report and its supporting testimony.

Puerto Rico's energy regulatory framework is a mix of recent and foundational statutes that have significantly transformed the legal landscape in the last 40 decades of Puerto Rico's public energy policies. Starting with Act 83-1941, which created PREPA as the public utility in charge of the generation and transmission of electricity in Puerto Rico. Act No. 82- 2010 established the Public Policy for Energy Diversification through Sustainable and Alternative Renewable Energy in Puerto Rico Act. After years of poor maintenance and increasing costs in generation, the Puerto Rico Energy Transformation and Relief Act (Act No. 57 of May 27, 2014, as amended) was enacted establishing the Energy Bureau as an independent regulator with authority over rates, planning, interconnection, net metering, wheeling and performance metrics. Act 120-2018 was enacted in the direct aftermath of Hurricane Maria (2017), when PREPA's deteriorated grid collapsed causing an Island wide blackout that lasted for months. The law's purpose was to enable the transformation and modernization of PREPA, authorizing to sell, transfer, or enter public-private partnerships to operate PREPA's assets and operations. Through Act 120-2018 LUMA was contracted to operate the transmission and distribution system and Genera to manage the generation.

Recent legislative developments have introduced new challenges and areas of opportunity. Act No. 1 of March 19, 2025 (Act No. 1-2025) seeks to align Puerto Rico's energy public policy with the urgent realities of the Island's energy emergency. This includes addressing the critical need to expand generation capacity to meet demand and improve the reliability and resilience of the electric service. The act amends provisions of prior legislation, Puerto Rico Energy Public Policy Act (Act No. 17-2019 Act 82-2010 and Act 57-2014.

Section 3.0 outlines the planning assumptions and environmental impacts related to the load and cost forecasts used in the analysis.

2.2 Laws, Rules, Regulations, Industry Standards

The planning, design, construction, operation, and administration of Puerto Rico's energy system shall be conducted in full compliance with all applicable federal and Commonwealth laws, regulations, codes, industry standards, and recognized best practices. This is essential to ensure the development of a secure, resilient, reliable, and robust energy infrastructure. Accordingly, this section of the Integrated Resource Plan (IRP) includes a non-exhaustive list of key legal authorities, regulatory instruments, codes, and industry standards that are relevant to, and should inform, the planning and operation of Puerto Rico's energy system, as well as the development and implementation of the IRP. See Tables.

2.2.1 Federal Laws

Non-exhaustive list of relevant federal laws with a brief description.

Table 8: Federal Laws

Federal Laws	Description
Clean Air Act	The Clean Air Act (CAA), administered by the U.S. Environmental Protection Agency (EPA), is a foundational environmental statute that regulates air emissions from stationary and mobile sources to protect public health and the environment; its implementation has significantly impacted the energy sector by mandating emission controls, driving the adoption of cleaner technologies, and encouraging the development of renewable energy sources, while requiring states to develop State Implementation Plans (SIPs) to meet federal air quality standards—thereby fostering a regulatory framework that aligns energy production with environmental sustainability and long-term climate goals.
Clean Water Act	The Clean Water Act (CWA) establishes federal authority over pollutant discharges into U.S. waters and requires energy sector facilities to obtain National Pollutant Discharge Elimination System (NPDES) permits for operations that may impact water quality. These regulatory obligations have driven the energy industry to adopt advanced wastewater treatment technologies, implement spill prevention protocols, and enhance environmental compliance practices to protect aquatic ecosystems and ensure operational accountability.
Department of Energy Organization Act	The Department of Energy Organization Act of 1977 established the U.S. Department of Energy (DOE) to centralize federal energy functions and implement a unified national energy policy. The Act consolidated regulatory, research, and policy responsibilities, providing a legal framework for energy production, conservation, and innovation, and significantly shaping the governance of the U.S. energy sector.

Federal Laws	Description
Endangered Species Act	The Endangered Species Act of 1973 (ESA), establishes a comprehensive legal framework for the conservation of threatened and endangered species and the protection of their critical habitats. Administered by the U.S. Fish and Wildlife Service (FWS) and the National Marine Fisheries Service (NMFS), the Act mandates federal agencies to consult with these services under Section 7 prior to undertaking actions that may jeopardize listed species or adversely modify designated critical habitats. In the context of the energy industry, the ESA imposes procedural and substantive obligations that affect project siting, permitting, and operational practices particularly for infrastructure development, transmission corridors, and vegetation management. While the Act has been instrumental in preventing species extinction and preserving biodiversity, it also presents regulatory challenges for energy developers, requiring careful coordination to balance environmental compliance with energy production and land use objectives
Energy Conservation Reauthorization Act of 1998	The Energy Conservation Reauthorization Act of 1998 (Public Law 105-388) amended multiple federal energy statutes to extend and enhance energy conservation initiatives. It authorized appropriations through FY 2003 for state energy conservation programs, weatherization assistance, and energy efficiency improvements in schools and hospitals. The Act extended federal agencies' authority to enter into energy savings performance contracts and made permanent the President's authority to prioritize energy-related materials during supply emergencies. It also established biodiesel credit mechanisms under the Energy Policy Act of 1992, expanded reporting requirements for federal fleet alternative fuel compliance, and supported energy development on Indian lands. Additionally, it increased funding for uranium enrichment decontamination and decommissioning activities.
Energy Independence and Security Act of 2007	The Energy Independence and Security Act of 2007 (Pub. L. 110-140) is a comprehensive federal statute enacted to enhance U.S. energy security, increase the production and use of renewable fuels, and improve energy efficiency across multiple sectors. Key provisions include the establishment of a national Corporate Average Fuel Economy (CAFE) standard of 35 miles per gallon by model year 2020, a Renewable Fuel Standard (RFS) mandating 36 billion gallons of biofuels by 2022, and new efficiency standards for appliances and lighting. The Act also repealed certain oil and gas tax incentives to offset implementation costs and reinforced federal agency energy reduction mandate.

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Federal Laws	Description
Energy Policy Act of 1992	The Energy Policy Act of 1992 (Pub. L. 102–486), enacted on October 24, 1992, is a comprehensive federal statute designed to advance U.S. energy independence, improve energy efficiency, and promote the development of clean and alternative energy sources. It also established federal mandates for alternative fuel vehicle acquisition in certain fleets, set efficiency standards for buildings and equipment, and authorized incentives for renewable energy technologies. Collectively, the Act laid the foundation for modern energy policy by reducing reliance on imported energy and fostering sustainable energy practices.
Energy Policy Act of 2005	The Energy Policy Act of 2005 (Pub. L. 109–58) establishes a comprehensive legislative framework to advance U.S. energy production, infrastructure, and security. The Act addresses a broad range of energy domains, including energy efficiency, renewable energy, oil and gas, coal, nuclear energy, tribal energy development, hydrogen, electricity, and climate change technologies. It also includes provisions related to vehicles and motor fuels, such as ethanol,and authorizes energy tax incentives to promote investment in emerging technologies. Notably, the Act provides federal loan guarantees for projects deploying innovative technologies that reduce greenhouse gas emissions and mandates increased biofuel blending requirements in transportation fuels. Through these measures, the Act aims to diversify the national energy portfolio, enhance energy independence, and support environmental sustainability.
The Federal Insecticide, Fungicide, and Rodenticide Act	The Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA), establishes the federal regulatory framework for the registration, distribution, sale, and use of pesticides in the United States. Administered by the U.S. Environmental Protection Agency (EPA), FIFRA requires that all pesticides be registered prior to distribution and mandates that their use not pose unreasonable adverse effects on human health or the environment.
Federal Power Act	The Federal Power Act (FPA), originally enacted in 1920 as the Federal Water Power Act and codified at 16 U.S.C. §§ 791a et seq., provides the statutory framework for federal regulation of interstate electricity transmission, wholesale power sales, and hydroelectric licensing. Administered by the Federal Energy Regulatory Commission (FERC), the Act aims to ensure just, reasonable, and non-discriminatory rates while supporting the coordinated development of the nation's electric infrastructure. The FPA has been amended to address evolving energy challenges, including reliability standards, market oversight, and integration of renewable resources

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Federal Laws	Description
Infrastructure Investment and Jobs Act (also known as the Bipartisan Infrastructure Law)	The Infrastructure Investment and Jobs Act of 2021 (Pub. L. 117–58), authorizes over $75 billion in funding for energy-related programs administered primarily by the U.S. Department of Energy. The Act supports large-scale investments in carbon capture, utilization, and storage (CCUS), hydrogen infrastructure, grid modernization, clean energy demonstrations, and advanced nuclear technologies. It establishes regional Direct Air Capture (DAC) hubs, expands clean energy manufacturing, and promotes decarbonization through research, development, and deployment initiatives aimed at achieving net-zero emissions by 2050.
Merchant Marine Act of 1920 (also known as the Jones Act)	The Merchant Marine Act of 1920, commonly known as the Jones Act, is a federal statute that governs maritime commerce in U.S. waters and between U.S. ports. It requires that all goods transported by water between U.S. ports be carried on vessels that are U.S.-built, U.S.-owned, and U.S.-crewed. This requirement has had notable implications for the energy sector, particularly in the transportation of fuel and energy products, influencing shipping logistics and infrastructure planning. The Act also includes provisions for national security and allows for waivers in emergency situations to ensure continuity of supply.
Natural Gas Act	The Natural Gas Act of 1938, Pub. L. No. 75-688, established federal oversight of interstate natural gas sales and transportation, FERC authority to regulate rates and infrastructure to ensure just, reasonable, and non-discriminatory practices. While preserving state jurisdiction over intrastate activities, the Act laid the foundation for federal energy regulation and was later amended to reflect market liberalization and evolving energy policy objectives.. Subsequent amendments, including the Natural Gas Policy Act of 1978 and the Energy Policy Act of 2005, expanded and modernized FERC's authority to address evolving market conditions, promote competition, and ensure reliability and environmental compliance in the natural gas sector.
National Institute of Standards and Technology Act	The National Institute of Standards and Technology Act establishes the National Institute of Standards and Technology (NIST) within the U.S. Department of Commerce to advance innovation and industrial competitiveness through the development of measurement science, standards, and technology. The Act authorizes the creation of national laboratories supporting U.S. industry in adopting advanced technologies and includes provisions for ongoing reauthorization, including support for international standards development and basic research in physical and engineering sciences. .

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Federal Laws	Description
National Technology Transfer and Advancement Act of 1995	The National Technology Transfer and Advancement Act of 1995 (NTTAA) was enacted to facilitate the commercialization of federally funded technologies and to strengthen U.S. industrial competitiveness. The Act authorizes federal agencies and laboratories to enter into cooperative research and development agreements (CRADAs) and to grant exclusive licenses for inventions resulting from such collaborations, thereby promoting private-sector investment in innovation. Additionally, the NTTAA mandates that federal agencies utilize technical standards developed or adopted by voluntary consensus standards bodies in lieu of government-unique standards, where practicable, to enhance efficiency, interoperability, and regulatory consistency.
Public Utility Holding Company Act Of 2005	Public Utility Holding Company Act of 2005 (PUHCA 2005) was enacted as part of the Energy Policy Act of 2005, the Public Utility Holding Company Act of 2005 repealed the 1935 Act and transferred regulatory oversight of utility holding companies from the Securities and Exchange Commission (SEC) to the Federal Energy Regulatory Commission (FERC). PUHCA 2005 authorizes FERC to access books and records of holding companies and their affiliates, review cost allocations for non-power goods and services, and ensure transparency and consumer protection in affiliate transactions. The Act streamlines regulatory requirements while preserving essential oversight to prevent market abuses and support efficient utility operations
Public Utility Regulatory Policies Act of 1978	The Public Utility Regulatory Policies Act of 1978 (PURPA), enacted as part of the National Energy Act, was designed to promote energy conservation, enhance electric utility efficiency, and encourage the development of renewable energy and cogeneration. It introduced the concept of "qualifying facilities" (QFs), allowing non-utility generators to sell electricity to utilities at avoided cost rates, thereby fostering competition in the energy market. PURPA also required state regulators to consider energy efficiency standards and equitable rate structures, marking a foundational shift toward deregulation and diversification in the U.S. energy sector.

Federal Laws	Description
Puerto Rico Oversight, Management, and Economic Stability Act	The Puerto Rico Oversight, Management, and Economic Stability Act (PROMESA), establishes a federal framework to address Puerto Rico's fiscal crisis through debt restructuring and fiscal oversight. The Act created the Financial Oversight and Management Board (FOMB), an independent entity with authority to approve fiscal plans, budgets, and restructuring agreements. PROMESA also provides for a court-supervised process under Title III for debt adjustment and includes provisions for expedited approval of critical infrastructure projects, access to financial records, and contract review to ensure compliance with approved fiscal plans.
Rural Electrification Act of 1936	The Rural Electrification Act of 1936, enacted as part of the New Deal, established the Rural Electrification Administration to provide federal loans for the development of electric infrastructure in underserved rural areas. By supporting the formation of non-profit cooperatives, the Act enabled widespread electrification, significantly improving living standards and agricultural productivity. Its framework has since evolved to support additional rural infrastructure, including telecommunications and broadband services electric cooperatives. Its validity and relevance persist today, as the Act has been adapted to support modern infrastructure needs
Robert T. Stafford Disaster Relief and Emergency Assistance Act	The Robert T. Stafford Disaster Relief and Emergency Assistance Act of 1988 serves as the cornerstone of federal disaster response in the United States, empowering the President to authorize federal aid through FEMA to support state and local recovery efforts. It provides structured assistance for public infrastructure restoration, individual relief, and hazard mitigation. In Puerto Rico, the Stafford Act has played a critical role in post-disaster recovery, particularly following Hurricanes Irma, Maria and Fiona, among others, by enabling federal funding for grid stabilization, modernization, and resilience projects. These efforts have been essential in addressing the island's longstanding energy vulnerabilities and in supporting the transition toward a more decentralized and sustainable power system.

Federal Laws	Description
The Inflation Reduction Act of 2022	The Inflation Reduction Act of 2022 is a landmark federal initiative aimed at accelerating the transition to a clean energy economy by reducing carbon emissions and investing in renewable energy. It provides substantial tax incentives, to lower the cost of clean energy deployment, and loan authority to support energy infrastructure projects. The Act also introduces the Energy Infrastructure Reinvestment Program to modernize aging facilities, prioritizes environmental justice through targeted investments in disadvantaged and rural communities, and strengthens domestic clean energy manufacturing. Collectively, these measures are expected to reshape the U.S. energy landscape and drive long-term sustainability and resilience.

2.2.2 Federal Rules & Regulations

Non-exhaustive list of relevant federal rules and regulations with a brief description as compiled under the Code of Federal Regulation.

Table 9: Federal Rules and Regulations

Federal Rules & Regulations	Description
Code of Federal Regulation	The Code of Federal Regulations (CFR) serves as the official codification of the general and permanent rules issued by federal agencies, including those governing energy policy under Title 10. These regulations establish legally binding standards to promote energy efficiency, support the deployment of renewable energy technologies, and mitigate environmental impacts. Key provisions include mandatory energy performance standards for federal buildings, requiring significant reductions in fossil fuel consumption and alignment with updated industry benchmarks. Additionally, the CFR outlines environmental safeguards and efficiency measures that guide both public and private sector compliance, reinforcing the federal government's commitment to sustainable energy development and environmental stewardship.

2.2.3 Commonwealth of Puerto Rico Laws

Non-exhaustive list with a brief description of Commonwealth of Puerto Rico relevant laws.

Table 10: Commonwealth of Puerto Rico Laws

Commonwealth of Puerto Rico Laws	Description
Commonwealth of Puerto Rico Energy and Aqueduct and Sewer Service Subsidy Reform and Debt Payoff Act, Act No. 22-2016	The Electricity, Water and Sewer Services Subsidies and Overdue Payments Reform Act, Act No. 22-2016, restructures the subsidies and payment obligations across various sectors, aiming to improve the financial stability of PREPA and PRASA. The Act imposes new limitations on the use of tax credits for electricity, water, and sewer services, particularly affecting grantees under the Economic Incentives Act (Act No. 73-2008) and the Tourism Development Act (Act No. 101-1985). It restricts the application of certain tax credits for operational costs unless certified by the Treasury and prohibits new grants from including credits for energy cost reductions or strategic investments. Hotels and paradores with existing credits may retain them under specific conditions, while new credits are limited in scope and duration. The Act also standardizes utility rates for churches, social welfare organizations, and public housing residents, and mandates that government agencies budget for utility payments and debt repayment plans. This reform reflects a broader effort to enhance fiscal discipline and ensure equitable access to essential services.
Electric Power Authority Revitalization Act, Act No. 4-2016	Act No. 4-2016, establishes a comprehensive legal framework to restructure the Puerto Rico Electric Power Authority (PREPA) and address its financial insolvency, operational inefficiencies, and governance challenges. The Act authorizes the creation of the Puerto Rico Electric Power Authority Revitalization Corporation, which is empowered to issue Restructuring Bonds backed by a Transition Charge imposed on all PREPA customers. It amends multiple statutes, including the PREPA Act and the Energy Transformation and RELIEF Act, to enhance regulatory oversight, modernize infrastructure, promote renewable energy integration, and ensure rate transparency. The legislation also strengthens the role of the Puerto Rico Energy Commission, mandates governance reforms, and establishes mechanisms for public participation and consumer protection. Through these measures, the Act aims to stabilize PREPA's finances, restore investor confidence, and lay the foundation for a more reliable, efficient, and sustainable energy system in Puerto Rico.
Government of Puerto Rico Uniform Administrative Procedure Act, Act No. 38-2017	Act No. 38-2017 establishes a comprehensive and standardized framework for administrative procedures across Puerto Rico's government agencies. It aims to enhance the quality, efficiency, and transparency of public services by ensuring due process and promoting uniformity in rulemaking, adjudication, and judicial review.
Green Energy Incentives Act of Puerto Rico, Act No. 83-2010	Act No. 83-2010, the Green Energy Incentives Act of Puerto Rico, was enacted to promote the development and integration of renewable energy sources as part of the island's long-term energy strategy. The Act establishes the Green Energy Fund, which provides financial incentives to support the deployment of renewable energy technologies and infrastructure. It also facilitates the creation of a market for Renewable Energy Certificates (RECs), enabling broader participation in clean energy initiatives. Through these mechanisms, the Act aims to diversify Puerto Rico's energy portfolio, reduce dependence on fossil fuels, and foster a sustainable and resilient energy system.

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Commonwealth of Puerto Rico Laws	Description
Law for the Transformation of the Electric System of Puerto Rico, Act No. 120-2018	Act No. 120-2018, known as the Law for the Transformation of the Electric System of Puerto Rico, provides the legal foundation for restructuring the island's energy sector through privatization and public-private partnerships. Enacted in the aftermath of Hurricane Maria, the law responds to decades of operational inefficiencies, financial instability, and infrastructure vulnerability within the Puerto Rico Electric Power Authority (PREPA). It authorizes the transfer of PREPA's assets and operations to private entities, with the goal of modernizing the electric grid, integrating renewable energy sources, and reducing reliance on fossil fuels. The Act also emphasizes the importance of regulatory oversight, transparency, and public accountability to ensure that the transformation results in a more resilient, efficient, and affordable energy system. By attracting private investment and technical expertise, the law seeks to position Puerto Rico for long-term energy sustainability and economic growth.
Law to Guarantee Access to Essential Services in Emergency Situations, Act No. 59-2023	Act No. 59-2023 is a legislative measure enacted to guarantee uninterrupted access to essential services—such as water, electricity, telecommunications, healthcare, and transportation—during emergencies, including natural disasters and public health crises. The law mandates that both public and private service providers develop and implement contingency plans prioritizing vulnerable populations, including low-income households, the elderly, and individuals with disabilities. It establishes a framework for government oversight, coordination, and accountability, while also introducing affordability protections such as temporary subsidies and payment deferrals. By reinforcing legal safeguards and ensuring equitable access, the Act aims to strengthen Puerto Rico's emergency preparedness resilience in times of crisis.
Law to Institute the Procedure for Municipalities to Normalize or Restore Electrical, Aqueduct, and Sewer Systems When a State of Emergency Has Been Decreed, Act No. 107-2018	Act No. 107-2018, titled the Law to Institute the Procedure for Municipalities to Normalize or Restore Electrical, Aqueduct, and Sewer Systems During a State of Emergency, empowers Puerto Rico's municipalities to take direct action in restoring critical infrastructure when a state of emergency is declared. The law authorizes local governments to coordinate and execute emergency repairs to electrical, water, and sewer systems, particularly when centralized agencies are unable to respond promptly. It establishes protocols for interagency coordination, access to emergency funding, and compliance with technical standards.
Procedures in Emergency Situations or Events Act No. 76-2000	Act No. 76-2000, known as the Procedures in Emergency Situations or Events Act, establishes an expedited legal and administrative framework to facilitate the issuance of permits, endorsements, consultations, and certifications for public works and infrastructure projects during declared states of emergency in Puerto Rico. The law aims to ensure timely and coordinated responses by enabling government agencies and municipalities to bypass standard bureaucratic procedures while maintaining compliance with applicable contracting and procurement regulations. It underscores the importance of safeguarding public welfare, restoring essential services, and accelerating recovery efforts, particularly in the aftermath of natural disasters or other critical events. The Act also reinforces accountability by requiring proper documentation, adherence to fiscal controls, and post-emergency audits to ensure transparency and lawful use of public funds.

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Commonwealth of Puerto Rico Laws	Description
Public Policy on Energy Diversification by Means of Sustainable and Alternative Renewable Energy in Puerto Rico Act, Act No. 82-2010	Act No. 82-2010, known as the Public Policy on Energy Diversification through Sustainable and Alternative Renewable Energy in Puerto Rico Act, establishes a comprehensive legal framework to promote the integration of renewable energy sources into the island's energy system. The law sets forth a Renewable Portfolio Standard (RPS) with defined targets for short-, medium-, and long-term adoption of technologies such as solar, wind, and biomass. It introduces Renewable Energy Certificates (RECs) to incentivize clean energy production and mandates compliance through monitoring and reporting mechanisms. By reducing dependence on fossil fuels, enhancing energy security, and mitigating environmental impacts, the Act supports Puerto Rico's transition toward a more resilient, diversified, and sustainable energy future.
Puerto Rico Electric Power Authority Act, Act No. 83-1941	Act No. 83-1941, known as the Puerto Rico Electric Power Authority Act, established the Puerto Rico Electric Power Authority (PREPA) as a public corporation responsible for the generation, transmission, and distribution of electricity across the island. The Act aimed to ensure affordable, reliable energy to support economic development and improve quality of life. However, over time, it faced severe challenges, including financial mismanagement, political interference, and deteriorating infrastructure, culminating in a multibillion-dollar debt crisis and widespread service failures, particularly after Hurricane Maria. In response, Puerto Rico enacted structural reforms, including the privatization of transmission and distribution (via LUMA Energy) and generation assets (via Genera PR). Today, PREPA operates under the oversight of the Puerto Rico Energy Bureau Puerto Ricos independent body responsible for regulating monitoring and enforcing the energy public policy and developing the Integrated Resource Plan (IRP), which aims to transition the island toward a more resilient, sustainable, and decentralized energy system.
Puerto Rico Energy Cooperatives Act 258-2018	Act No. 258-2018, known as the Puerto Rico Energy Cooperatives Act, establishes the legal and regulatory framework for the creation, governance, and oversight of energy cooperatives on the island. Enacted in the aftermath of Hurricane Maria, the law aims to decentralize energy generation and empower communities to develop and manage their own renewable energy systems. It authorizes the formation of member-owned, democratically governed cooperatives and tasks the PREB with their regulation, ensuring compliance with operational, financial, and sustainability standards. The Act promotes the use of renewable energy sources such as solar and wind, aligning with Puerto Rico's broader goal of achieving 100% renewable energy by 2050. By fostering local ownership and resilience, Act 258-2018, represents a significant step toward energy democratization, though its success depends on effective implementation, regulatory clarity, and sustained community engagement.

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Commonwealth of Puerto Rico Laws	Description
Puerto Rico Energy Efficiency Policy Act, Act No. 33-2019	Act No. 33-2019 establishes a comprehensive legal framework to position energy efficiency as a central pillar of Puerto Rico's energy transformation strategy. Complementing Act No. 17-2019, this legislation mandates the development and implementation of enforceable energy efficiency standards across all sectors, with the goal of achieving a 30% reduction in energy consumption by 2040. It promotes public education, incentivizes the adoption of energy-efficient technologies, and supports funding mechanisms through public-private partnerships. The Act also requires ongoing monitoring and reporting to ensure transparency and accountability. By reducing energy demand, lowering consumer costs, and supporting environmental sustainability, Act 33-2019 plays a critical role in Puerto Rico's transition to a resilient, low-carbon energy future, though its success depends on effective implementation, stakeholder collaboration, and sustained public engagement.
Puerto Rico Energy Public Policy Act, Act No.17-2019	Act No. 17-2019, known as the Puerto Rico Energy Public Policy Act, establishes a comprehensive legal framework to transform the island's energy sector into a resilient, reliable, and sustainable system. The law mandates a transition to 100% renewable energy by 2050, with interim targets of 40% by 2025 and 60% by 2040, and prioritizes the integration of distributed generation, microgrids, and energy storage. It strengthens the regulatory authority of the Puerto Rico Energy Bureau (PREB), enhances consumer protections, and promotes energy efficiency and affordability. The Act also restructures the governance of the Puerto Rico Electric Power Authority (PREPA), aligns with the Integrated Resource Plan (IRP), and prohibits coal-based energy generation after 2028. By emphasizing decentralization, transparency, and environmental responsibility, Act 17-2019 serves as a cornerstone of Puerto Rico's long-term strategy to achieve energy independence and climate resilience.
Puerto Rico Emergency Moratorium and Financial Rehabilitation Act, Act No. 21-2016	Act No. 21-2016, enacted in response to Puerto Rico's escalating fiscal crisis, provided the government with emergency powers to manage its financial obligations while safeguarding essential public services. The law authorized the Governor to declare a temporary moratorium on debt payments for certain public entities, including the Government Development Bank (GDB), to prevent default and stabilize the island's finances. It prioritized the continuity of critical services such as healthcare, education, and public safety, and introduced legal mechanisms for debt restructuring and fiscal rehabilitation. While the Act was instrumental in averting immediate financial collapse, it drew criticism for undermining creditor confidence and delaying comprehensive reforms. Ultimately, it laid the groundwork for federal intervention through the enactment of PROMESA, which established a fiscal oversight board and a structured debt restructuring process.

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Commonwealth of Puerto Rico Laws	Description
Puerto Rico Energy Transformation and Relief Act, Act No.57-2014	Act No. 57-2014, known as the Puerto Rico Energy Transformation and RELIEF Act, marked a foundational shift in the island's energy policy by establishing a modern regulatory framework to address longstanding inefficiencies, high costs, and lack of transparency in the energy sector. The Act created the Puerto Rico Energy Bureau (PREB) as an independent regulatory body to oversee energy providers, enforce compliance, and promote accountability. It introduced reforms to the governance of the Puerto Rico Electric Power Authority (PREPA), mandated the development of integrated resource and energy efficiency plans, and laid the groundwork for transitioning to renewable energy sources. The legislation also emphasized consumer protection, rate transparency, and public participation, while encouraging infrastructure modernization and diversification of energy generation. As a cornerstone of Puerto Rico's energy reform, Act 57-2014 continues to guide the island's efforts toward a more resilient, affordable, and sustainable energy system.
Puerto Rico Financial Emergency and Fiscal Responsibility Act, Act No. 5-2017	Act No. 5-2017, known as the Puerto Rico Financial Emergency and Fiscal Responsibility Act, was enacted to provide the Government of Puerto Rico with the legal tools necessary to manage its fiscal crisis while ensuring the continuity of essential public services. The Act authorizes the Governor to declare a financial emergency and to take extraordinary measures, including the delegation of functions and the repeal of specific provisions of the 2016 Emergency Moratorium Act. It establishes a framework for prioritizing the allocation of limited resources to protect critical services such as healthcare, education, and public safety. Additionally, the Act includes a language supremacy clause, stipulating that in the event of a conflict between the English and Spanish versions of the law, the English version shall prevail.
Puerto Rico Incentives Code, Act No. 60-2019	Act No. 60-2019, known as the Puerto Rico Incentives Code, was enacted to consolidate and modernize the island's diverse tax incentive programs into a unified legal framework aimed at promoting sustainable economic development. By integrating prior statutes such as Acts 20 and 22, the Code streamlines compliance and administration while offering targeted tax benefits to key sectors including manufacturing, technology, renewable energy, tourism, agriculture, and export services. It provides reduced corporate tax rates, individual exemptions on passive income, and property and municipal tax relief, all tied to performance metrics such as job creation and capital investment. Designed to enhance Puerto Rico's global competitiveness, the Code seeks to attract investment, stimulate innovation, and foster local economic growth. However, its effectiveness depends on rigorous oversight, equitable implementation, and ensuring that the benefits translate into tangible value for the broader population.

Commonwealth of Puerto Rico Laws	Description
Puerto Rico Municipal Code, Act No. 107-2020	Act No. 107-2020, known as the Puerto Rico Municipal Code, represents a comprehensive legislative reform aimed at modernizing and streamlining municipal governance across the island. Enacted on August 14, 2020, the Code consolidates and updates numerous laws governing municipal administration into a single, cohesive legal framework, replacing outdated and fragmented statutes. It preserves the principle of municipal autonomy established under Act No. 81-1991, while introducing modernized provisions for organizational structure, fiscal responsibility, and administrative efficiency. The Code enhances transparency, simplifies regulatory compliance, and equips municipalities with tools to address contemporary governance and fiscal challenges. By fostering more accountable and responsive local governments, Act 107-2020 serves as a foundational instrument for strengthening public administration and promoting sustainable development throughout Puerto Rico.
Puerto Rico Net Metering Program Act, Act No. 114-2007	Act No. 114-2007 serves as a foundational policy in advancing renewable energy adoption across the island. It establishes a regulatory framework that enables consumers to generate electricity from renewable sources, such as solar or wind, to interconnect with the Puerto Rico Electric Power Authority (PREPA) grid, allowing them to offset consumption by feeding surplus energy back into the system. This mechanism not only provides financial incentives through energy credits applied to future bills but also promotes environmental sustainability, economic development, and energy resilience. By reducing reliance on fossil fuels and encouraging distributed generation, the Act supports job creation and innovation within the clean energy sector. However, to ensure equitable access and long-term viability, continued policy support is essential, particularly in addressing concerns about the potential devaluation of net metering benefits for vulnerable populations.

2.2.4 Commonwealth of Puerto Rico Rules & Regulations

Non-exhaustive list with a brief description of Commonwealth of Puerto Rico relevant regulations.

Table 11: Puerto Rico Energy Bureau Regulation

Puerto Rico Energy Bureau Regulation	Description
Regulation on the Standards of Ethical Conduct For Employees of the Puerto Rico Energy Commission And The Principles That Should Govern The Commissioners' Actions As Representatives Of The Commission Regulation No. 8542	Regulation No. 8542 establishes the ethical standards for employees and commissioners of the Puerto Rico Energy Commission. It outlines rules to prevent conflicts of interest, prohibits ex parte communications, and sets guidelines for professional conduct both during and outside of work.
Regulation on Adjudicative, Notice of Noncompliance, Rate Review and Investigation Procedures Regulation No. 8543	Regulation No. 8543 the Energy Bureau, establishes the procedural framework governing adjudicative proceedings, notices of noncompliance, rate reviews, and investigative processes under its jurisdiction.

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Puerto Rico Energy Bureau Regulation	Description
Regulation on Mediation and Arbitration Procedures of the Puerto Rico Energy Commission. Regulation No. 8558	Regulation No. 8558 establishes a comprehensive framework for the resolution of energy-related disputes through mediation and arbitration. It outlines procedural guidelines for voluntary mediation and binding arbitration, ensuring impartiality, confidentiality, and enforceability of outcomes.
Amendment to Regulation on Certification, Annual Fees, and Operational Plans for Electric Service Companies in Puerto Rico Regulation No. 8701	Regulation No. 8701 amends Regulation 8618 to refine the certification process, annual fee structure, and operational reporting requirements for electric service companies in Puerto Rico. It introduces clearer classifications for service providers, streamlines confidentiality procedures, and adjusts fee schedules based on company size and service type. The regulation also strengthens compliance mechanisms, including fines and certification revocation, and enhances transparency by requiring detailed operational and financial disclosures.
New Regulation on Rate Filing Requirement for the Puerto Rico Electric Power Authority's First-Rate Case Regulation No. 8720	Regulation No. 8720 establishes the procedural and substantive framework for the PREPA first permanent rate case. This regulation is a pivotal component in the transformation of Puerto Rico's energy sector, as it introduces a transparent, accountable, and equitable process for evaluating and setting electricity rates. By aligning with regulatory best practices and ensuring robust stakeholder participation,
Joint Regulation for the Procurement, Evaluation, Selection, Negotiation, and Award of Contracts for the Purchase of Energy and the Procurement, Evaluation, Selection, Negotiation, and Award Process for the Modernization of the Generation Fleet Regulation No. 8815	Regulation No. 8815, establishes a comprehensive regulatory framework governing the procurement, evaluation, negotiation, and awarding of contracts related to energy generation and infrastructure modernization in Puerto Rico. Administered by the Puerto Rico Energy Bureau, this regulation is designed to ensure that all contracting processes are conducted with transparency, consistency, and competitiveness, while safeguarding public interest. By fostering a level playing field and encouraging private sector participation,

Puerto Rico Energy Bureau Regulation	Description
Amendment to the Regulation on the Contribution in Lieu of Taxes (CELI) Regulation No. 8818	Regulation No. 8818 amends Regulation 8653 to align the CELI framework with changes introduced by Law 4-2016. It establishes updated procedures for calculating and distributing the CELI, introduces direct charges to consumers for CELI-related costs, and redefines the classification of municipal properties and services eligible for CELI coverage. The regulation also sets annual energy reduction targets for municipalities, outlines consequences for non-compliance, and details the process for suspending electric service due to unpaid excess consumption. Additionally, it mandates transparency through public reporting, creates mechanisms for dispute resolution, and introduces new rules for public lighting and mixed-use facilities.
Regulation of Integrated Resource Plan for the Puerto Rico Electric Power Authority, Regulation No. 9021	Regulation No. 9021 establishes the regulatory framework for the development, evaluation, and implementation of the Integrated Resource Plan (IRP) for the Puerto Rico Electric Power Authority (PREPA). The IRP serves as a long-term strategic roadmap to ensure the reliability, sustainability, and cost-effectiveness of Puerto Rico's electric power system. It mandates a comprehensive analysis of generation resources, demand forecasting, and infrastructure needs over a 20-year planning horizon, with updates every three years to reflect evolving technologies, market conditions, and policy objectives.
Regulation on Microgrid Development, Regulation No. 9028	Regulation No. 9028 establishes a comprehensive regulatory framework to facilitate the development, implementation, and operation of microgrids across the island. Aimed at enhancing energy resilience, sustainability, and affordabilityparticularly in areas vulnerable to grid instability or natural disastersthe regulation promotes the integration of renewable energy sources, supports diverse ownership models, and outlines clear licensing and compliance requirements. It also provides mechanisms for financial incentives and mandates inclusive stakeholder engagement.

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Puerto Rico Energy Bureau Regulation	Description
Regulation on the Review of Bills Issued by PREPA During Emergency Situations Regulation No. 9051	Regulation No. 9051 governs how customers can dispute electric bills issued during emergency situations, such as natural disasters or prolonged outages. It applies when customers are billed for energy not supplied by PREPA but generated through private generators. The regulation outlines informal and formal review processes, prohibits disconnection during disputes, and ensures timely resolution. It also clarifies that customers may object to bills from the emergency period of September–December 2017 even if they already paid or entered into payment plans, and extends the objection window accordingly.
Regulation on the Procedure for Bill Review and Suspension of Electric Service Due to Failure to Pay Regulation No. 9076	Regulation No. 9076 establishes the procedures for customers to dispute electric bills and outlines the steps utilities must follow before suspending service due to non-payment. It ensures due process, including informal and formal review mechanisms. It also mandates the use of a simplified summary procedure for disputes involving $5,000 or less and allows customers to opt into this process for larger disputes.
Regulation on Energy Cooperatives in Puerto Rico, Regulation No. 9117	Regulation No. 9117, establishes the legal and regulatory framework for the creation, governance, and oversight of energy cooperatives in Puerto Rico. This regulation supports the decentralization and modernization of the island's energy system by empowering communities to develop and manage localized energy solutions. It promotes democratic, member-owned cooperative structures, encourages the integration of renewable energy sources, and mandates compliance with operational, environmental, and safety standards..
Regulation for Performance Incentive Mechanisms Regulation No. 9137	Regulation No. 9137 establishes the framework for designing and implementing Performance Incentive Mechanisms (PIMs) for electric power service companies in Puerto Rico. It outlines the process for setting performance metrics, targets, and financial incentives or penalties to align utility behavior with public policy goals, including reliability, customer service, renewable integration, and energy efficiency. The regulation applies to all electric power service companies except electric cooperatives and includes provisions for annual reporting, compliance audits, public participation, and reconsideration or judicial review.

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Puerto Rico Energy Bureau Regulation	Description
Amendment to the Regulation on Certifications, Annual Fees, and Operational Plans for Electric Service Companies in Puerto Rico Regulation No. 9182	Regulation No. 9182 amends Regulation 8701 to align it with the changes introduced by Act 17-2019 and the amended Article 6.16 of Act 57-2014. It establishes a new framework for calculating and collecting the Energy Bureau's annual regulatory fee, which is now set at $20 million per fiscal year. The fee is prorated among all electric service companies, including PREPA, based on their gross annual revenues. PREPA is responsible for collecting the proportional share from other companies and remitting two payments of $10 million each to the Bureau annually. The regulation also updates definitions, clarifies reporting requirements, and prohibits companies from passing regulatory fees to PREPA through energy contracts. It reinforces transparency, accountability, and the Bureau's authority to audit and enforce compliance.
Regulation for Demand Response, Regulation No. 9246	Regulation No. 9246 establishes the regulatory framework for the design, implementation, and oversight of Demand Response (DR) programs across the island. These programs are intended to enhance energy efficiency, reduce system costs, and strengthen grid reliability by incentivizing consumers residential, commercial, and industrial to adjust their electricity usage during peak demand periods or in response to grid conditions. The regulation mandates that utilities develop tailored DR initiatives, offer participation incentives, and report performance metrics such as energy savings and customer engagement. It also promotes regulatory compliance through oversight mechanisms and enforcement provisions.
Regulation for Energy Efficiency, Regulation No. 9367	Regulation No. 9367 establishes a comprehensive framework to advance energy efficiency across the island. Anchored in principles such as equity, adaptability, and sustainability, the regulation mandates the development of three-year Energy Efficiency Plans that set measurable annual savings targets and outline strategies through 2040. It promotes the modernization of infrastructure, integration of renewable technologies, and active consumer participation, while ensuring equitable access to programs, particularly for vulnerable populations. The regulation also includes robust mechanisms for monitoring, reporting, and accountability to track progress and ensure transparency. By aligning with global best practices,

Puerto Rico Energy Bureau Regulation	Description
Regulation on Electric Energy Wheeling, Regulation No. 9374	Regulation No. 9374 establishes the regulatory framework for Electric Energy Wheeling, enabling independent power producers and retail electricity suppliers to transmit electricity through the existing utility grid directly to end users. This mechanism fosters competition in the energy market, supports the integration of renewable energy sources, and empowers consumers with greater choice and control over their energy supply. The regulation outlines fair and non-discriminatory access to the grid, establishes wheeling fees to ensure infrastructure sustainability, and includes consumer protections such as the right to return to the Provider of Last Resort in case of service failure.

2.2.5 Puerto Rico Electric Power Authority Regulation

Please be advised that the technical documents, manuals, and construction design standards originally issued under PREPA (Puerto Rico Electric Power Authority) regulations are undergoing revisions and updates by LUMA Energy, the current operator of Puerto Rico's electric transmission and distribution system. Notwithstanding these updates, any regulation that remains officially registered and published in the Puerto Rico Department of State's Regulation Registry continues to be valid and enforceable until formally repealed or superseded through the appropriate legal and administrative processes.

Table 12: Puerto Rico Electric Power Authority Regulation

Puerto Rico Electric Power Authority Regulation	Description
Installation of Conductors and Electrical Equipment Regulation, Regulation No 1744.	Regulation No. 1744 sets forth technical standards for the safe and efficient installation of electrical conductors and equipment. Aligned with national safety codes, it ensures proper materials, installation practices, and maintenance protocols to minimize risks and enhance system reliability. The regulation serves as a critical guide for professionals, promoting safety, energy efficiency, and long-term infrastructure resilience.

Puerto Rico Electric Power Authority Regulation	Description
Manual of Standards for Underground Residential Distribution, Regulation No 1875	Regulation No. 1875, establishes the Installation Manual of Standards for Underground Residential Distribution (URD), providing a comprehensive framework for the design, installation, and maintenance of underground electrical systems in residential areas. The regulation ensures safety, reliability, and regulatory compliance by standardizing technical specifications for materials, trenching, conduit systems, and transformer placement. It emphasizes energy efficiency, environmental sustainability, and future integration of renewable energy and smart grid technologies. As a critical reference for engineers, contractors, and inspectors, Regulation No. 1875 supports the development of resilient and modern electrical infrastructure across Puerto Rico.
Public Lighting Standards Manual, Regulation No. 1876	An older regulation governing street lighting, still technically in effect but considered obsolete. LUMA has requested its repeal because it conflicts with updated standards and responsibilities under the T&D OMA.[10]
Urban Distribution Standards Manual, Regulation No. 2367	The PREPA Urban Distribution Standards Manual, Regulation No. 2367, establishes comprehensive technical criteria governing the planning, design, construction, and maintenance of urban electrical distribution systems in Puerto Rico. It aims to ensure the safe, efficient, and reliable delivery of electric power within densely populated areas. The regulation outlines standardized configurations for high and low voltage connections, including Y (star) and delta systems, to optimize load balancing and energy distribution. It also prescribes detailed infrastructure specifications, such as pole types, transformer capacities, and conductor arrangements, tailored to urban load demands. Emphasis is placed on adherence to rigorous safety protocols aligned with national electrical codes to protect both personnel and the public.
Transmission Line Construction Standards Manual, Regulation No. 2124.	The PREPA Transmission Line Construction Standards Manual (Regulation No. 2124) establishes comprehensive technical criteria governing the planning, design, construction, and maintenance of the large power transmission lines that carry electricity over long distances. It includes rules to make sure the materials and structures used are strong and reliable, and that the work is done safely for both workers and the public.

[10] LUMA Energy, LLC. (2023, October 9). *Street Lighting System Design and Construction Manual* (Version 3) Exhibit 1, Case No. NEPR-MI-2020-0016.

Puerto Rico Electric Power Authority Regulation	Description
Certification of Construction Plans and Documents of the Electric Power Authority, the Water and Sewer Authority and the Department of Transportation and Public Works Necessary for the Issuance of Construction Permits to be Granted by the Administration of Regulations and Permits, Regulation No. 4435.	Establishes procedures for certifying PREPA, PRASA, and DTOP construction plans and documents to obtain permits from ARPE. Ensures technical compliance before permits are issued.
Manual for the Design and Construction of Grounding Grids for Substations and Equipment, Regulation No. 6533.	Provides engineering standards and safety requirements for grounding systems in substations and equipment, critical for reliability and protection.
Regulation for the Acquisition of Real Estate and Property Rights, Regulation No. 6955.	Sets processes PREPA must follow to acquire real estate or easements necessary for energy infrastructure.
Amendment to the Regulation for the Acquisition of Real Property and Property Rights, Regulation No. 7302.	Updates acquisition procedures for property rights, adjusting rules to improve compliance and speed of energy project execution.
Regulation for Interconnecting Generators with the Electric Distribution System of the Electric Power Authority and Participating in Net Metering Programs (Repeals Regulation No. 7544), Regulation No. 8915.	Governs interconnection of distributed generators (solar, DG) to PREPA's distribution grid and net metering participation. Repeals prior Regulation 7544.
Regulation of Easements for the Electric Power Authority Regulation No.7282	Defines how easements are established and used for PREPA infrastructure like transmission lines and substations.
Regulations for the certification of electrical installations (Repeals Reg. No. 5360), Regulation No. 7817.	Requires certification of electrical installations, repealing Reg. 5360, to ensure compliance with safety and operational standards.
Regulation for Interconnecting Generators with the Electric Transmission or Sub transmission System of the Electric Power Authority and Participating in Net Metering Programs, Regulation No. 8916	Establishes procedures for interconnection of larger generators to PREPA's transmission/sub-transmission systems, including technical and commercial requirements.
Regulations for the Granting of Energy Credit for Job Creation, Regulation 8371.	Provides criteria for granting energy credits to businesses that create jobs, encouraging economic development linked to energy consumption.
Regulations for the Granting of the Fixed Rate in Accordance with Law No. 69 of August 11, 2009, for Public Housing under the Ownership of the Public Housing Administration, Regulation No. 8278	Establishes a special fixed electricity rate for Public Housing Administration properties, as mandated by Law No. 69 (2009).

Puerto Rico Electric Power Authority Regulation	Description
General Terms and Conditions for the Supply of Electric Energy. (Repeals Reg. No. 7464. Amended by Regs. No. 8058 and 8366), Regulation No. 7982.	Sets PREPA's general conditions for providing electricity to customers. Repealed Reg. 7464, later amended by Regs. 8058 and 8366.
Installation of Conductors and Electrical Equipment Regulation, Regulation No 1744.	Provides standards for installing conductors and electrical equipment in Puerto Rico's grid.
Manual of Standards for Underground Residential Distribution, Regulation No 1875.	Establishes design and construction standards for underground residential distribution systems.
Public Lighting Standards Manual, Regulation No. 1876	Provides technical requirements for installation and operation of public street lighting.
Urban Distribution Standards Manual, Regulation No. 2367	Defines standards for urban distribution systems to ensure safety, uniformity, and efficiency.
Transmission Line Construction Standards Manual, Regulation No. 2124.	Technical requirements for the construction of transmission lines, covering design, materials, and safety.
Certification of Construction Plans and Documents of the Electric Power Authority, the Water and Sewer Authority and the Department of Transportation and Public Works Necessary for the Issuance of Construction Permits to be Granted by the Administration of Regulations and Permits, Regulation No. 4435.	Establishes procedures for certifying PREPA, PRASA, and DTOP construction plans and documents to obtain permits from ARPE. Ensures technical compliance before permits are issued.
Manual for the Design and Construction of Grounding Grids for Substations and Equipment, Regulation No. 6533.	Provides engineering standards and safety requirements for grounding systems in substations and equipment, critical for reliability and protection.

Table 13: Other Regulation

Other Commonwealth of Puerto Rico Regulation	Description
Infrastructure Planning Regulation (Planning Regulation 22), Regulation 4861	Establishes processes for long-term planning of infrastructure projects, including energy.
Joint Regulation for the Evaluation and Issuance of Permits Related to the Development, Use of Land, and Operation of Businesses, Regulation No. 9473	Provides a unified framework for permitting land development, construction, and business operations; streamlines permitting affecting energy projects.

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Other Commonwealth of Puerto Rico Regulation	Description
Regulation of New Competencies to Make Urban Development Viable (Planning Regulation No. 21), Regulation 4795	Defines planning authority competencies to facilitate urban development projects.
Regulation to Govern the Extraction, Excavation, Removal and Dredging of the Components of the Earth's Crust, Regulation No. 6916 as amended by Regulation No. 8191	Controls extraction of earth materials, relevant for construction of energy infrastructure.
Regulation for Access to Public Property for Telecommunications, Information and Pay TV Services, Regulation No. 9090	Sets rules for installing telecommunications infrastructure in public rights-of-way, which overlaps with utility corridors.
Regulation of Special permits for the use of Communities and Buildings Associated with Electronic Systems of Communities in State Sorest, Regulation Number 6769	Governs special permits for facilities in protected/state forest areas.
Regulation for the Processing, Evaluation and Designation of Strategic Projects, (Planning Regulation 37), Regulation No. 9012	Creates mechanisms to identify and expedite “strategic projects,” including energy infrastructure, with priority treatment.
Special Flood Hazard Areas Regulation. (Planning Regulation 13), Regulation No. 9238	Establishes development rules in flood-prone areas, important for siting substations, generation, and other energy assets.

2.2.6 Industry Codes & Standards

Non-exhaustive list with a brief description of relevant industry codes and standards.

Table 14: Industry Codes & Standards

Industry Codes & Standards	Description
Air Movement and Control Association International, Inc.	The Air Movement and Control Association International (AMCA) is a globally recognized nonprofit organization that develops and maintains performance standards for air movement and control equipment used in HVAC systems. AMCA supports manufacturers through a comprehensive framework that includes product certification, performance verification, challenge testing, and the publication of validated data. Its mission is to promote integrity, transparency, and technical excellence within the industry by ensuring that products are accurately tested and represented. Through its standards and certification programs, AMCA empowers manufacturers to demonstrate compliance, enhance product credibility, and support informed decision-making across the HVAC sector.

Industry Codes & Standards	Description
Aluminum Association	The Aluminum Association plays a central role in the North American aluminum industry, representing companies responsible for the majority of regional production and serving as the authoritative body for technical standards and data. Through its standards program, the Association oversees the registration of aluminum alloys, the development and maintenance of industry publications, and collaboration with academic and technical communities. Key resources include the Aluminum Design Manual (ADM), updated on a regular cycle to align with structural codes, and the Aluminum Standards & Data (AS&D), the industry's most comprehensive reference for alloy designations, chemical compositions, mechanical properties, and tolerances. These standards and publications are essential to ensuring consistency, quality, and innovation across the aluminum supply chain, supporting both regulatory compliance and technical advancement.
American Concrete Institute	The American Concrete Institute (ACI) develops and maintains a comprehensive suite of codes and standards that serve as foundational references for the design, construction, and maintenance of concrete structures. These guidelines address a broad spectrum of topics, including structural concrete design, repair methodologies, precast systems, seismic performance, and residential applications. Developed through a rigorous consensus-based process, ACI codes are recognized globally for promoting safety, durability, and structural integrity. Available in both print and digital formats, these standards support engineers, architects, and construction professionals in delivering high-quality, code-compliant concrete solutions across diverse project types.
American Institute of Steel Construction	The American Institute of Steel Construction (AISC) is a non-profit technical institute and trade association that serves as the leading authority on structural steel design and construction in the United States. AISC publishes the Steel Construction Manual and the Specification for Structural Steel Buildings, both of which are widely referenced in U.S. building codes and provide a unified framework for structural steel design using both Allowable Stress Design (ASD) and Load and Resistance Factor Design (LRFD) methodologies. The AISC standards encompass critical aspects of steel construction, including material classification, design documentation, erection methods, quality control, and contractual practices. Developed through industry consensus, these standards ensure consistency, safety, and efficiency in steel-framed structures. AISC also collaborates with government agencies, policymakers, and industry stakeholders to promote innovation, regulatory alignment, and best practices across the steel construction sector.

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Industry Codes & Standards	Description
American National Standards Institute	The American Institute of Steel Construction (AISC) is a non-profit technical institute and trade association that serves as the leading authority on structural steel design and construction in the United States. AISC publishes the Steel Construction Manual and the Specification for Structural Steel Buildings, both of which are widely referenced in U.S. building codes and provide a unified framework for structural steel design using both Allowable Stress Design (ASD) and Load and Resistance Factor Design (LRFD) methodologies.
American Society of Civil Engineers	Develops civil engineering standards and codes for infrastructure design, construction, and maintenance.
Association of Edison Illuminating Companies	Establishes best practices and technical guidelines for electric utility operations, including generation, transmission, and distribution.
ASTM International	Publishes voluntary consensus standards for materials, products, systems, and services across industries.
Building Industry Consulting Services International	Develops standards and provides certifications for information and communications technology (ICT) systems and infrastructure.
Construction Specifications Institute (CSI)	The CSI is a professional organization committed to enhancing the quality, clarity, and efficiency of the construction process through the development of industry standards and best practices. CSI is widely recognized for authoring foundational specification tools such as MasterFormat, UniFormat, and SectionFormat, which standardize the organization and communication of construction information across disciplines.
Greenhouse Gas Emissions Standards	The Greenhouse Gas Protocol (GHG Protocol) is the globally recognized standard for measuring, managing, and reporting greenhouse gas emissions across organizational operations, value chains, and climate initiatives. Developed through a multi-stakeholder process, it provides a consistent and comprehensive framework that enables organizations to produce transparent, credible, and comparable emissions inventories. By standardizing methodologies for tracking carbon and other greenhouse gases, the GHG Protocol supports informed decision-making, facilitates regulatory compliance, and underpins climate-related disclosures and sustainability strategies across sectors and borders.

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Industry Codes & Standards	Description
Illuminating Engineering Society	The Illuminating Engineering Society (IES) is the recognized technical authority in the field of lighting, dedicated to advancing the art and science of illumination through the development of industry standards and best practices. Established in 1906, IES publishes the Lighting Library®, a comprehensive collection of over 100 standards and recommended practices authored by expert technical committees. These standards guide lighting design, application, and performance across diverse sectors, ensuring quality, safety, and innovation in the built environment. Through its standards, publications, and educational initiatives, IES supports professionals, allied organizations, and the public in achieving excellence in lighting.
Insulated Cable Engineers Association	Develops technical standards for insulated cables used in electric power, control, and telecommunications systems.
Institute of Electrical and Electronics Engineers (IEEE)	The IEEE is a recognized professional organization dedicated to advancing technology across electrical engineering, electronics, computing, and related fields.
International Electrotechnical Commission Standards (IEC)	The IEC is a global standards organization responsible for developing and publishing international standards for electrical, electronic, and related technologies. Its standards span a wide range of sectors, including power generation, semiconductors, renewable energy, consumer electronics, and emerging fields such as nanotechnology and marine energy.
International Energy Conservation Code (IECC)	The IECC developed by the International Code Council, establishes minimum requirements for energy-efficient design and construction in residential and commercial buildings. First introduced in 2000 and updated every three years, the IECC reflects evolving technologies and best practices in energy conservation. It sets performance standards for key building systems including insulation, lighting, and HVAC to reduce energy consumption and support sustainability goals. Compliance with the IECC not only enhances building efficiency but also contributes to green building certifications such as LEED, improving environmental performance and market value.
International Organization for Standardization (ISO)	The ISO is an independent, non-governmental body that develops and publishes globally recognized standards to promote quality, safety, efficiency, and interoperability across industries.

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Industry Codes & Standards	Description
National Ambient Air Quality Standards (NAAQS)	The NAAQS established under the Clean Air Act by the U.S. Environmental Protection Agency (EPA), set legally enforceable limits on the concentration of six key pollutants in outdoor air to protect public health and the environment.
National Electric Code (NEC)	The NEC published by the National Fire Protection Association (NFPA), is a comprehensive standard that governs the safe installation of electrical wiring and equipment in residential, commercial, and industrial settings.
National Electrical Installation Standards (NEIS)	The NEIS are ANSI-approved benchmarks developed by the National Electrical Contractors Association (NECA) to define quality and workmanship for electrical construction.
National Electrical Manufacturers' Association (NEMA)	NEMA is a leading trade association representing over 450 manufacturers of electrical equipment and medical imaging technologies across North America.
National Electric Safety Code (NESC)	NESC is a consensus-based standard that establishes essential guidelines for the safe installation, operation, and maintenance of electric power and communication utility systems. Developed to protect both people and property from electrical hazards, the NESC addresses critical areas such as grounding, overhead and underground line installation, and utility worker safety protocols. Revised every five years to reflect technological advancements and industry practices, the NESC serves as a vital reference for engineers, electricians, and safety professionals, promoting consistent safety standards across the utility and construction sectors.
National Emission Standards for Hazardous Air Pollutants for Coal- and Oil-Fired Electric Utility Steam Generating Units (MATS)	MATS established under the National Emission Standards for Hazardous Air Pollutants (NESHAP), are EPA regulations aimed at reducing hazardous air pollutants (HAPs) from coal- and oil-fired electric utility steam generating units.
National Fire Protection Association Codes and Standards (NFPA)	The NFPA is a globally recognized authority dedicated to reducing the risks and consequences of fire, electrical, and related hazards through the development of over 300 consensus-based codes and standards. Its mission is to eliminate loss of life, injury, property damage, and economic disruption caused by such hazards.
PREPA Technical Bulletins and Manuals	PREPA Technical Bulletins are a group of thecnical documents and specifications that supplement PREPAS Regulations

Industry Codes & Standards	Description
Sheet Metal and Air Conditioning Contractors' National Association (SMACNA)	SMACNA is an internationally recognized trade association representing over 4,500 contractors across diverse markets, including HVAC, architectural and industrial sheet metal, energy management, and specialty fabrication. Accredited by ANSI as a standards-developing organization, SMACNA publishes widely adopted technical manuals and standards that guide construction and design practices globally. Through its Technical Resources Department, the association provides expert support to industry professionals and government agencies, while also offering members services in labor relations, legislative advocacy, safety, business management, and technical development.
Steel Door Institute (SDI)	SDI serves as a key authority in the steel door and frame industry, offering essential guidance on applicable building, fire, and safety codes. Its standards address topics such as fire-rated assemblies, accessibility, windstorm resistance, and energy efficiency, supporting code compliance throughout a building's lifecycle.
Telecommunications Industry Association	TIA is a leading ANSI-accredited organization responsible for developing standards that shape the telecommunications sector.
Underwriters Laboratories Standards (UL)	UL is a globally recognized safety science organization dedicated to advancing product safety through rigorous testing, certification, and standard development. UL standards are established through a consensus-driven process involving multidisciplinary technical committees, ensuring broad industry representation and expertise.

2.2.7 LUMA Proposed Constructions Codes, Standards, and Manuals

LUMA as Operator of the T&D System and under the provisions of the T&D OMA is on an on-going process of maintenance and revisions of all T&D System drawings, specifications, construction manuals, equipment diagrams and other technical documentation, records and standards for design and engineering, design standards, construction standards, and system mapping, among others. The following standards, specifications, and technical bulletins were developed by LUMA in accordance with its responsibilities under the Transmission and Distribution System Operation and Maintenance Agreement (T&D OMA), and in compliance with applicable laws, regulations, and industry practices. These documents govern all design and construction activities performed by LUMA or its contractors and are effective as of their approval dates unless otherwise noted. For third-party infrastructure intended for integration into PREPA's T&D system, previously published PREPA standards remain applicable until formally replaced. Some of the developed documents, manuals, specifications and drawings are:

Table 15: Standards

LUMA Manuals	Description
Overhead Electrical Distribution System Manual	Establishes the technical standards for the design and construction of overhead electrical distribution infrastructure in Puerto Rico. It includes requirements for poles, conductors, grounding, surge protection, wildlife protection, and compliance with NEC, NESC, and local regulations. It also outlines LUMA's authority and applicable legal framework.
Street Lighting System Design and Construction Manual	Provides updated requirements for the design and construction of street lighting systems in Puerto Rico. It includes standards for materials, installation heights, grounding, fuse protection, and luminaire configurations. The manual consolidates and updates multiple legacy standards
Transmission Line Structures Standard Configuration Bill of Materials	Consolidates all approved standard configurations and material lists for 38kV, 115kV, and 230kV transmission line structures. Includes legacy, standard, and custom structures, rigging details, and foundation specifications. Used as a reference for design, procurement, and construction of LUMA's transmission infrastructure.
Underground Electrical Distribution System Manual	Defines the design and construction standards for underground electrical distribution systems. It includes specifications for duct banks, manholes, cable types, grounding, and installation practices to ensure safety, reliability, and maintainability
Substation Ground Grid Design Standard	Establishes grounding design standards for LUMA substations. It covers design criteria, soil resistivity testing, grounding studies, equipment grounding practices, and safety requirements. The standard aligns with ANSI, IEEE, NEC, and other industry codes
4301.09.079 ASSY-1513 Wildlife Protection Equipment	Describes the specifications and application of wildlife protection equipment used in LUMA's electrical infrastructure. This equipment is designed to prevent animal-related outages and improve system reliability

2.2.8 Specifications

Luma has developed over 100 specifications and designs for infrastructure components. View the full list here.

2.2.9 Technical Bulletins

LUMA has published a series of technical bulletins that provide guidance on engineering standards, materials, and construction practices. You can view the full list here.

2.2.10 Others

Non-exhaustive list with a brief description of other relevant government policies and programs.

Table 16: Unites States Presidential Executive Orders

Presidential Executive Orders	Description
Executive Order 13990 – Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis *January 20, 2021*	Orders review and potential revocation of prior regulations inconsistent with climate goals; restores scientific integrity in policymaking. May have residual influence in pending regulations or agency reviews that feed into IRP.
Executive Order 14008 – Tackling the Climate Crisis at Home and Abroad *January 27, 2021*	Establishes the National Climate Task Force, pauses new fossil fuel leases on public lands, and integrates climate in foreign and domestic policy. Though some parts may be reversed, this EO shaped earlier carbon/climate policy direction; influences the historical trajectory that an IRP should consider.
Executive Order 14030 – Climate-Related Financial Risk *May 20, 2021*	Requires agencies to integrate climate-related financial risk into financial oversight, procurement, and planning. May impact cost of capital, risk assumptions, and screening for IRP (especially in relation to climate risk stress).
Executive Order 14057 – Catalyzing Clean Energy Industries and Jobs Through Federal Sustainability *December 8, 2021*	Directs the federal government to achieve net-zero greenhouse gas emissions by 2050 in operations; drives procurement and investment in clean energy, energy efficiency, and electrification. While focused on federal operations, it signals the federal direction and may influence incentives, funding programs, or expectations for carbon constraints that IRP should acknowledge.
Executive Order 14154 – Unleashing American Energy *January 20, 2025*	Encourages removal of regulatory impediments to energy and natural resource development; reverses certain climate-related and regulatory actions. Affects assumptions about regulatory risk, permitting burden, cost of compliance, and expansion of generation and resource options in IRP.
Executive Order 14156 – Declaring a National Energy Emergency *January 20, 2025*	Declares a national energy emergency, enabling federal agencies to use emergency authorities to expedite energy infrastructure, permitting, and production. May shorten lead times or override certain delays in permitting or siting of generation, affecting timeline assumptions in IRP.

Table 17: Governor of Puerto Rico Executive Orders

Executive Orders	Description
OE-2021-012 – LUMA Oversight Steering Committee	Orders the creation of a steering committee to oversee the public-private partnership contract with LUMA Energy.

Executive Orders	Description
OE-2021-024 – Infrastructure Emergency Declaration	Declares a broad infrastructure emergency (including energy) and establishes an expedited process for evaluating and approving reconstruction projects.
OE-2022-022 – Hydrogen as Renewable Energy	Recognizes hydrogen combustion as a renewable energy source in Puerto Rico.
OE-2024-014 – National Guard Support for Grid Emergencies	Activates the Puerto Rico National Guard to assist LUMA, Genera PR, PREPA, and PRASA during major incidents affecting the electric and water systems.
OE-2024-024 – Automatic Activation of Expedited Procedures (Act 76-2000)	Provides that any executive-declared emergency automatically triggers expedited permitting and contracting processes under Act 76-2000, without requiring new amendments.
OE-2025-002 – Expedited Permitting for Federally Funded Projects	Establishes streamlined permitting procedures for projects funded with federal dollars, including energy infrastructure, to accelerate reconstruction and modernization.
OE-2025-003 – Critical and Emergency Projects Fast-Track	Simplifies and expedites permitting for critical, strategic, and emergency projects, including energy-related ones.
OE-2025-005 – Creation of Energy Czar Office	Establishes the Office of the Energy Czar to oversee grid reconstruction, coordinate with federal agencies, and recommend structural changes, including operator transitions.
OE-2025-006 – Energy Transformation Working Group	Creates a working group to advise the Governor on energy diversification, federal funding use, PREPA debt restructuring, and regulatory reform.
OE-2025-016 – Expanding the State of Energy Emergency	Authorizes PREPA, LUMA, and agencies to take extraordinary measures to repair and modernize the grid; exempts many works from permitting and regulatory requirements; accelerates generation and transmission projects under emergency authority.
OE-2025-047 – Modify and Expand the Energy Emergency	Declares and expands Puerto Rico's energy emergency; directs agencies to accelerate approval of renewable and storage PPAs to capture federal investment tax credits; aligns local emergency measures with U.S. DOE emergency orders.

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Table 18: Puerto Rico Energy Bureau Administrative Procedures

Administrative Procedures	Description
In Re: Codes and Standards for Microgrid Compliance, Docket No. CEPR-MI-2018-0007	Establishes codes and compliance standards that microgrids must meet in Puerto Rico (safety, interconnection, operations, and consumer protections), complementing the Microgrid Regulation and enabling compliant deployment of community/commercial microgrids.
In Re: Implementing the Puerto Rico Electric Power Authority Integrated Resource Plan and Modified Action Plan, Docket No. NEPR-MI-2020-0012	Oversight docket for IRP implementation: tracks procurement tranches, project milestones, updates to modeling/assumptions, and Bureau directives to ensure execution of the approved IRP and its Modified Action Plan.
In Re: LUMA's Accelerated Storage Addition Program, Docket No. NEPR-MI-2024-0002	Proceeding to evaluate, authorize, and monitor a fast-track program for near-term battery energy storage additions aimed at improving reliability, reserving capacity, and integrating renewables consistent with IRP needs.
In Re: Optimization Proceeding of Mini grid Transmission and Distribution Investments, Docket No. NEPR-MI-2020-0016	Investigation/optimization of T&D investments to enable minigrid operation: prioritization of feeders, sectionalization, protection/communications, and resilience upgrades aligned with IRP "Creating a Resilient Grid."
In Re: Proposed Adoption Regulations on Renewable Energy Certificates and Compliance with Puerto Rico's Renewable Energy Portfolio, Docket No. (Not Available)	Rulemaking to adopt/clarify procedures for Renewable Energy Certificates (RECs), issuance/retirement, and RPS compliance reporting, supporting Act 17-2019 renewable targets and market transparency.
In Re: Proposed Amendment to Regulation No. 8543, Rules of Adjudication Procedure, Notices of Noncompliance, Review of Tariff Procedure and Investigations, Docket No. NEPR-MI-2019-0018	Amends the Energy Bureau's procedural rules to streamline adjudications, compliance notices, tariff reviews, and investigative processes, improving regulatory certainty for IRP-driven projects.
In Re: Proposed Regulation for the Evaluation and Approval of Agreements with Electric Power Service Companies, Docket No. (Not Available)	Rulemaking to establish criteria and processes for the Bureau's review/approval of agreements with Electric Power Service Companies (e.g., O&M, PPPs, asset services), ensuring alignment with the public interest and the IRP.
In Re: Regulation on the Development of Microgrids, Docket No. CEPR-MI-2018-0001	Foundational regulation defining microgrid classes (personal, cooperative, third-party), interconnection requirements, technical/operational standards, consumer protections, and market participation frameworks.
In Re: Revision of Regulation on Microgrid Development, Docket No. NEPR-MI-2023-0007	Updates the Microgrid Regulation to reflect lessons learned and grid modernization needs (e.g., islanding, interoperability, protection, and market interfaces) to scale resilient microgrids consistent with IRP goals.

Administrative Procedures	Description
In Re: Regulation for the Evaluation and Approval of Agreements Between Electric Service Companies, Docket No. NEPR-MI-2020-0014	Establishes codes and compliance standards that microgrids must meet in Puerto Rico (safety, interconnection, operations, and consumer protections), complementing the Microgrid Regulation and enabling compliant deployment of community/commercial microgrids.

Table 19: Other Programs

Programs	Description
Income Tax Regulations Proposed Amendment Section 45X, Advanced Manufacturing Production Credit	Federal tax credit for domestic production of eligible clean-energy components (e.g., solar/battery components). Relevant to IRP supply-chain assumptions, local manufacturing prospects, and project cost curves.
Low-Income Home Energy Assistance Program	Federal program that helps low-income households with energy bills and crisis assistance—affects affordability metrics and potential demand-side relief considered in IRP scenarios.
LUMA “Proposed” manuals, drawings, specifications, standards, and technical bulletins	Utility technical standards and field specifications (proposed/updated) for planning, protection, communications, interconnection, and construction.
PREPA Plan of Adjustment under Title III of the Puerto Rico Oversight, Management, and Economic Stability Act of 2016	Financial restructuring plan for PREPA establishing debt service terms and conditions.
Puerto Rico Grid Resilience and Transitions to 100% Renewable Energy Study (PR100)	DOE/NREL study providing system modeling, scenarios, and pathways to 100% renewables, key reference for IRP assumptions on technology mixes, transmission/storage needs, and reliability.
Solar Access Program	Program(s) to expand rooftop/community solar and storage access—often targeted to low- and moderate-income customers—supporting DER adoption considered in IRP distributed energy scenarios.
Temporary Assistance for Needy Families	Federal block grant supporting low-income families; informs socioeconomic/demand assumptions and energy-burden analyses in IRP equity considerations.
The Puerto Rico Energy Resilience Fund	Federal/territorial funding dedicated to deploying rooftop solar and storage for vulnerable customers.

2.3 Changes to Regulatory or Legislative Standards

On August 24, 2020, the Energy Bureau of the Puerto Rico Public Service Regulatory Board ("Energy Bureau") issued a Final Resolution and Order on the Puerto Rico Electric Power Authority's ("PREPA") Integrated Resource Plan ("IRP") under Case No. CEPR-AP-2018-0001 approving in part and rejecting in part PREPA's proposed IRP ("Approved IRP") and modifying the Action Plan originally proposed by PREPA, ordering the adoption and implementation of Modified Action Plan. Since August 24, 2020, the following changes of regulatory or legislative standards and rules have occurred..

2.3.1 Changes in Federal Law

Impacts of the Enactment of the One Big Beautiful Bill Act

This section documents the enactment of Public Law 119-21, commonly referred to as the *One Big Beautiful Bill Act* (OBBA), signed into law on July 4, 2025. OBBA introduces material changes to the federal statutory and regulatory framework governing energy policy, tax incentives, and grant programs. These changes are relevant to the planning assumptions, modeling inputs, and policy context of the 2025 Integrated Resource Plan (IRP), as required under Regulation No. 9021, which mandates the identification of "changes in law" that materially affect the planning environment.

OBBA repeals or restricts a broad set of federal tax credits and grant programs that were previously assumed to remain in effect throughout the IRP planning horizon. These include:

2.3.2 Repeal of residential and commercial energy efficiency incentives:

- §25D of the Internal Revenue Code (IRC), which established the Residential Clean Energy Credit, is repealed by OBBA §70506. This section previously allowed homeowners to claim a tax credit for solar PV, solar water heating, geothermal, wind, and battery storage systems.
- §179D IRC, the Commercial Building Energy Efficiency Deduction, is terminated by OBBA §70507[2]. This provision allowed deductions for energy-efficient lighting, HVAC, and building envelope upgrades.
- §45L IRC, the New Energy Efficient Home Credit, is terminated by OBBA §70508. This credit incentivized homebuilders to construct energy-efficient residential units.

2.3.3 Curtailment of clean electricity and manufacturing credits:

- §§45Y and 48E IRC, which provided ITC/PTC-equivalent support for clean electricity generation, are repealed by OBBA §§70512–70513.
- §45X IRC, the Advanced Manufacturing Production Credit, is phased down under OBBA §70514. This section supported domestic manufacturing of solar modules, batteries, and other clean energy components.

2.3.4 Termination or restriction of hydrogen and nuclear credits:

- §45V IRC, the *Clean Hydrogen Production Credit,* is terminated by OBBA §70511[6]. The IRP assumes this credit remains in place through 2032, but OBBA shortens the window to 2028.

- §45U IRC, the *Zero-Emission Nuclear Production Credit*, is restricted by OBBA §70510[7], which imposes Foreign Entity of Concern (FEOC) compliance requirements that may disqualify certain vendors or technologies.

2.3.5 Rescission of federal grant programs:

- The Inflation Reduction Act (IRA) and the Infrastructure Investment and Jobs Act (IIJA) grant programs for grid resilience, environmental justice, and GHG reduction, rescinded under Titles VI and VII.

Implications for IRP Planning Context

The enactment OBBA materially alters the federal statutory and regulatory environment that underpins multiple assumptions in the 2025 IRP. The following implications are noted for regulatory consideration:

2.3.6 Federal Incentive Assumptions

The 2025 IRP incorporates long-term federal support for clean energy technologies through provisions of the Internal Revenue Code as amended by IRA, including:

- Investment and production tax credits for clean electricity (§§45Y, 48E);
- Residential solar and storage incentives (§25D);
- Advanced manufacturing credits (§45X);
- Hydrogen production (§45V) and nuclear generation (§45U);
- Energy efficiency incentives (§§179D, 45L).

These provisions are embedded in the IRP's cost trajectories, financing structures, and adoption models for solar PV, wind, battery storage, hydrogen, nuclear, and energy efficiency programs. OBBA repeals or restricts each of these provisions. As a result, the assumptions regarding capital cost reductions, tax equity financing, and customer adoption incentives are no longer supported by current federal law.

2.3.7 Load Forecast and DER Participation

The IRP's load forecast incorporates reductions in net load due to distributed photovoltaic systems (DPV), behind-the-meter storage (BTM), and energy efficiency. These reductions are partially driven by the availability of §25D, §179D, and §45L incentives. OBBA repeals these provisions, which may reduce the economic attractiveness of DERs and efficiency measures. Consequently, the IRP's projected demand modifiers may overstate DER penetration and understate peak demand.

2.3.8 Capital Cost and Financing Structures

The IRP assumes that utility-scale solar, wind, and storage projects benefit from ITC/PTC-equivalent support (§§45Y, 48E) and manufacturing incentives (§45X), with financing structures that include accelerated depreciation and tax equity. OBBA repeals §§45Y and 48E and phases down §45X. It also modifies depreciation rules through §70509. These changes could undermine the cost assumptions and financing models used in the IRP's resource cost modeling and scenario design.

2.3.9 Scenario Design and Sensitivities

The IRP's core and supplemental scenarios assume continued federal support under the IRA and IIJA. OBBA eliminates these supports and introduces eligibility deadlines that bifurcate the resource landscape. The IRP does not currently reflect this bifurcation. Future scenario design may require the introduction of eligibility-based cases (e.g., full, partial, and no eligibility) to reflect the altered federal baseline.

2.3.10 Action Plan and Procurement Sequencing

The IRP's Action Plan outlines procurement and interconnection milestones without reference to OBBA's statutory deadlines. OBBA establishes transition windows for safe harbor (December 31, 2025), construction start (July 4, 2026), and placed-in-service (December 31, 2027). These deadlines may affect project eligibility for remaining federal incentives and should be considered in the sequencing of procurement and permitting activities.

2.3.11 Transmission and Distribution Planning

The IRP assumes federal grant support for grid modernization and resilience investments under the IRA and IIJA. OBBA rescinds these programs.[7] As a result, the funding assumptions for substation upgrades, feeder automation, and microgrid development may no longer be valid. These investments may now require repricing to reflect Commonwealth or ratepayer funding sources.

2.3.12 Changes In Local Law

Since August 24, 2020, the Government of Puerto Rico has approved 607 laws, of which the following directly impact the operation of the PREPA system.

Act for the Expedited Processing of Procedures Relating Exclusively to Federal Funds Granted to Agencies, Dependencies, Instrumentalities, Municipalities, and Public Corporations under the Community Development Block Grant for Disaster Recovery Program Act No. 71-2021

With Act No. 71-2021, the Government of Puerto Rico declared as the public policy of the Commonwealth of Puerto Rico to establish that all procedures related to the reconstruction phase with federal funds granted to individuals, agencies, dependencies, instrumentalities, municipalities and public corporations exclusively under the Community Development Block Grant for Disaster Recovery Program, FEMA, and ARPA will be governed by a flexible and expeditious process, to achieve the rapid construction of works and projects for the benefit of our citizens.

Public Policy in the Evaluation of Projects Subsidized with Federal Funds, Critical Projects, Strategic Projects, and Emergency Projects, (Act No. 118-2024)

Act No. 118-2024 amended various acts (Act 161-2009 and Act 107-2020) to address the need for a more expedited issuance of permits and reduce the cost of conducting business on our Island. These changes will spearhead Puerto Rico's sustainable progress in the 21st century in a responsible, orderly manner and a fair social, economic, and environmental balance process for projects subsidized with federal funds and those designated as critical, strategic, or emergency.

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Puerto Rico Energy Public Policy Act as amended, (Act No. 17-2019)

Act No. 17-2019 was amended by Act No. 1- 2025, to, among other things, extend the lawful use of coal-based power generation from 2028 until 2032, allowing the AES power plant in Guayama to continue operations. It also adjusts the Island's energy transition goals to reflect current energy conditions and ensure system reliability. Additionally, the amendment eliminated the interim renewable energy targets of 40% by 2025 and 60% by 2040, while maintaining the goal of achieving 100% renewable energy by 2050. Act No. 1-2025 recognizes the need to balance renewable integration with reliable, sustainable generation sources to meet current and future energy needs.

Public Policy on Energy Diversification by Means of Sustainable and Alternative Renewable Energy in Puerto Rico Act, as amended (Act No. 82-2010)

Act No. 82-2010 was created to, among other purposes, establish the standards to promote renewable energy generation under short, medium, and long-term mandatory goals known as the renewable portfolio standard (RPS). The RPS is the "mandatory percentage of sustainable renewable energy or alternative renewable energy required from each retail energy provider," as established in Act 82.[11] Notwithstanding the above, Act No. 1-2025 amended Act 82-2010. Act No. 1-2025 eliminated the interim renewable energy targets while maintaining the Renewable Energy Portfolio goal of achieving 100% by 2025. Act No.1-2025 also established the Government of Puerto Rico's public policy for replacing coal power plants or coal-based generation resources.

Act 82 defines "Sustainable renewable energy [as]…energy derived from the following sources:

- Solar energy
- Wind energy
- Geothermal energy
- Renewable biomass combustion
- Renewable biomass gas combustion
- Combustion of biofuels derived solely from renewable biomass
- Hydropower
- Marine and hydrokinetic renewable energy, as defined in Section 632 of the Energy Independence and Security Act of 2007 (Public Law 110-140, 42 U.S.C. § 17211)
- Ocean thermal energy

2.3.13 2025 Executive Orders

2025 Presidential Executive Orders

Unleashing American Energy Executive Order 14154 of January 20, 2025

[11] See Act 82, Section 1.4 (7), 12 LPRA §8121(7).

The Executive Order 14154 issued by the President of the United States emphasizes the need to unleash affordable and reliable energy to restore American prosperity and strengthen national security and establishes the policy aims to encourage energy exploration and production on Federal lands and waters, establish the United States as a leading producer of non-fuel minerals, protect economic and national security, eliminate the electric vehicle mandate, and promote consumer choice in goods and appliances. Agencies are directed to review and revise regulations that hinder domestic energy development. The order emphasizes efficient permitting processes and accurate environmental analyses. It also pauses the disbursement of funds for specific green initiatives and prioritizes national security by expediting reviews of liquefied natural gas (LNG) export projects, among others. The order emphasizes the need for a reliable, diversified, and affordable energy supply to support the nation's economy, national security, and technological innovation.

Declaring a National Energy Emergency Executive Order 14156 of January 20, 2025

Executive Order 14156, issued by the President of the United States, declares a National Energy Emergency. The order addresses the nation's inadequate energy supply and infrastructure, which are deemed insufficient to meet the country's needs and pose a threat to national security. The order outlines several actions to be taken, including Emergency Approvals for which Agencies are directed to use all lawful emergency authorities to facilitate the identification, leasing, production, transportation, refining, and generation of domestic energy resources; the Expediting Energy Infrastructure, for which Agencies are instructed to expedite the completion of authorized infrastructure, energy, environmental, and natural resources projects; Emergency Regulations, for which Agencies are ordered to use emergency regulations and permits to facilitate the nation's energy supply.

2025 Governor Executive Orders

“Executive Order of the Governor of Puerto Rico, Hon. Jenniffer González Colón, to modify and expand the state of energy emergency in Puerto Rico, align priorities with the national state of energy emergency and authorize the necessary measures to conduct the work of repairing the system and increasing power production capacity.” Administrative Bulletin No. OE-2025-016

With Executive Order OE-2025-016, the Governor of Puerto Rico modified and expanded the existing state of emergency of the Puerto Rico electric system, including the transmission and distribution systems, as well as generation and auxiliary infrastructure. In the order, the Governor emphasizes of goas under this order: obtaining and authorizing temporary short-term generation; performing major repairs to the generation units that operate using fossil fuels, such as Ultra Low Sulfur Diesel, natural gas and Bunker C with the support of said temporary generation; and advancing the timely construction of baseload plants and fast-track the reconstruction and modernization of the power grid. The Governor also ordered the acceleration of the repair and maintenance work on transformers, transmission and distribution lines, and electrical substations. Furthermore, the Governor exempted “totally and absolutely” to PREPA, LUMA Energy, Genera PR, AES and EcoEléctrica, from the requirement to apply or request any permits, consultations, authorizations, endorsements, comments, recommendations, certifications or collateral processes before any government agency for any work related to the repairs, reconstruction, and or substitution of the equipment or components of the Puerto Rico electric system. The Governor also directs the Energy Czar to supervise these activities.

“Executive Order of the Governor of Puerto Rico, Hon. Jenniffer González Colón, to establish the Office of the Energy Tsar.” Administrative Bulletin No.: OE-2025-005

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With Executive Order OE-2025-005, the Governor of Puerto Rico created the Office of the Energy Czar. Some of the primary responsibilities of the Energy Czar are to oversee, administer, and align the resources and objectives of Puerto Rico's energy public policy. This includes promoting communication between various government components and facilitating a swift response to energy challenges, leading the efforts to rebuild and modernize the electrical system, acting as a coordinator between Puerto Rico's government agencies, the Puerto Rico Electric Power Authority (PREPA), and federal agencies like FEMA, HUD, and DOE, and promoting efforts to add new baseload generation resources through public-private partnerships.

“Executive Order of the Governor of Puerto Rico, Hon. Jenniffer A. González Colón, to enforce provisions of Laws No. 18-2024, No. 119-2024, and No. 131-2024 and provide processes to expedite permits for federally funded projects, projects designated as critical or strategic, and emergency projects.” Administrative Bulletin No.: OE-2025-003

Executive Order OE-2025-003, issued by the Governor of Puerto Rico, establishes provisions to expedite permits for projects funded with federal funds, critical or strategic projects, and emergency projects. The executive order establishes as public policy the expedited processing of infrastructure projects financed with federal funds and projects designated as critical under PROMESA..

“Executive Order of the Governor of Puerto Rico, Hon. Jenniffer A. González Colón, to establish the working group for the simplification of permits in Puerto Rico.” Administrative Bulletin No.: OE-2025-002

Executive Order OE 2025-002, issued by the Governor of Puerto Rico, establishes a task force to simplify and expedite permits in Puerto Rico. The task is charged with conducting an comprehensive analysis of the permitting system to prepare and issue a report on the necessary changes to implement the public policy established in the executive order, including (1) designing and proposing systemic and structural reforms to the current permitting system; (2) identifying redundant and unnecessary processes; (3) recommending the revision or repeal of existing legislation and regulations that are inconsistent with this public policy; and (5) outlining the process for structuring, updating, and adopting a new Joint Permit Regulation that incorporates changes compatible with the public policy established herein.

“Executive Order of the Governor of Puerto Rico, Hon. Pedro R. Pierluisi, to declare an emergency of the infrastructure of Puerto Rico due to the damage caused by Hurricanes Irma and Maria, as well as the earthquakes that occurred in 2020, and activate the provisions of Act No. 76-2000, as amended”, Administrative Bulletin No. OE-2021-024, issued on March 25, 2021.

Through Executive Order OE-2021-024, the Governor of Puerto Rico declared an infrastructure emergency in response to the damage caused by Hurricanes Irma and María and the 2020 earthquakes. The executive order also stipulates that all reconstruction and mitigation projects be identified as critical by the Reconstruction Council created through Administrative Bulletin No. OE-2021-011 should be addressed expeditiously and urgently, ensuring compliance with applicable environmental regulations. The Governor also ordered the use of the expedited permitting process of Act 76-2000, as amended, for the construction and reconstruction of critical projects with special attention to reconstruction, modernization, and resiliency of the electric system, among others. This emergency declaration pursuant to Act 76-2000 has been extended through Administrative Bulletins Nos. OE-2021-069, OE-2022-021, OE-2022-050 (including the additional purpose of expediting development projects that allow meeting the RPS as well as projects microgrids, storage systems and ancillary services to generation), OE-2023-003, OE-2023-024, OE-2024-001, OE-2024-024.

2.3.14 Changes in Regulatory Standards

Regulation for Demand Response, of December 21, 2020, Regulation Number 9246 (Regulation No. 9246).

Regulation No.9246 establishes guidelines as required by Act No. 57-2014 and Act No. 17-2019 for the development of demand response programs to be submitted by the electric power service companies to the Energy Bureau for its review and approval. It also provides an overview and evaluation of the progress and effectiveness of the demand response plans.

Regulation for Energy Efficiency, of March 25, 2022, Regulation Number 9367 (Regulation No. 9367).

Regulation No. 9367 was designed and approved by the Energy Bureau following Act No. 17-2019 principles of efficiency, quality, continuity, adaptability, impartiality, solidarity, and equity to ensure that Puerto Rico reaches the 2040 goal of 30% (a goal previously in Act 17-2019 and Act 82, 2010) of energy efficiency by using an array of energy efficiency programs that will provide equitable access to energy efficiency for all customers. The regulation includes guidelines for developing, reviewing, approving, implementing, and overseeing energy efficiency programs.

Regulation on Electric Energy Wheeling, April 20, 2022, Regulation Number 9374 (Regulation No. 9374).

Energy Bureau-adopted Regulation No. 9374, by applicable law, to implement the energy wheeling mechanism in Puerto Rico. Regulation No. 9374 implements the system that allows an exempt business, dedicated to producing energy, to participate in the energy wheeling mechanism in Puerto Rico. This regulation shall apply to all companies offering electric services in Puerto Rico and to all companies intending to operate or provide electric services in Puerto Rico now or in the future.

2.3.15 Environmental Considerations[12]

The environmental impacts associated with electric system operations vary significantly between transmission and distribution (T&D) infrastructure and electric generation assets. While PR's extensive T&D network spans diverse ecological and urban landscape its environmental footprint is generally moderate and primarily associated with land use, vegetation management and localized construction impacts. In contrast, the operation of generation facilities presents more complex and significant challenges due to emissions, water usage, waste generation and fuel handling.

Electric generation resources are subject to a comprehensive framework of environmental laws and associated regulations at both federal and Commonwealth of Puerto Rico levels., These are enforced mainly by the United States Environmental Protection Agency (EPA) and the Department of Natural and Environmental Resources (DNER). Key areas of regulatory oversight include air quality, water quality, hazardous materials management and waste management, among others.

This section focuses on the environmental regulations most likely to influence the cost, operation and planning of generation resources over the 2025 IRP study horizon. Based on the information provided in the 2019 Integrated Resource Plan (2019 IRP) and currently best available information regarding PREPA's generation resources, and updated regulatory developments, the most impactful compliance

[12] This subsection was prepared with the information provided by Genera on June 6, 2025, and revised with the information sent by Genera in a communication dated October 17, 2025.

areas continue to be air emissions and water discharges These regulatory domains not only affect the operational viability of existing generation units but also shape the selection and design of future resources.

Therefore, the following analysis focuses on the current and emerging environmental compliance requirements relevant to the generation portfolio. It also outlines how these regulatory requirements are integrated into the IRP modeling framework to ensure that resources decisions reflects both regulatory obligations and environmental risk mitigation.

SO_2 NAAQS

The Clean Air Act[13] (as amended, the "CAA"), is a comprehensive federal law that addresses air quality and the stratospheric ozone layer and authorizes EPA to adopt, implement, and enforce regulations to reduce air pollutant emissions.

Pursuant to Section 109 of the CAA[14], the EPA promulgated regulations establishing primary and secondary NAAQS with respect to six principal pollutants, known as "criteria pollutants,"- namely, carbon monoxide (CO), particulate matter (PM), ozone (O_3), sulfur oxides (SO_x), nitrogen oxides (NO_x), and lead (Pb).[15] Areas that do not meet the NAAQS or that contribute to a nearby area that does not meet the NAAQS are referred to as "nonattainment areas."[16] Areas that meet the NAAQS and do not contribute to a nearby area that does not meet the NAAQS are known as "attainment areas." Areas that cannot be classified as meeting or not meeting the NAAQS are known as "unclassified" areas.

The NAAQS are to be achieved by the application of enforceable emission limitations and other control measures, means or techniques developed by the states and included in state implementation plans (SIP) which must be approved by EPA to be federally enforceable.[17]

Puerto Rico has a SIP approved by EPA[18], and as part of the implementation of this SIP, the Puerto Rico Environmental Quality Board (EQB) (which was merged into and is now the DNER) adopted a regulation titled the Regulation for the Control of Atmospheric Pollution (as amended, "RCAP")[19] which contains the requirements and prohibitions governing air emission sources in Puerto Rico.

In June 2010, EPA issued a final rule promulgating a new 1-hour primary Sulfur Dioxide (SO_2) NAAQS (2010 SO_2 NAAQS).[20] On January 9, 2018, EPA issued a final rule establishing initial air quality designations for certain areas in the United States for the 2010 SO_2 NAAQS, and made nonattainment designations for two areas in Puerto Rico: one in the area of San Juan, including the municipalities of Bayamón, Cataño, Guaynabo, San Juan and Toa Baja, and another in the area of Salinas.[21] This rule became effective on April 9, 2018, and triggered a requirement for the Puerto Rico Government to submit a SIP to satisfy nonattainment area planning requirements within 18 months of the effective date of the designation.[22]

In the 2019 IRP, PREPA identified the following PREPA generation units as being located in nonattainment areas for SO_2: Aguirre 1 ST, Aguirre 2 ST, Palo Seco 1 ST, Palo Seco 2 ST, Palo Seco 3 ST, Palo Seco 4 ST, San Juan 7 ST, San Juan 8 ST, San Juan 9 ST, San Juan 10 ST, Aguirre 1 CC,

13 42 U.S.C. §7401, et seq.
14 *Id*. §7409.
15 *See* 40 C.F.R. Part 50.
16 See 42 U.S.C. §7407(d)(1)(A)(i).
17 *See* 42 U.S.C. §7410.
18 *See* 40 C.F.R. Part 52, Subpart BBB.
19 Regulation 5300, approved on July 26, 1995, as amended.
20 *See* 75 Fed. Reg. 35520 (June 22, 2010).
21 *See* 83 Fed. Reg. 1098 (January 9, 2018). *See also* https://www3.epa.gov/airquality/greenbook/anayo_pr.html (data current as of April 30, 2025).
22 See 83 Fed. Reg. 1100.

Aguire 2 CC, San Juan 5 CC, San Juan 6 CC, Palo Seco GT 11, 12, Palo Seco GT21, 22, Palo Seco GT 31, 32, and Aguirre GT21, 22.

Since the 2019 IRP, the following regulatory activities or changes have occurred:

- On November 3, 2020, EPA took final action to find that Puerto Rico, among others, failed to submit a SIP to satisfy certain nonattainment area planning requirements under the CAA for the 2010 SO_2 NAAQS.[23] This action triggered a requirement for the EPA to promulgate a Federal Implementation Plan within 2 years after this finding if Puerto Rico has not submitted, and the EPA has not approved, the required SIP submittal.[24] To date, there is no record of a fully approved SIP for Puerto Rico for the 2010 SO_2 NAAQS non-attainment area.
- In March 2024, EPA issued a final rule establishing a more stringent primary annual standard for fine particulate matter (PM 2.5).[25] Area designation recommendations for Puerto Rico for regions in attainment or nonattainment areas under this standard have not been proposed or confirmed.
- On March 12, 2025, the EPA Administrator announced via news release that the agency is reconsidering the revised PM 2.5 NAAQS adopted by EPA on March 6, 2024, and would soon be releasing guidance to increase flexibility of NAAQS implementation, among others.

Based on information provided by Genera, Table 20 below identifies PREPA generation resources that are currently in nonattainment areas for SO_2:

Table 20: Summary of Genera's Units and Emission Regulatory Coverage

	Generation Units	Capacity (MW)	Fuel	SO_2 EPA Final Designation	MATS Affected	Carbon Emissions
Gas Turbine	San Juan GT-1	31	Natural gas, Diesel capable	Nonattainment	No	Yes
	San Juan GT-2	21	Natural gas, Diesel capable	Nonattainment	No	Yes
	San Juan GT-3	24	Natural gas, Diesel capable	Nonattainment	No	Yes
	San Juan GT-4	31	Natural gas, Diesel capable	Nonattainment	No	Yes
	San Juan GT-5	21	Natural gas, Diesel capable	Nonattainment	No	Yes
	San Juan GT-6	24	Natural gas, Diesel capable	Nonattainment	No	Yes
	San Juan GT-7	31	Natural gas, Diesel capable	Nonattainment	No	Yes
	Palo Seco GT-1	24	Natural gas, Diesel capable	Nonattainment	No	Yes
	Palo Seco GT-2	24	Natural gas, Diesel capable	Nonattainment	No	Yes
	Palo Seco GT-3	24	Natural gas, Diesel capable	Nonattainment	No	Yes
	Palo Seco GT-4	24	Natural gas, Diesel capable	Nonattainment	No	Yes
	Palo Seco GT-5	24	Natural gas, Diesel capable	Nonattainment	No	Yes
	Palo Seco GT-6	24	Natural gas, Diesel capable	Nonattainment	No	Yes

[23] 85 Fed. Reg. 69504 (November 3, 2020).
[24] *See id*. 69506.
[25] 89 Fed. Reg. 16202 (March 6, 2024).

	Generation Units	Capacity (MW)	Fuel	SO_2 EPA Final Designation	MATS Affected	Carbon Emissions
	Palo Seco GT-7	24	Natural gas, Diesel capable	Nonattainment	No	Yes
	Palo Seco GT-8	24	Natural gas, Diesel capable	Nonattainment	No	Yes
	Palo Seco GT-9	24	Natural gas, Diesel capable	Nonattainment	No	Yes
	Palo Seco GT-10	24	Natural gas, Diesel capable	Nonattainment	No	Yes
IPP units	AES Coal Plant	454	Coal	Attainment/ Unclassifiable	Yes**	Yes
	EcoEléctrica Plant	507	Natural Gas	NA	No	Yes

*For Aguirre, Costa Sur, Mayaguez, Yabucoa, Cambalache and Daguao no information was provided by Genera.

To support compliance with sulfur dioxide (SO2) air quality standards, particularly in designated non-attainment areas such as San Juan, Palo Seco, and Guayama, Genera has implemented an emission reduction strategy. This includes the use of ultra-low sulfur diesel (ULSD) on all its diesel-powered generation units, significantly reducing SO2 emissions compared to legacy fuels. In addition, fuel conversion projects are underway to transition several units to use natural gas as a primary fuel on several units, a fuel with negligible SO2 emissions. These actions are aligned with the Puerto Rico State Implementation Plan (SIP) for SO_2 compliance and are expected to contribute to achieving attainment of the 2010 1-hour SO_2 National Ambient Air Quality Standard (NAAQS). Further detail on emissions reductions, monitoring protocols, and compliance milestones is provided in the environmental modeling and regulatory compliance appendices of this 2025 IRP.

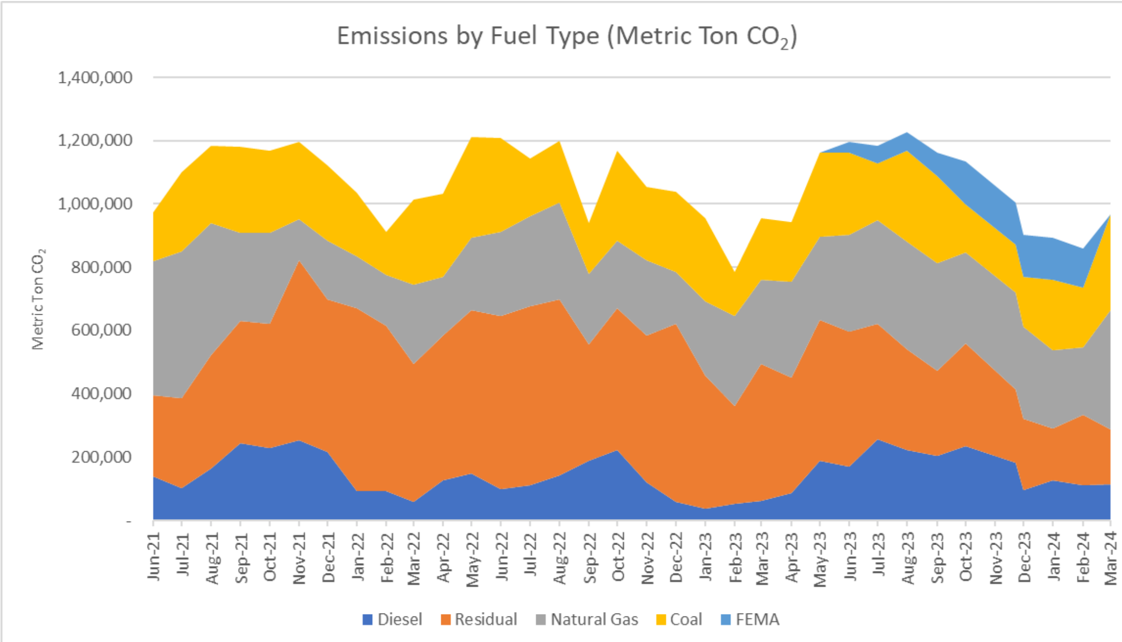
With respect to the PM2.5 NAAQS, based on information provided by Genera, the San Juan TM units (1-7) and the Palo Seco TM units (1-10) could be significant contributors of PM2.5 emissions.

Emission by Fuel Type

LUMA analyzed carbon dioxide (CO2) emissions from existing generation resources following the end of the 2019 IRP timeline through March 2024. Figure 2 below shows monthly totals ranging between 800,000 and 1.3 million metric tons of CO2, which reflect a substantial carbon footprint that requires compliance with the EPA Greenhouse Gas Reporting Program and Air Emission Title V permitting requirements.

Based on the information provided by Genera, the following table shows the amount of Emission by Metric Tons CO2 for each type of fuel used in Puerto Rico's fleet.

Figure 2: Emissions by Fuel Type for Generation Assets



The data indicates that residual fuel and coal are among the largest contributors, exceeding 600,000 metric tons of CO_2 per month.

The emissions profile in Table 20 shows monthly total emissions ranging between 800,000 and 1.3 million metric tons of carbon dioxide (CO2) from June 2021through March 2024, which reflects a substantial carbon footprint.

The data indicates that residual fuel and coal are among the largest contributors, exceeding 600,000 metric tons of CO2 per month.

Natural gas provides steady and significant contributions normally above 300,000 metric tons monthly, together with diesel fuel emissions under 200 metric tons monthly with spikes during years 2022 and 2023. Finally, the FEMA related category for emergency generation presents irregular peaks, reflecting short-term emergency generation during May 2023 to May 2024.

Mercury and Air Toxics Standards

Section 112 of the CAA[26] requires owners or operators of certain major sources to meet technology-based standards established by EPA to achieve the maximum degree of reduction in emissions of hazardous air pollutants (HAPs), identified under Section 112(b) of the CAA[27]. These standards are commonly referred to as maximum achievable control technology or "MACT" standards. The categories and subcategories of sources regulated under these provisions are listed in Section 112(c) of the CAA[28] and the regulations adopted by EPA establishing National Emissions Standards for Hazardous Air Pollutants (NESHAP).[29]

[26] 42 U.S.C. §7412.
[27] 42 U.S.C. §7412(b).
[28] 42 U.S.C. §7412(c).
[29] 40 C.F.R. Part 63.

In February 2012, EPA finalized a rule establishing standards to reduce air pollution from coal- and oil-fired power plants under Sections 111 and 112 of the CAA, referred to as the Mercury and Air Toxics Standards (MATS).[30] Under Section 111, the MATS rule revised New Source Performance Standards (NSPS) for new and modified facilities, including coal- and oil-fired power plants to include revised requirements for PM, SO_2 and NO_X and, under Section 112, the MATS rule revised the MACT standard to include emissions limitations for heavy metals, including mercury, arsenic, chromium, nickel, and acid gases from existing and new coal- and oil- fired electric utility steam generating units of a certain size.[31] In the 2020 IRP, PREPA informed that MATS affected multiple units. Specifically, Aguirre units 1 and 2 were not MATS compliant. Costa Sur units 5 and 6 were complying with MATS by fuel switching, operating on natural gas. Palo Seco unit 3 and San Juan unit 9 had PM emissions above the MATS limit and were run for reliability needs. San Juan Units 7-8 were designated as limited use units to meet the MATS emission limits, however, they also needed to comply with certain work practice standards.

Since the 2020 IRP, the following regulatory activities or changes have occurred. In May 2024, EPA published a final rule, effective July 8, 2024, revising the NESHAP for Coal- and Oil-Fired Electric Utility Steam Generating Units. This rule amended the filterable particulate matter (fPM) surrogate emission standard for non-mercury metal HAPs for existing coal-fired electric utility generating units and the fPM emission standard compliance demonstration requirements and mercury emission standard for lignite-fired electric utility generating units.[32]

On April 8, 2025, the President signed a Proclamation exempting certain stationary sources, identified in an annex to the Proclamation, from compliance with the revised NESHAP for Coal- and Oil-Fired Electric Utility Steam Generating Units issued in May 2024, for a period of 2 years. PREPA plants are not included in this list of exempted sources.

In June 2025, EPA announced a proposal to repeal the MATS rule's 2024 amendment and provided until August 11, 2025, for the public to provide comments.[33]

Based on information provided by Genera, all PREPA generation resources currently in operation are MATS compliant. Genera has also informed that there are no ongoing or planned corrective actions, including retrofits, components replacement, fuel switching, environmental upgrades, or unit retirement, to achieve MATS compliance. Genera has further informed that no PREPA unit is subject to an administrative or judicial action due to MATS compliance. However, Genera identified as capital projects related to MATS compliance the Continuous Emission Monitoring System (CEMS) replacement/repair project to repair/replace all components of the CEMS of Aguirre, Costa Sur, Palo Seco and San Juan facilities that were damaged due to numerous natural disasters that occurred in the last couple of years. Table 21 below details the status of each MATS-affected unit.

Table 21: Genera's Existing Units Subject to MATS

Generation Units	Fuel	MATS Compliance Status
Aguirre 1 ST	No. 6 Fuel Oil	Compliant
Aguirre 2 ST	No. 6 Fuel Oil	Compliant

[30] *See* 77 Fed. Reg. 9304 (February 16, 2012).
[31] *See id.*
[32] *See* 89 Fed. Reg. 38508 (May 7, 2024).
[33] *See* 90 Fed. Reg. 25535 (June 17, 2025).

Generation Units	Fuel	MATS Compliance Status
Costa Sur 3 ST	No. 6 Fuel Oil	This unit is currently not operating and will not be considered as a future generating resource in the IRP.
Costa Sur4ST	No. 6 Fuel Oil	This unit is currently not operating and will not be considered as a future generating resource in the IRP.
Costa Sur 5 ST	Natural Gas (No. 6 fuel oil capable)	Compliant
Costa Sur 6 ST	Natural Gas (No. 6 fuel oil capable)	Compliant
Palo Seco 1 ST	No. 6 Fuel Oil	This unit is currently not operating and will not be considered as a future generating resource in the IRP.
Palo Seco 2 ST	No. 6 Fuel Oil	This unit is currently not operating and will not be considered as a future generating resource in the IRP.
Palo Seco 3 ST	No. 6 Fuel Oil	Compliant
Palo Seco 4 ST	No. 6 Fuel Oil	Compliant
San Juan 7 ST	No. 6 Fuel Oil	Compliant
San Juan 8 ST	No. 6 Fuel Oil	Not in operation
San Juan 9 ST	No. 6 Fuel Oil	Compliant; not considered as a future generating resource in the 2025 IRP.
San Juan 10 ST	No. 6 Fuel Oil	This unit is currently not operating. Will not be considered as a future generating resource in the IRP.

Title V Operating Permits

Title V of the CAA[34] establishes an operating permit program for large stationary sources of air emissions that release pollutants into the air above a specified threshold, known as "major sources" and certain other sources referred to as "area sources." Responsibility for the Title V operating permit program in Puerto Rico was delegated by EPA to EQB, now DNER.

The RCAP establishes the requirements for the Title V permitting program. Table 22 below identifies the Title V operating permits for PREPA's fleet.

Table 22: Air Emission Permit Information

Plant	Permit Number	Permit Renewal Number
PREPA San Juan Steam Power Plant (San Juan)	PFE-TV-4911-1196-0016	PFE-TV-4911-65-0609-0214
PREPA Aguirre (Salinas)	PFE-TV-4911-63-0796-0005	PFE-TV-4911-63-0419-0235
PREPA Costa Sur (Guayanilla)	PFE-TV-4911-31-03-97-0021	PFE-TV-4911-31-0306-0429
PREPA Palo Seco (Toa Baja)	PFE-TV-4911-70-01196-0015	PFE-TV-4911-70-0319-0239
Aguirre Power Station	PFE-TV-4911-63-0212-0244	
Palo Seco Steam Power Plant	PFE-TV-4911-70-1196-0015	
South Coast Steam Power Plant (PREPA-Costa Sur	TV-4911-31-0397-0021	
San Juan Steam Power Plant	PFE-TV-4911-65-1196-0016	

[34] 42 U.S.C. §§7661-7661d.

Cambalache Combustion Turbine Plant	PFE-TV-4911-07-0897-0043	
Mayaguez Gas Turbines	TV-4911-63-1196-0014	
Daguao Turbine Power Block	PFE-TV-4911-19-0306-0447	
Jobos Turbine Power Block	PFE-TV-4911-30-1107-0991	
Vega Baja Turbine Power Block	(PFE-TV-4911-74-0106-0021	
Yabucoa Turbine Power Block	PFE-TV-4911-77-0707-0759	

Genera also informed that their operations are in substantial compliance with each of these air emission permits and none of the units are subject to enforcement actions.

As part of a proposed Consent Agreement and Final Order (CAFO) with the US EPA, Genera has submitted a compliance strategy addressing multiple CAA requirements related to its MobilePac units and stationary combustion turbines.

National Emissions Standards for Hazardous Air Pollutants (NESHAP)

To address the National Emissions Standards for Hazardous Air Pollutants (NESHAP) Stationary Sources under CAA Subpart YYY, which applies to stationary combustion turbines at major sources of hazardous air pollutants (HAPs), Genera proposed to the EPA to use 90% minimum load operating limitation as a surrogate parameter for demonstrating compliance with the Maximum Achievable Technology (MACT) standards. This approach is intended to establish a measurable threshold against which deviations are determined and reported. Currently, Genera can operate the MobilePacs only at a minimum load of 90%, limiting operational flexibility.

New Source Performance Standards (NSPS)

For the New Source Performance Standards (NSPS) Subpart KKKK, which governs emissions from stationary combustion turbines constructed or modified after February 18, 2005, PREPA and Genera acknowledged missed semi-annual compliance reports. To address this, PREPA and Genera have committed and have already fulfilled the following obligations under a Consent Agreement and Final Order with EPA: (1) prepare a parameter monitoring plan. (2) submit to EPA all past-due semi-annual compliance reports required under the NSPS Subpart KKKK and the NESHAP Subpart YYYY for the period commencing January 1, 2022, and (3) pay EPA a civil penalty of $145,000.00.[35]

Summary of Expenditures for Emissions under Permits for Generation

Table 23 below sets forth the information provided by Genera regarding the annual air emission payments to the DNER.

Table 23: Annual Air Emission Payments

Year	First or Second Payment	Cost	ACH Transfer Date
2022	Second	$750,000	12/26/2023
2023	First	$750,000	6/7/2024

[35] According to Genera letter from June 6, 2025, the amount is quoted as $145,000,00 [*sic*].

	Second	$750,000	12/23/2024
2024	First	$750,000	In Process

Genera has provided the emissions calculation information for Cambalache from 2019 to 2022 and is waiting on DNER to produce the annual emissions invoices to finalize transfer for 2024.

New Source Performance Standards for GHGs for Electric Generating Units

Section 111 of the CAA[36] requires owners or operators of certain new stationary sources to meet nationally uniform, technology-based standards for criteria pollutants established by EPA, called NSPS. The categories of sources covered by the NSPS are specified in EPA regulations under 40 C.F.R. Part 60. These regulations establish standards or emission guidelines that apply to power plants which, at the time of the 2020 IRP included standards of performance for fossil fuel-fired utility steam generating units, codified under 40 C.F.R. Part 60, Subpart Da, and NSPS for greenhouse gas emissions (GHG) for new, modified and reconstructed fossil fuel-fired electric steam generating units and stationary combustion turbines, codified under 40 C.F.R. Part 60, Subpart TTTT (Subpart TTTT).

Since the 2020 IRP, the following regulatory activities or changes have occurred. In May 2024, EPA issued a final rule establishing emission guidelines for GHG emissions from existing fossil fuel-fired steam generating units (EGUs), which include both coal-fired and oil/gas-fired steam generating EGUs (codified at 40 C.F.R. Part 60, Subpart UUUb, (Subpart UUUb); revisions to the NSPS for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion turbine EGUs in Subpart TTTT; and revisions to the NSPS for GHG emissions from fossil fuel-fired steam generating units constructed, reconstructed, or reconstructed after May 23, 2023 (codified under 40 C.F.R. Part 60, Subpart TTTTa (Subpart TTTTa)) [37] States are required to submit implementation plans within 24 months of the rule's publication.[38]

In June 2025, EPA issued a proposed rule to repeal all GHG emission standards for fossil fuel-fired power plants and, specifically, those under Subparts TTTT, TTTTa and UUUUb.[39] As an alternative, the EPA proposed to repeal a narrower set of requirements including emissions guidelines for existing fossil fuel-fired steam generating units, the carbon capture and sequestration/storage (CCS)-based standards for coal-fired steam generating units undertaking a large modification, and the CCS-based standards for new base load stationary combustion turbines.[40] The period to comment on this rule ended on August 7, 2025.[41]

According to information provided by Genera, EPA's proposal to eliminate the GHG emissions standards could reduce the regulatory burden on some PREPA units.

[36] 42 U.S.C. §7411.
[37] See 89 Fed. Reg. 39798 (May 9, 2024).
[38] *See id*.
[39] *See* 90 Fed. Reg. 25752 (June 17, 2025).
[40] *See id*. 25752.
[41] *See id*.

Clean Water Act Section

The Clean Water Act[42] (as amended, "CWA") is a comprehensive federal law governing water pollution. Section 301 of the CWA[43] prohibits the discharge of pollutants from point sources into waters of the United States, except as authorized under the National Pollutant Discharge Elimination System (NPDES) permit program. EPA has primary authority over this program in Puerto Rico. However, since states are required to issue water quality certificates in relation to the NPDES permits, in Puerto Rico, a water quality certificate from the DNER is also needed for the issuance of the NPDES Permit.[44]

PREPA's power plants can generate discharges associated with their process water systems, cooling water systems and storm water discharges. For these discharges, the power plants have to comply with NPDES permits with effluent limitations on various parameters, which include certain pollutants, flow, and temperature, among others.

The CWA authorizes EPA to establish effluent limitation guidelines and standards for different categories of facilities based on the degree of pollutant reduction attainable by the industrial category by application of pollutant control technologies.[45]

EPA has established these guidelines and standards applicable to steam electric power generating units, which are codified in 40 CFR Part 423. These guidelines and standards apply to discharges resulting from the generation of electricity utilizing fossil fuel, including discharges associated with both combustion turbines and steam turbines.[46] This regulation establishes standards for toxic metals, nutrients, and other pollutants in discharges of regulated facilities.

Electric generating plants are also likely to be subject to requirements relating to thermal discharges and cooling water intake structures. Section 316(a)[47] of the CWA authorizes EPA to issue a variance for effluent limitations for the control of the thermal component of a discharge.[48] Section 316(b)[49] of the CWA requires that NPDES permits for cooling water intake structures (CWIS) ensure that the location, design, construction, and capacity of these structures reflect the best technology available to minimize adverse environmental impacts.[50] These requirements apply to facilities designed to withdraw at more than two million gallons per day.[51]

Table 24 sets forth the information provided by Genera regarding the NPDES permits for the facilities operated by Genera.

Table 24: NPDES Permits

Facility	Permit Number	Issue Date	Expiration Date	Renewal Submission Dates

[42] 33 U.S.C. §§1251 *et seq.*
[43] 33 U.S.C. §1311.
[44] *See* 33 U.S.C. §1341; 12 LPRA 8002c(B)(7); Puerto Rico Water Quality Standards Regulation, Regulation 9677, approved April 30, 2025.
[45] *See* 40 C.F.R. Chapter I, Subchapter N.
[46] *See* 40 C.F.R. §423.10(a).
[47] *See* 33 U.S.C. §1326(a).
[48] See 40 C.F.R. §122.21(m)(6).
[49] *See* 33 U.S.C. §1326(b).
[50] *See* 40 C.F.R. Parts 122 and 125, Subparts I, J and N.
[51] *See* 40 C.F.R. Parts 125.81(a)(3), 125.91(a)(3) and 125.131(a)(3).

Palo Seco Power Plant	PR 0001031	January 12, 2016	March 31, 2021	September 2020
Costa Sur Power Plant	PR 0001147	June 6, 2018	August 31, 2023	March 2023
Aguirre Power Complex	PR 0001660	March 28, 2019	May 31, 2024	December 2023
PREPA San Juan	PR 0000698	June 6, 2018	August 31, 2023	March 2023

**Based on information provided by Genera, these permits are valid until EPA approves the renewal requests submitted by PREPA.

In May 2024, EPA issued a final rule to revise the technology-based effluent limitation guidelines and standards for the steam electric power generating point source category applicable to flue gas desulfurization wastewater, bottom ash transport water, combustion residual leachate, and legacy wastewater applicable to coal-fired power plants.[52]

In March 2025, EPA announced plans to revise the Steam Electric Power Generating Effluent Guidelines and Standards (40 CFR Part 423) by reconsidering how immediate relief can be provided from some of the requirements.

Based on information provided by Genera, the Palo Seco Power Plant, Costa Sur Power Plant, Aguirre Power Complex, and the San Juan Power Plant follow the steam electric power generating units effluent guidelines and standards, the requirements of Sections 316(a) and 316(b) of the CWA, and the Puerto Rico Water Quality Standards. Genera also informed of several current and planned projects to support compliance with NPDES permit renewals.

Table 25 sets forth the information provided by Genera regarding the compliance of the power plants it operates with significant regulatory requirements related to the NPDES permits for these facilities.

Table 25: Compliance Schedule for NPDES Permits

Facility	NPDES Renovation Submission EPA	WQC Submission ONER	DNER Compliance Plant Visit	WQC Public Notice by DNER	Coastal Zone Application (Planning Board)	Public Notice Final Permit (EPA)	Final Permit Granted
Palo Seco Power Plant	September 2020	May 2023	October 2023	September 2024	November 2024	TBD	Pending
Costa Sur Power Plant	March 2023	December 2024	June 2025	TBD	January 2024	TBD	Pending
Aguirre Power Complex	December 2023	January 2025	TBD	TBD	TBD	TBD	Pending
PREPA San Juan	March 2023	October 2024	March 2025	TBD	December 2023	TBD	Pending

Also, according to Genera, there are plants that cannot comply with their permits, and all NPDES Renewals have been submitted to EPA. The Water Quality Certificates (WQC) for the Palo Seco Power Plant, the Costa Sur Power Plant and the PREPA San Juan Plant have been submitted to DNER for evaluation. DNER has submitted the WQC for the Palo Seco Power Plant to EPA. According to their June 6, 2025, letter, Genera was planning to submit the WQC for the Aguirre Power Complex to DNER in June 2025.

[52] *See* 89 Fed. Reg. 40198 (May 9, 2024).

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Table 26 provided by Genera, shows the current and planned projects to support continued compliance with NPDES permit renovations.

Table 26: Current and Planned Projects for Continued NPDES Compliance

Facility	Project	Status
Palo Seco Power Plant	Multimedia Filter for the Wastewater Treatment Plant	100% Completed
	Travelling Screens 316 (b)	Procurement Process
Costa Sur Power Plant	Travelling Screens 316 (b)	Procurement Process
	Rehabilitation of Clarifications Units (Nautilus)	Project in Process
Aguirre Power Complex	Water supply project	75% Completed
	Travelling Screen 316 (b)	Procurement process
PREPA San Juan	Water Reuse Project	80% Completed
	Travelling Screen 316 (b)	Procurement Process

Genera has not identified any other proposed or promulgated environmental laws, rules, or regulations that may significantly impact resource plan decisions over the next 20 years.

Section 3:
Load Forecast

3.0 Load Forecast Overview

The 2025 IRP relies on multiple assumptions and forecasts. A key one of those forecasts is the load forecast. A load forecast estimates the expected level of customer demand and energy consumption over a particular period. For the 2025 IRP, LUMA developed a base load forecast, consisting of expected demand and energy consumption, and adjusted that forecast with a series of modifications related to expected: (1) additions of new distributed solar photovoltaics (DPV); (2) energy efficiency (EE); (3) distributed battery energy storage systems (DBESS); (4) electric vehicle (EV) charging loads; and (5) combined heat and power (CHP) facilities. LUMA refers to these modifications as “Load Modifiers.” LUMA also developed “low” and “high” load versions of the load forecast with and without Load Modifiers. The following subsections describe each of these forecast elements, how the respective forecasts were developed, and how they combine into the forecasts used in the 2025 IRP.

3.1 Base Load Forecast

One of the first things LUMA did when considering the load forecast for the 2025 IRP was to examine the load forecast from the 2020 IRP and compare it to actual energy and capacity sales over the last several years.

3.1.1 Historic Energy Sales

The total historical energy sales exhibited a compound annual growth rate of -1.24% between fiscal years (FY) 2009 and 2023. Some factors contributing to the decline in sales are:

- The recession began in Puerto Rico in FY2007; based on the official data provided by the Puerto Rico Planning Board (PRPB), the gross national product (GNP) measure for the economy experienced a compound annual growth rate of -0.57% from 2009 to 2023. The slight upward historic trend in fiscal years 2019, 2021, 2022, and 2023 upon interannual comparison can be attributable to the federal and local relief funds in response to Hurricane María and the effects of the restrictions implemented during the COVID-19 pandemic.

- The economic crisis escalated during FY2018 due to the significant devastation caused by hurricanes Irma and María, which affected Puerto Rico in September 2017. The hurricanes caused extensive damage to Puerto Rico's fragile power grid, resulting in a widespread outage. As a result of the extensive damage to the transmission and distribution grid, it took several months to restore service. Subsequently, there was a substantial decrease in total sales from 2018 to 2023 compared to FY2017.

- The island's population decline was consistent with the GNP. According to PRPB data, FY2018 recorded its lowest population count, a 4.1% decrease compared to FY2017. Since the 2020 census year, when modest economic recovery ensued, the population has remained stable.

- Analysts use cooling degree days (CDD) to calculate the energy needed for cooling and refrigeration. CDDs are a measure of how much (in degrees), and for how long (in days), outside air temperature was higher than a specific base temperature (typically 65 degrees). It is assumed that when the outside temperature is 65°F, people do not require heating or cooling to stay comfortable. Degree days differ between the mean daily temperature (high temperature plus low temperature divided by two) and 65°F. If the mean temperature is above 65°F, 65 is subtracted from the mean, and the result is CDD. If the mean temperature is below 65°F, 65 is subtract from the mean, and the result is heating degree days (HDD). The observed data used in the forecasts covers the fiscal years 2009 to 2023 and exhibits variations (up and down) in year-to-year comparisons. However, the trend shows a steady upward trend in the annual CDD, i.e., Puerto Rico demonstrates a systemic warming trend, with an average annual growth rate of 0.34% between 2009 and 2023.

- Hurricane Fiona hit Puerto Rico in September 2022, bringing winds that reached speeds of 100 mph and rain of up to 30 inches, which resulted in extensive flooding. Fiona caused severe damage to the electrical infrastructure of Puerto Rico, leading to a complete loss of power and a 5% decrease in overall sales compared to the prior fiscal year.

- Another factor that changed the demand pattern was the COVID-19 pandemic, specifically for residential consumption patterns.

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The 2020 IRP considered historic total sales data from FY2000 to FY2017. After Hurricane María hit in September 2017, there was a significant shift in sales trends. A compound annual growth rate of -1.48% was evident between 2017 and 2023.

The sales were divided into six customer classes: residential, commercial, industrial, agricultural, public lighting, and other authorities. Historically, the residential, commercial, and industrial classes accounted for 98% of the overall sales. Before 2020, the commercial class comprised roughly 47% of the total sales, while the residential class accounted for 36% and the industrial sector for 14%. The distribution of electricity consumption experienced a shift after the beginning of the COVID-19 pandemic, with the commercial class decreasing to 45%, the residential sector increasing to 41%, and the industrial class decreasing to 12%.

Residential GWh sales decreased by a compound annual growth rate of -0.06% from 2009 to 2023, and -0.20% from 2017 to 2023, before the effects of Hurricane María. Post-COVID-19, residential sales increased by an average of 6% in the fiscal years 2020 and 2021.

Conversely, the industrial and commercial classes experienced a compound annual growth rate of -4.68% and -1.17% between 2009 and 2023. In fiscal years 2020, 2021, 2022, and 2023, both customer classes experienced significant declines compared to FY2017. The recession in Puerto Rico's economy and the integration of distributed generation, specifically CHP generation, were the main drivers of these declines. Distributed generation enables customers to produce electricity, reducing their demand for grid-supplied energy. Figure 4 and Table 27 show historic energy sales for 2009 and 2023 by customer class.

Figure 3: Historical Annual Energy Sales by Customer Class

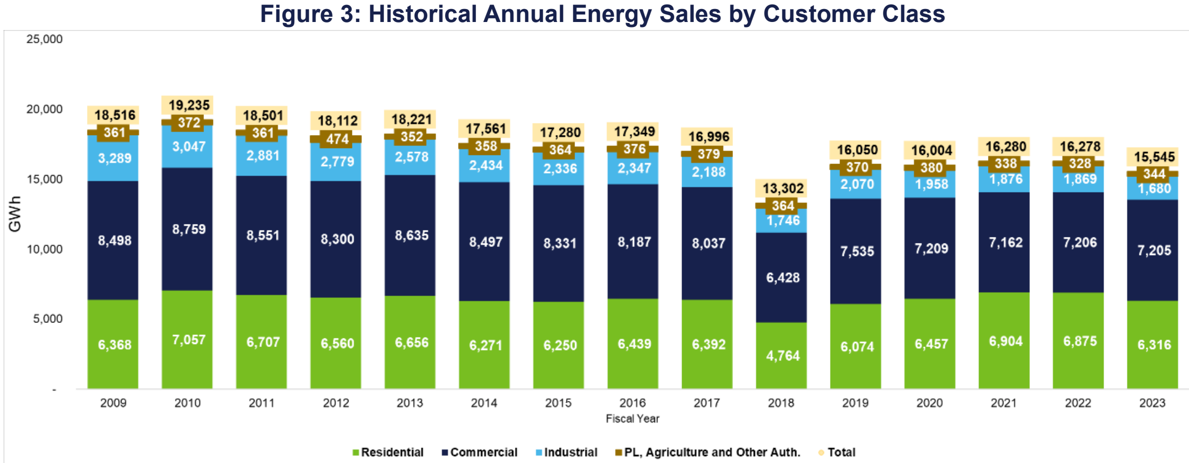

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Table 27: Historical Annual Energy Sales by Customer Class

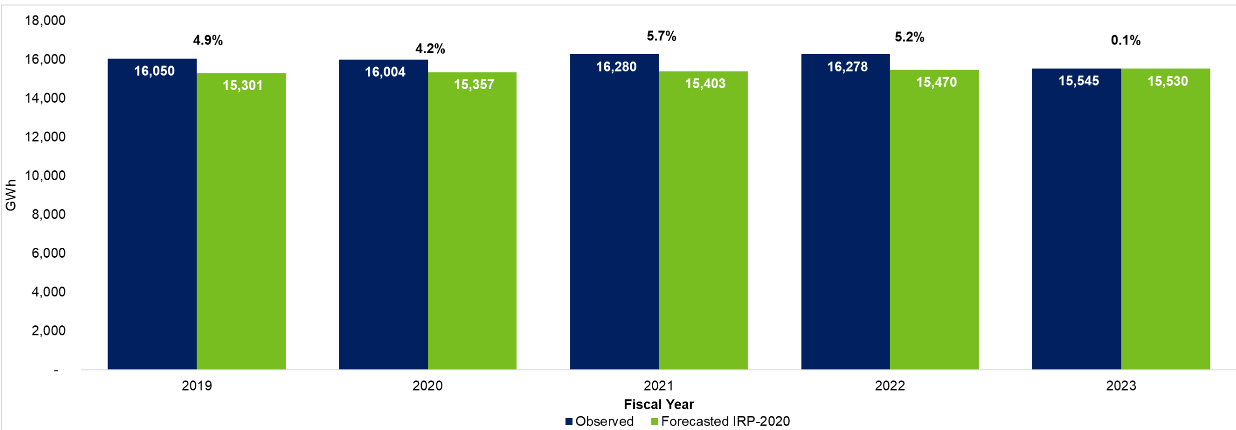
Fiscal Year	Residential (GWh)	Commercial (GWh)	Industrial (GWh)	Public Lighting (GWh)	Agriculture (GWh)	Others (GWh)	Total (GWh)
2009	6,368	8,498	3,289	274	31	57	18,516
2010	7,057	8,759	3,047	285	30	58	19,235
2011	6,707	8,551	2,881	281	29	51	18,501
2012	6,560	8,300	2,779	398	27	49	18,112
2013	6,656	8,635	2,578	268	27	56	18,221
2014	6,271	8,497	2,434	299	27	33	17,561
2015	6,250	8,331	2,336	302	26	35	17,280
2016	6,439	8,187	2,347	313	26	37	17,349
2017	6,392	8,037	2,188	319	26	35	16,996
2018	4,764	6,428	1,746	313	15	35	13,302
2019	6,074	7,535	2,070	304	26	40	16,050
2020	6,457	7,209	1,958	313	25	42	16,004
2021	6,904	7,162	1,876	281	25	32	16,280
2022	6,875	7,206	1,869	269	25	34	16,278
2023	6,316	7,205	1,680	284	22	37	15,545

3.1.2 Total Energy Sales - Historic Compared to 2020 IRP Forecast

The total historic sales at meter level compared to the 2020 IRP forecast exhibit an average increase year to year of 5.0% from fiscal years 2019 to 2023. However, FY2023 differs by 0.1% mainly due to the slowdown caused by Hurricane Fiona.

Figure 4 illustrates the year-by-year variance between the historic and forecast sales.

Figure 4: Historic and 2020 Integrated Resource Plan Forecasted Energy Sales at Meter Level



3.1.3 Total Generation – Historic

The total gross generation has been experiencing a decline directly proportional to the decrease in sales. The data shows a compound annual growth rate of -1.56% from 2009 to 2023 and -1.74% from 2017 to 2023. Although there was a significant rise in exporting from distributed generation, the interannual comparison in the post-COVID years demonstrated a slight rise in generation, except in the fiscal year 2023, attributed to Hurricane Fiona's impact.

Historically, fossil fuels have been the primary source of energy generation. The proportion of oil-based production experienced a significant decline, decreasing from 70% in fiscal year 2009 to 46% in fiscal year 2023. Furthermore, there was a substantial rise in natural gas production, from 15% in fiscal year 2009 to 36% by 2023. Coal production shows a consistent percentage change over the specified period. Renewable energy production began in the fiscal year 2013, and its contribution level has been constant over the past five years. Figure 5 shows the historical generation by source, and Table 28 shows the gross and net generation.

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Figure 5: Historical Gross Energy Generation by Source

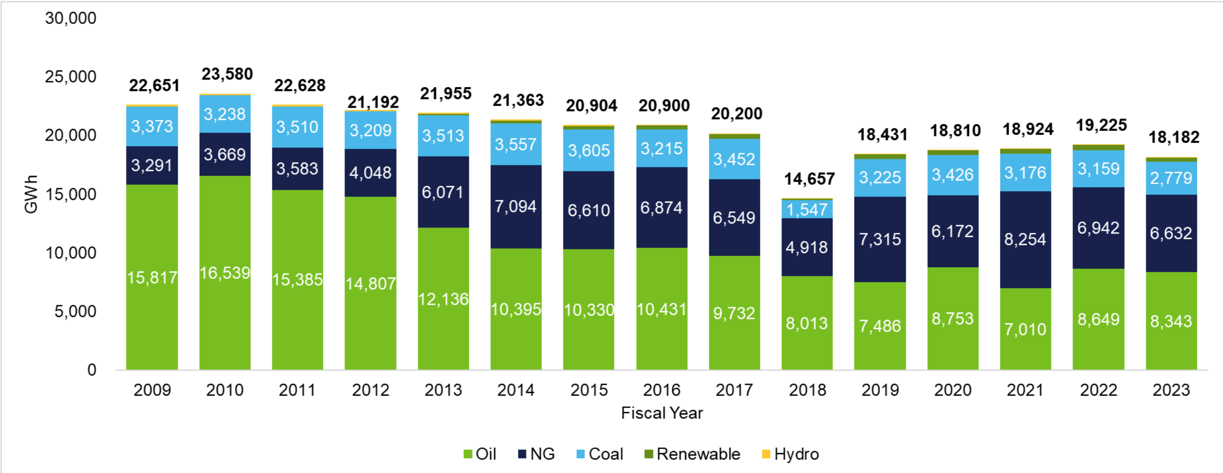


Table 28: Historic System Level Energy Generation

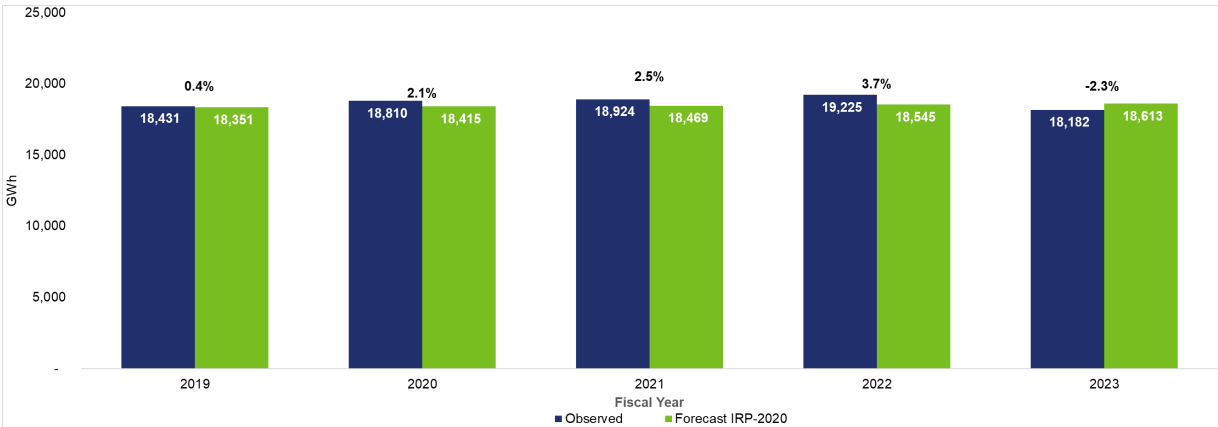
Fiscal Year	Gross Energy Generation (GWh)	Net Energy Generation (GWh)
2009	22,651	21,763
2010	23,580	22,562
2011	22,628	21,636
2012	22,192	21,204
2013	21,955	21,009
2014	21,363	20,508
2015	20,904	20,107
2016	20,900	20,113
2017[53]	20,200	19,449
2018	14,657	14,039
2019	18,431	17,753
2020	18,810	18,174
2021	18,924	18,289
2022	19,225	18,536
2023	18,182	17,568

[53] September 2017: The system was affected by Hurricanes Irma and María.

3.1.4 Gross Generation - Historic and 2020 IRP Forecast

The average annual variance between the historic and 2020 IRP forecast gross generation for 2019–2023 is less than the registered sales at the meter level. The observed value in FY2023 was the only year the expected value was lower than the historic, with an average variance of 1.3%. Figure 6 shows the comparison between the two.

Figure 6: Historic and 2020 IRP Gross Generation Forecast (GWh)



3.1.5 Historic Peak Demand

The coincident peak demand typically occurred between 8 p.m. and 10 p.m. The peak demand reached its historic high of 3,385 MW on September 1, 2005, during the fiscal year of 2006. The peak demand has decreased since the record high was achieved, with the lowest recorded at 2,771 MW in the fiscal year 2019. It rose after the lowest peak demand in the previous 23 years. Since the fiscal year 2023, it has been comparable to the four fiscal years that preceded 2019.

The integration of distributed generation systems does not impact the peak demand, as customers shift to using electricity from the electrical grid once the renewable sources are depleted at nightfall, especially during peak demand periods. Table 29 lists the historical coincident system peak demand for 2009 to 2023.

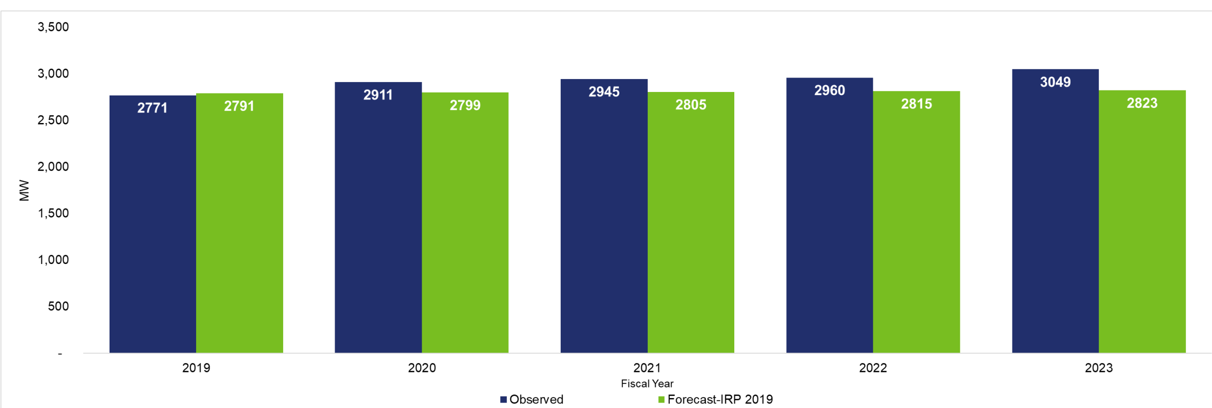
Table 29: Historical Coincident System Peak Demand

Fiscal Year	Peak Demand (MW)
2009	3,351
2010	3,404
2011	3,406
2012	3,303
2013	3,265
2014	3,159
2015	3,030
2016	3,080
2017	3,087
2018	3,060
2019	2,771
2020	2,911
2021	2,945
2022	2,960
2023	3,049

Peak Demand: Historic and Approved 2020 Integrated Resource Plan

In all fiscal years, except 2019, historic peak demand exceeded the anticipated peak demand. Figure 7 compares historic and peak demand from the 2020 IRP forecast.

Figure 7: Historic and IRP Forecasted System Peak Demand



3.1.6 Load Forecast Analysis

In collaboration with Guidehouse (GH), LUMA conducted a project to improve the demand forecasting process by considering the post-2017 changes in our customers' consumption patterns and achieving accurate forecasts. The load forecast for the primary classes was developed using the same methodology as the 2020 IRP, considering monthly observations from 2011 to 2023. The analysis focused on the same exogenous variables (macroeconomic) and incorporated additional variables to explain the recent changes in sales. The selected models, which will be described later, were comparable to the ones utilized for the PREPA fiscal plan, with some adjustments made to the parameters affecting the selected exogenous variables. Furthermore, additional variables were incorporated into the residential and industrial models.

The December 2023 model update includes recent observed data remediated to remove outliers caused by unusual events. This load update has revealed a notable change in sales patterns in residential and industrial classes. The statistical analysis indicates that the rise in temperature may be the primary driver in the residential class. However, the industrial sector experienced a substantial downturn after October 2022.

The forecasting approach comprises the following steps:

- Update Monthly Sales Forecast: Econometric regression model testing is conducted for the primary customer classes (residential, commercial, and industrial), while monthly sales forecasts for secondary customer classes (agriculture, public lighting, and other authorities) are integrated using different methodologies.
- Construct Class Demand Profiles: Hourly rate-class data extracted from historic rate-class load studies are utilized to construct hourly demand profiles for each customer class, covering the period from the fiscal year 2009 to the fiscal year 2022.
- Construct Hourly Puerto Rico-Level Forecast: By applying customer class demand profiles to the base forecast, hourly class demands for Puerto Rico are projected for all forecast years spanning fiscal years 2024 to 2044.
- Develop High/Low Forecast Scenarios: Alternative high and low scenarios address forecast uncertainties. These scenarios account for variations in macroeconomic forecasts, monthly average temperature conditions, and the timing of historic annual peaks. Macroeconomic variability is sourced from Moody's Analytics Economic Forecast and Historical Database.
- Transmission Planning Area Allocation: The hourly Puerto Rico-level scenario forecast is allocated among the eight transmission planning areas (TPAs) based on recent historic customer class sales data from fiscal year 2022 within each TPA.

3.1.7 Update Base Monthly Sales Forecast

Model Selection

As determined by regression testing, models that included additional macroeconomic variables did not outperform those selected for the Fiscal Plan. Adjustments to the 2023 Fiscal Plan forecast model were made in December 2023 and applied to improve the predictive accuracy of LUMA's load forecast. These revisions integrate additional exogenous variables to adapt to recent shifts in energy consumption patterns. The selected models were re-estimated using historic data from FY2011 to FY2024. Both commercial and residential models include variables addressing temperature impacts on consumption.

The macros provided by FOMB in March 2023 were employed in the IRP. They were the same ones utilized in the PREPA fiscal plan.

Residential Sales Model

The selected model estimates monthly residential energy sales as a function of monthly binary variables, CDD, population, and the effects of COVID-19. Multiple terms are employed to identify different shifts in consumption patterns attributed to COVID-19. The initial COVID-19 term assesses impacts during the first winter after the pandemic outbreak. The subsequent two terms, incorporating the post-COVID-19 variable, capture the interactive effects of elevated temperatures during the summer months from 2020 onwards. Recognizing the historic similarity in temperature conditions and consumption levels between May and October, these terms are consolidated into a single term to simplify the model.

$$
\begin{aligned}
y_t = \sum_{m=1}^{M=12} \beta_{1,m} month_{m,t} + \beta_2 CDD_t + \beta_3 Pop_t + \beta_4 COVIDwin_t \\
+ \sum_{m=6}^{M=9} \beta_{5,m} month_{m,t} \cdot post2019_t \cdot CDD500_t + \beta_6 month_{m\epsilon(5,10),t} \cdot post2019_t \cdot CDD500_t + \varepsilon_t
\end{aligned}
$$

Where:

$COVIDwin_t$ = A variable equal to one in the period beginning November of the calendar year 2020, running through to the end of April 2021, and zero otherwise. This captures the impact of COVID-19 on consumption in the winter after its emergence.

$post2019_t$ = A variable equal to one in calendar years 2020 through 2023, declining by 0.2 each May (beginning in May of calendar year 2024) until it reaches zero in May of calendar year 2028, and zero otherwise. As indicated by the monthly interaction and the subscripts on the associated summation, this applies only from May through October of each year (i.e., it takes a value of zero from November through April).

$CDD500_t$ = A variable equal to the difference between historic (or forecast) CDD and 500. The average weather in the months this is applied (via the interaction with the monthly binary and its associated summation subscripts)—June through October—CDD is, on average, consistently higher than 500. This variable attempts to better apply some weather sensitivity to the modeling.

$month_{m\in(5,10),t}$ = A variable equal to one if the month of sample is either the fifth or the 10th month of the calendar year (May or October), and zero otherwise. That is, the parameter associated with the group of variables that begins with this one captures the post-2019 temperature-sensitive "bump" to residential consumption for May and October. The model assumes that this relationship is the same for May and October.

The residential sales forecast reflects a -0.68% compound annual growth rate from fiscal year 2024 to 2044, higher than the compound reduction from 2009 to 2023.

Commercial Sales Model

The selected model estimates monthly commercial energy sales as a function of monthly binaries, CDD, interactions of CDD and monthly indicators, and GNP.

$$y_t = \sum_{m=1}^{M=12} \beta_{m,1} month_{m,t} + \sum_{m=1}^{M=12} \beta_{m,2} month_{m,t} \cdot CDD_t + \beta_3 CDD_t + \beta_4 GNP_t + \beta_5 COVIDCOMtrans_t + \varepsilon_t$$

Where:

GNP_t = A 12-month moving sum of the GNP. This monthly series is derived from an annual series provided by the PRPB, supplemented (as necessary) by the FOMB.54

$COVIDCOMtrans_t$ = A variable equal to one in March, April, and May of 2020, and zero otherwise.

The forecast shows a compound annual growth rate of -0.33% from fiscal year 2024 to 2044, less than the historic data between fiscal years 2009 and 2023.

Industrial Sales Model

The selected model estimates monthly industrial energy sales as a function of monthly binaries and GNP.

$$y_t = \sum_{m=1}^{M=12} \beta_m month_{m,t} + \beta_2 GNP_t + \beta_3 indBinary_t + \varepsilon_t$$

Sales forecasts demonstrate a compound annual growth rate of 1.03% from 2024 to 2044.

3.1.8 Exogenous Variables

Gross National Product Forecast

Commercial and industrial sales are forecasted using GNP. The observed data from fiscal year 2001 to 2021 indicates a compound annual growth rate of -0.69%, whereas the forecast period from 2022 to 2044 showed a decrease of -0.32%. Nevertheless, a year-by-year comparison of the forecast indicates that the Puerto Rico economy will experience a rebound from fiscal 2026 to 2029, mainly due to federal funding for restructuring the damaged infrastructure impacted by several natural events after September 2017. After FY2030, the GNP exhibits a slight downslope with a year-to-year average decline of ~0.6%. The observed and forecast GNP before the year in which the recession commenced are depicted in Figure 8.

[54] The annual series is converted to monthly by dividing the year-over-year (fiscal years) change in GNP by 12 and applying this increment in each month.

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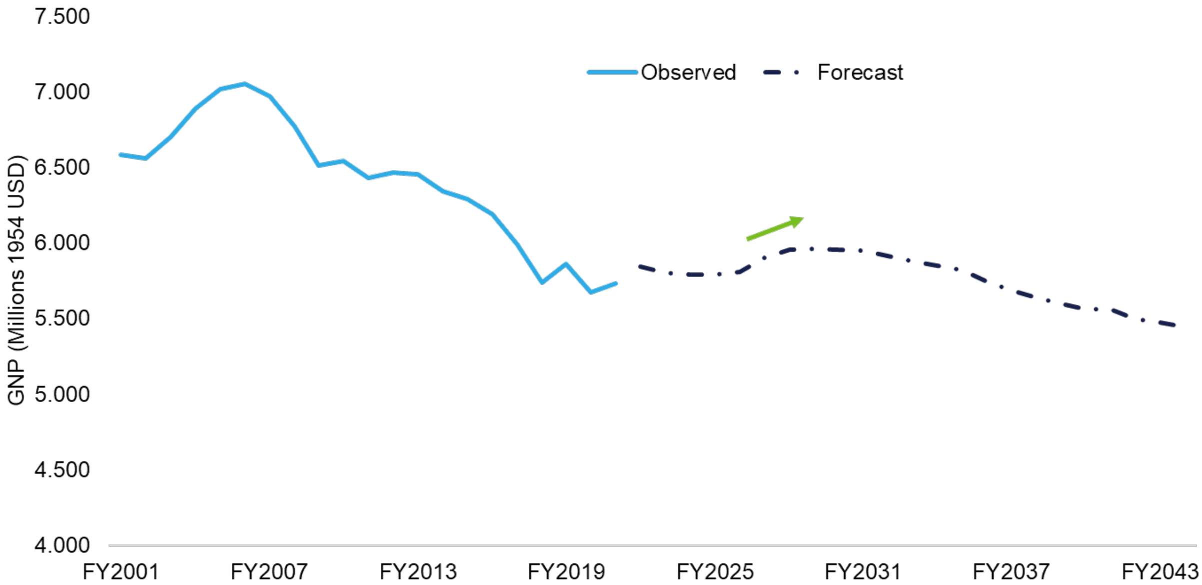
Figure 8: Historic and Forecast Gross National Product



Population Forecast

The population is anticipated to continue decreasing. The census revealed an increase in 2019 and 2020; however, the estimation after those years indicates a decline. The observed fiscal year 2001 to 2022 data exhibit a compound annual growth rate of -0.78%. The compound rate is anticipated to be similar negative trend from 2022 to 2044, at -0.86%.

Cooling Degree Days Forecast

GH used trend analysis to extrapolate observed CDD values and forecast temperature outcomes for the coming years. GH incorporated the increase in temperature over time by adjusting the monthly average CDD in the forecast period using a compound annual growth rate of 0.47%, which results in an annual increase of approximately 28 CDD.

Figure 9 displays the recorded annual values of CDD (black crosses). A red cross with a bar represents the median value of CDD over the observed period. The blue crosses represent the "normal" CDD for the forecast period, which is raised based on the trend and corresponds to the 50th percentile.

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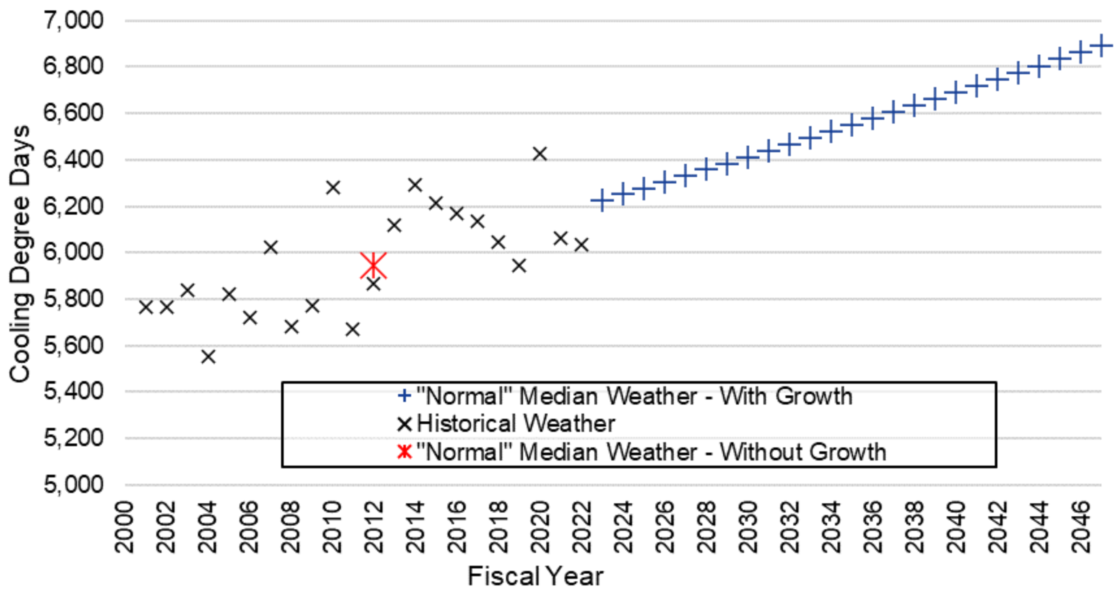
Figure 9: Observed and Forecast Cooling Degree Days[55]



3.1.9 Secondary Class Forecast

GH and LUMA comprehensively evaluated LUMA's internal forecast methodology for secondary customer classes. The forecasting approach for these classes relies on a static linear extrapolation of observed sales, assuming sales stability over time. This method was validated with a back-cast error of 0.2% of total electricity sales in the studied period.

Sales forecasts for the smaller classes remain consistent throughout the whole forecast period.

3.1.10 Total Sales at Meter Level Forecast

The sales forecast for the primary and secondary classes is combined to determine the total sales at the meter level. The forecast between 2024 and 2044 indicated a compound annual growth rate of 0.54%, which is lower than the yearly decrease from 2009 to 2023, which was 1.48%. Figure 10 and Table 31 show the sales forecast by class.

[55] Source: NOAA, analysis by Guidehouse

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Figure 10: Forecast Energy Sales by Customer Class at Customer Meter Level

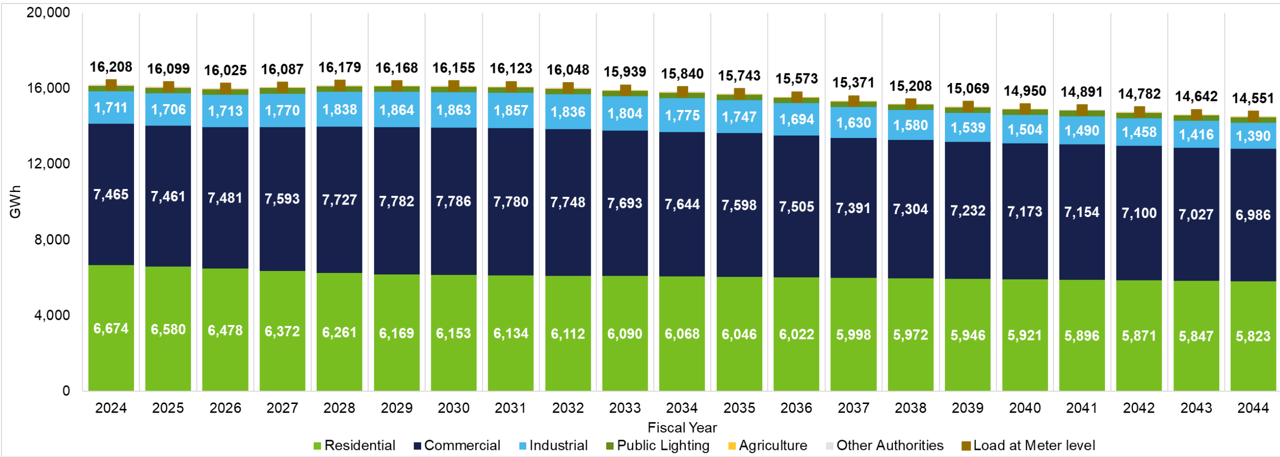


Table 30: Forecast Energy Sales

Fiscal Year	Residential (GWh)	Commercial (GWh)	Industrial (GWh)	Public Lighting (GWh)	Agriculture (GWh)	Others (GWh)	Total (GWh)
2024	6,674	7,465	1,711	296	24	39	16,208
2025	6,580	7,461	1,706	290	24	38	16,099
2026	6,478	7,481	1,713	291	24	38	16,025
2027	6,372	7,593	1,770	290	24	38	16,087
2028	6,261	7,727	1,838	290	24	38	16,179
2029	6,169	7,782	1,864	290	24	38	16,168
2030	6,153	7,786	1,863	291	24	38	16,155
2031	6,134	7,780	1,857	290	24	38	16,123
2032	6,113	7,748	1,836	290	24	38	16,048
2033	6,090	7,693	1,804	290	24	38	15,939
2034	6,068	7,644	1,775	291	24	38	15,840
2035	6,046	7,598	1,747	290	24	38	15,743
2036	6,022	7,505	1,694	290	24	38	15,573
2037	5,998	7,391	1,630	290	24	38	15,371
2038	5,972	7,304	1,580	291	24	38	15,209
2039	5,946	7,232	1,539	290	24	38	15,069
2040	5,921	7,173	1,504	290	24	38	14,950
2041	5,896	7,154	1,490	290	24	38	14,891
2042	5,871	7,100	1,458	291	24	38	14,782

Fiscal Year	Residential (GWh)	Commercial (GWh)	Industrial (GWh)	Public Lighting (GWh)	Agriculture (GWh)	Others (GWh)	Total (GWh)
2043	5,847	7,027	1,416	290	24	38	14,642
2044	5,823	6,986	1,390	290	24	38	14,551

3.1.11 Class Demand Profiles Construction

Approach to Customer Class Demand Profiles Construction

LUMA also developed an hourly demand forecast, which involves developing hourly demand profiles for each of the six customer classes. Based on data from FY2009 to FY2014, the current profiles were no longer up to date. To update them, a regression method was utilized to forecast historic class profiles for all years, aligning them with the hourly system generating profile. The calibrated profiles, covering FY2009 to FY2022, were tested to identify the most accurate historical profile year for distributing forecasted monthly sales hourly.

A demand profile for each customer class was generated by analyzing metering studies done by PREPA between FY2009 and FY2014. The demand profile covers one year and is divided into hour intervals, totaling 8,760 intervals. To forecast, it was necessary to gather rate-class profiles for a consistent set of past years and aggregate them into customer-class level profiles. Updating the profiles was crucial to reflect the changes in system-level demand patterns from FY2009 to FY2022.

Historic hourly system generation data was used to estimate the relationship between hourly rate class demand and system generation. The regression model took the following form:

$$y_t = \sum_{m=1}^{M=12} \sum_{k=1}^{K=4} \sum_{h=1}^{H=24} \beta_{mkh} \cdot SysGen_t \cdot Month_m \cdot DayType_k \cdot Hour_h + \varepsilon_t$$

Where:

y_t is the natural log of the rate class demand profile value in an hour t normalized to the historic monthly consumption in which hour t falls.

$SysGen_t$ is the natural log of the system generation profile value in an hour t.

$Month$ is a set of binaries, one for each calendar month.

$DayType$ is a set of binaries, one for each of four categories: (1) non-holiday weekdays, (2) holidays and weekends, (3) peak weekdays, and (4) peak holidays and weekends.56

56 A day was considered a peak day if it was among the top four system peaks occurring on a weekday or the top two system peaks occurring on a weekend in terms of aggregate system peak separately within each month.

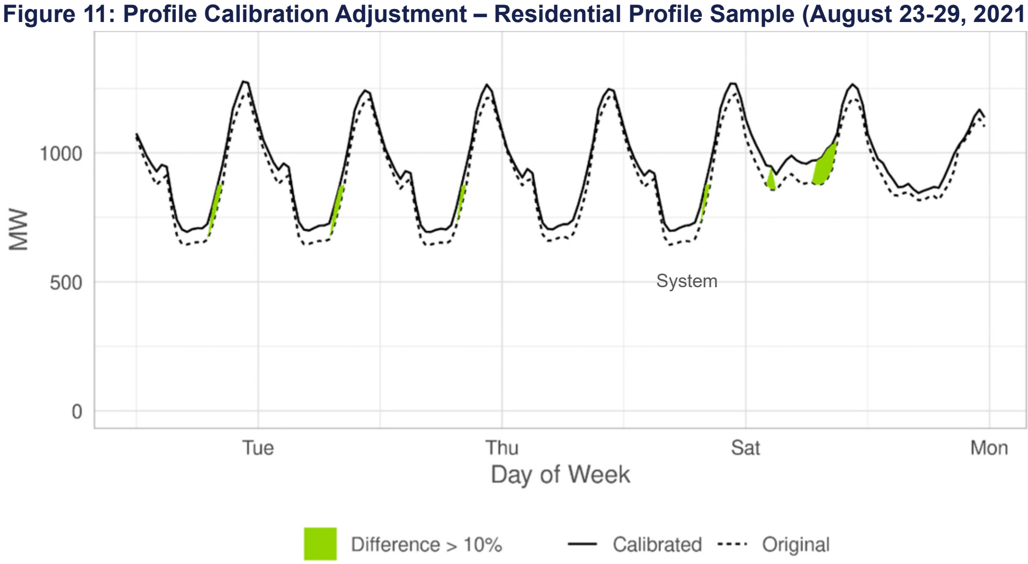
$Hour$ is a set of binaries, one for each hour of the day.

β_{mkh} is the set of regression coefficients uniquely defined for each hour h of day type k in month m.

Using the estimated regression parameters, hourly demand for each rate class throughout the Historical study period (FY2009 - FY2022) was predicted. The rate-class profiles were aggregated to produce customer-class profiles.

The profiles were calibrated to the historical remediated monthly class-level sales and hourly system generation. Figure 11 depicts a sample of the residential class profile before and after calibration to the system generation profile.

Figure 11: Profile Calibration Adjustment – Residential Profile Sample (August 23-29, 2021)



Profile Selection

After developing detailed customer profiles for each hour during the historic analysis period, GH selected a year to reflect the future demand profiles for every customer class. The main criterion considered for selection was the ability to predict peak demand accurately. Profiles from each fiscal year from FY2019 to FY2022 were evaluated using historic sales data from 2010 to 2022. Although the peak demand magnitudes were consistent across all possible years, their timing differed—the profiles for FY2019 consistently forecasted evening peaks, which were in line with historic data. However, the profiles for FY2020 to FY2022 occasionally predicted afternoon peaks, as there were changes in consumption patterns attributed to the impact of COVID-19. To account for this lack of consistency, FY2019 profiles were chosen for forecasting to more accurately predict future consumption patterns as the impacts of COVID-19 decrease.

Customer Class Profiles

Figure 12 illustrates the average customer class load shapes by season (summer) and day type (weekday). The load shapes are consistent throughout the winter and summer seasons.

The industrial profile (the light blue line) is relatively flat throughout the 24 hours, though industrial demand is slightly higher between 8 a.m. and 6 p.m. on weekdays than at other times. Commercial demand (dark blue line) is relatively low at night and high between 9 a.m. and 3 p.m. Residential demand (light green) is low during the day and peaks between 9 p.m. and 10 p.m. The residential air conditioning load may drive the residential demand profile peak.

The average daily peak in the aggregate system profile occurs between 7 p.m. and 9 p.m., primarily driven by residential class demand. Every annual peak demand (i.e., peak generation output) since FY2002 has happened between 8 p.m. and 10 p.m. See Figure 12 for a graph of the weekday and summer hourly demand profiles by customer class, and the system.

Figure 12: Fiscal Year 2019 Customer Class and System Demand Profiles (Weekday, Summer)

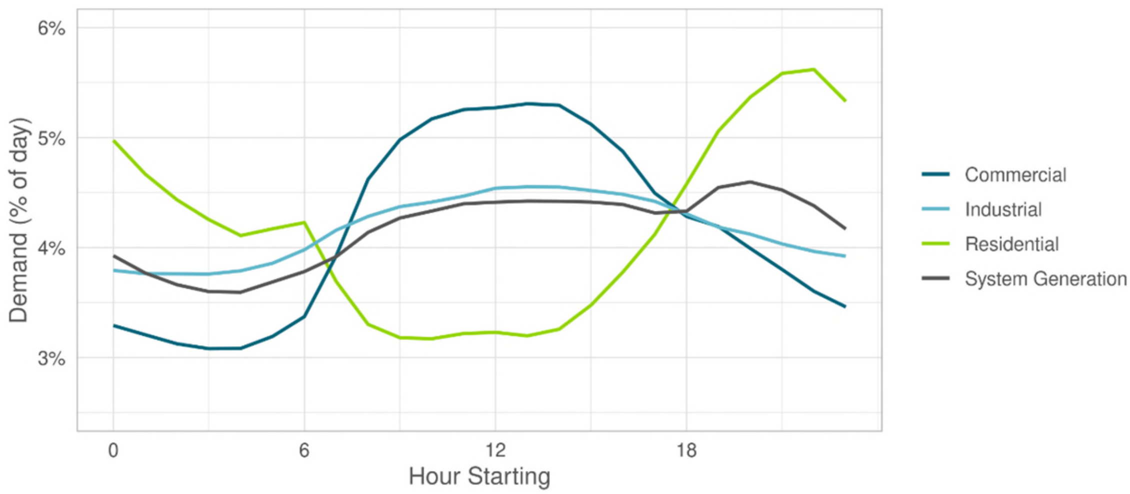


Figure 13 depicts average system-level demand profiles in FY2009 and FY2019. Over time, consumption during midday hours (8 a.m. - 3 p.m.) has declined, and consumption in the late afternoon and evening (4 p.m. - 10 p.m.) has increased slightly. These changes may result from increased adoption of air conditioning and the decline in Commercial sales, which contribute a greater share of mid-day demand.57

57 In FY2009, commercial sales were approximately 30% higher than residential sales, but in FY2022, they were only about 6% higher.

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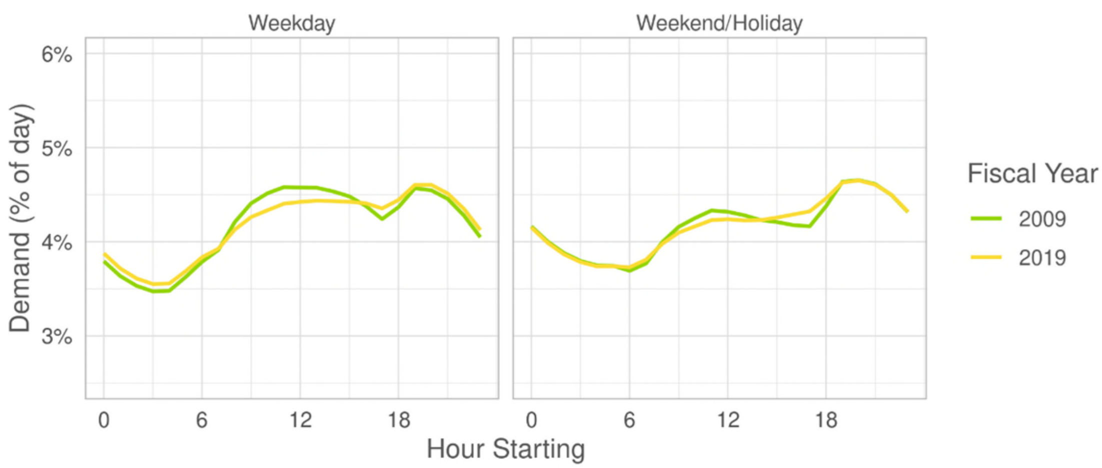
Figure 13: Change in Historical System Demand Profile, FY2009 versus FY2019



3.1.12 Loss Rates

The final step in developing the demand profile involved estimating loss rates to factor in the portion of the gross generation not billed due to transmission and distribution losses, generation plant auxiliary loads, consumption at LUMA/PREPA facilities, power theft, and consumption from other unknown users. Loss rates were applied to translate monthly sales into hourly generation requirements.

Losses were categorized into the following terms:

- Non-technical loss:
  - Loss attributed to power theft
  - Loss attributed to unbilled consumption
- Net technical loss:
  - Transmission loss
  - Substation loss
  - Primary distribution loss
  - Secondary distribution loss
- Gross technical loss:
  - All items included in the net technical loss
  - Auxiliary load consumption at power plants
  - Consumption at LUMA/PREPA facilities (own use)

- Consumption from other unbilled and known legitimate users

- Total loss:
  - Non-technical loss
  - Gross technical loss

The historical total loss rates decreased from approximately 18% in FY2009 to 15% in FY2022. Data on non-technical and net technical losses by transmission and distribution voltage levels were utilized to produce a bottom-up estimate of the customer class loss rates. A calibration adjustment was applied to convert the net technical loss estimates to gross technical losses, ensuring consistency with top-down estimates derived from historical aggregate sales and generation data. The resulting data in Table 31 contains estimates of non-technical loss rates, net and gross technical loss rates, and total loss rates by customer class.

Table 31: Customer Class Loss Rates

Customer Class	Nontechnical Loss (A)	Net Technical Loss (B)	Gross Technical Loss (C)	Total Loss (A + C)
Residential	3.7%	10.3%	15.2%	18.9%
Commercial	2.5%	7.7%	11.6%	14.1%
Industrial	1.0%	3.3%	5.2%	6.2%
Agriculture	3.7%	10.3%	15.2%	18.9%
Public Lighting	3.7%	10.3%	15.2%	18.9%
Other Authorities	0.9%	3.0%	4.7%	5.6%

3.1.13 Total Energy Forecast at Generator

The energy forecast at the generator meter level was calculated by factoring in the losses based on customer class. Table 32Table 32 below shows the energy forecast at the generator meter level and Figure 14 compares the energy production to energy consumption at the meter level.

Table 32: Energy Forecast at Generator Meter Level

Fiscal Year	Residential (GWh)	Commercial (GWh)	Industrial (GWh)	Public Lighting (GWh)	Agriculture (GWh)	Others (GWh)	Total (GWh)
2024	8,230	8,688	1,825	365	29	41	19,178
2025	8,114	8,684	1,819	358	29	40	19,045
2026	7,988	8,707	1,827	359	29	41	18,951
2027	7,858	8,838	1,887	358	29	40	19,010
2028	7,721	8,994	1,960	358	29	40	19,102
2029	7,607	9,058	1,988	358	29	40	19,080
2030	7,588	9,062	1,986	359	29	41	19,065

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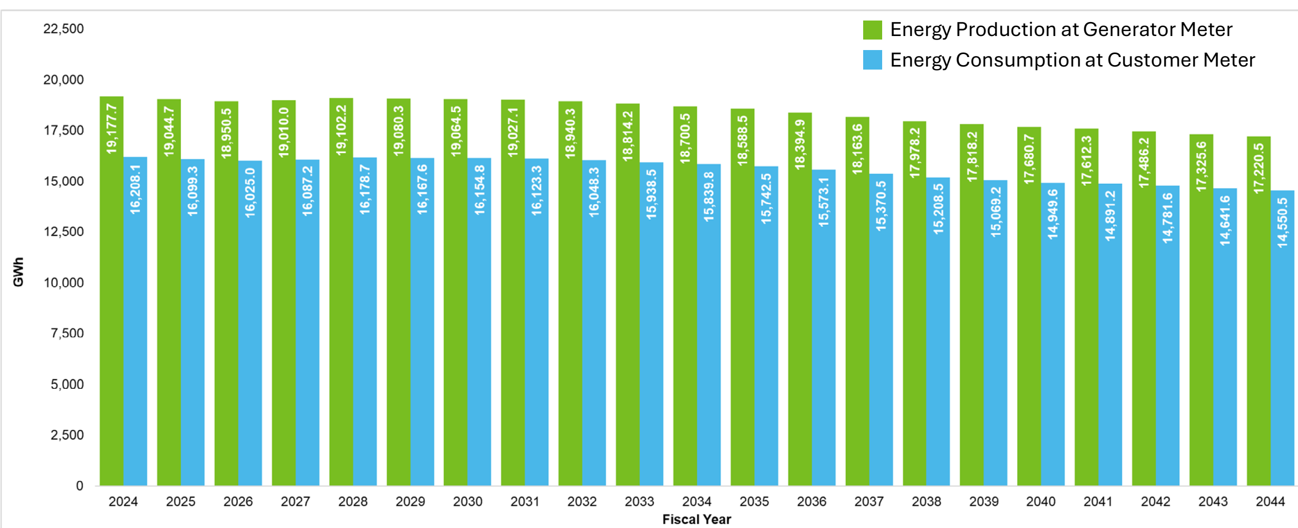
Fiscal Year	Residential (GWh)	Commercial (GWh)	Industrial (GWh)	Public Lighting (GWh)	Agriculture (GWh)	Others (GWh)	Total (GWh)
2031	7,564	9,056	1,980	358	29	40	19,027
2032	7,538	9,018	1,958	358	29	40	18,940
2033	7,510	8,954	1,923	358	29	40	18,814
2034	7,482	8,898	1,892	359	29	41	18,701
2035	7,455	8,844	1,863	358	29	40	18,589
2036	7,426	8,735	1,806	358	29	40	18,395
2037	7,396	8,603	1,738	358	29	40	18,164
2038	7,364	8,501	1,685	359	29	41	17,978
2039	7,332	8,418	1,641	358	29	40	17,818
2040	7,301	8,349	1,604	358	29	40	17,681
2041	7,270	8,326	1,589	358	29	40	17,612
2042	7,240	8,264	1,555	359	29	41	17,486
2043	7,210	8,179	1,510	358	29	40	17,326
2044	7,180	8,131	1,482	358	29	40	17,221

Figure 14: Energy Forecast at Generator Meter Level



3.1.14 Approach to Develop Alternative Core Forecast Scenarios

In collaboration with LUMA, GH developed a range of high and low-demand scenarios to account for uncertainty in macroeconomic conditions, temperature, and system peak demand. Four sources of variation were incorporated:

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- Variation in macroeconomic conditions
- Variation in average monthly temperature conditions
- Other peak variation
- Modified low and high-demand scenarios

Low Scenario

- Variation in Macroeconomic Conditions:
  - Alternative macroeconomic forecast scenarios from Moody's Analytics were applied to the FOMB forecast macroeconomic variables to construct a set of alternative input macroeconomic conditions.
  - The range between the low and high macroeconomic forecasts from Moody's Analytics was narrow.
  - An additional adjustment was applied to the low-demand scenarios for the three primary customer classes to better reflect a plausible lower bound.
- Variation in Average Monthly Temperature Conditions:
  - The distribution of historical temperature was used to construct a scenario reflecting lower CDDs, resulting in a lower demand.
- Other Peak Variation:
  - An additional adjustment of -170 MW to system peak demand was applied to the low-temperature scenarios to account for short-term local weather conditions and other factors that might influence peak demand.
- Modified Low-Demand Scenarios:
  - Historical declining trend in per-customer energy use: An adjustment was applied to reflect a scenario with use per customer returning to pre-pandemic trends. Use-per-customer declined for all major classes (residential, commercial, industrial) during the pre-pandemic period (2011-2019).

Table 33 below shows the energy sales forecast at the generator level for the Low Scenario.

Table 33: Sales Forecast at Generator Level (Low Scenario)

Fiscal Year	Residential (GWh)	Commercial (GWh)	Industrial (GWh)	Public Lighting (GWh)	Agriculture (GWh)	Others (GWh)	Total (GWh)
2024	7,882	7,971	1,588	364	29	41	17,875
2025	7,723	7,770	1,528	358	29	40	17,448

Fiscal Year	Residential (GWh)	Commercial (GWh)	Industrial (GWh)	Public Lighting (GWh)	Agriculture (GWh)	Others (GWh)	Total (GWh)
2026	7,550	7,761	1,562	359	29	40	17,302
2027	7,364	7,836	1,637	358	29	40	17,265
2028	7,171	7,890	1,702	358	29	40	17,190
2029	6,982	7,845	1,719	358	29	40	16,974
2030	6,858	7,756	1,714	359	29	40	16,756
2031	6,727	7,645	1,698	358	29	40	16,497
2032	6,589	7,499	1,665	358	29	40	16,180
2033	6,448	7,313	1,611	358	29	40	15,800
2034	6,308	7,127	1,557	358	29	41	15,420
2035	6,168	6,957	1,511	357	29	40	15,063
2036	6,026	6,735	1,438	358	29	40	14,626
2037	5,881	6,493	1,354	357	29	40	14,155
2038	5,734	6,282	1,286	358	29	41	13,730
2039	5,586	6,089	1,226	357	29	40	13,328
2040	5,438	5,905	1,171	357	29	40	12,941
2041	5,289	5,768	1,139	357	29	40	12,624
2042	5,140	5,592	1,089	358	29	41	12,248
2043	4,990	5,392	1,026	357	29	40	11,835
2044	4,840	5,229	981	357	29	40	11,477

High Scenario

The high scenario load forecast for the 2025 IRP was first developed using historical data through FY2023. GH later revised the high version of the load forecast and summarized the work in its January Report Addendum, included in Appendix 7. GH revised the high scenario forecast by updating five inputs to reflect:

- GNP Update. GH updated the high scenario projected GNP series to reflect the FOMB and Moody's updated economic projections. The GNP series is applied to the estimated regression parameters to drive the high commercial and industrial sales scenario forecast.
- Population Update. GH updated the high-scenario projected population series applied to the estimated regression parameters to drive the high-scenario forecast of residential sales.
- CDD Update. GH updated the high scenario IRP analysis to include observed historical CDD through September 2024. CDD drives the residential and commercial sales forecast.
- Peak Volatility Factor Update. GH updated the peak demand volatility factor to reflect the increased range of variation in de-trended system peak demand driven by the extreme weather observed in the

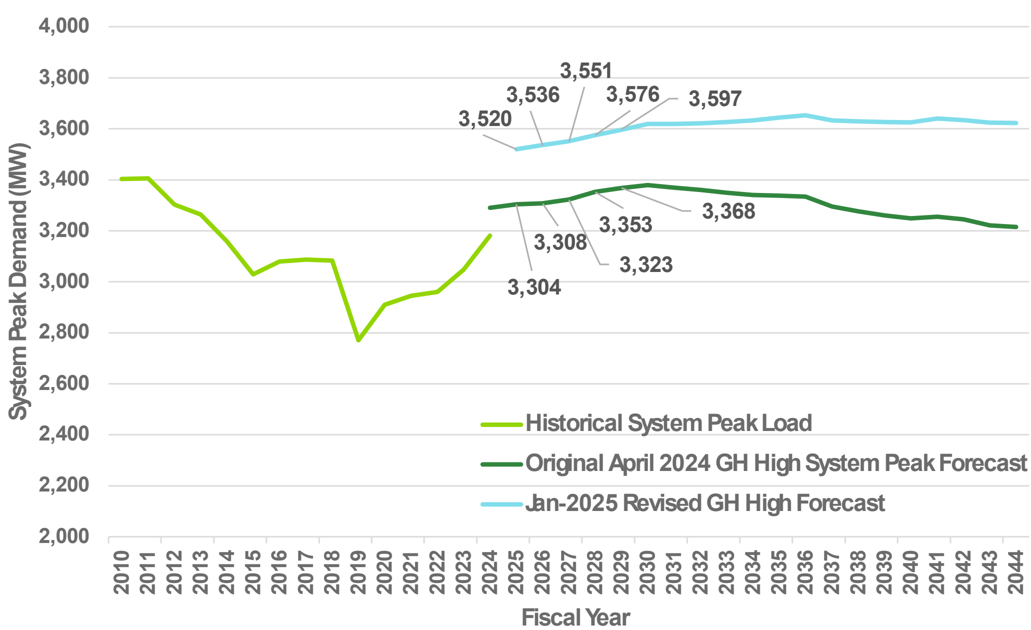
summer of 2024. The volatility factor is applied to the hourly disaggregation of peak monthly sales to reflect the historically observed variation in annual peak demand values due to factors beyond macroeconomic trends and monthly CDD.

- Industrial Model Update. GH updated the monthly industrial regression model parameters used to forecast industrial sales to align with the regression model parameters used to forecast the FY2024 Fiscal Plan. This update was necessary due to the inclusion of the updated (higher) GNP projection. Without an update of the model parameters, the industrial model would over-forecast sales in the high scenario when applied to the updated GNP.

In consultation with GH, the LUMA 2025 IRP team determined that the abovementioned changes would most significantly impact the high scenario demand. LUMA chose to update the high scenario only, and the base scenario and low scenario have not been updated and remain as published in the original forecast in the April 2024 GH Load Forecast Report.

Figure 15 provides a graphical presentation of the historical system peak loads, the original high forecast from the April 2024 GH Load Forecast Report, and the revised high forecast from the GH Addendum to the April 2024 Report.

Figure 15: System Peak Load Forecast



In addition to that, Figure 16 showcases the annual generation history and compares the original low and base forecasts from the April 2024 GH Load Forecast Report with the revised high forecast from the GH Addendum to the April 2024 Report.

Figure 16: Annual Generation History and Forecast Scenarios

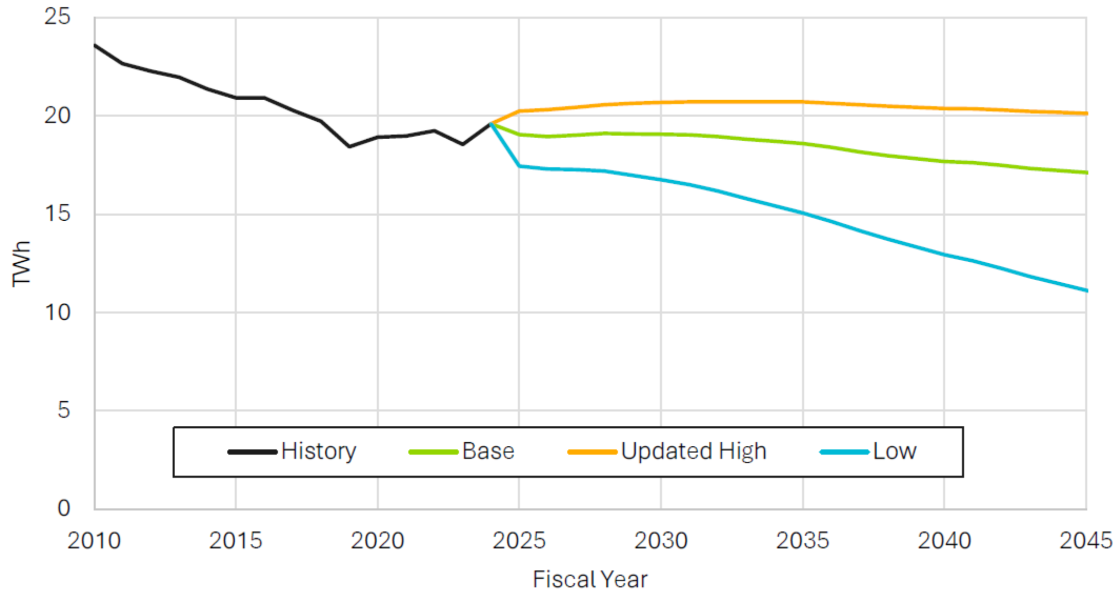


Table 34: Sales Forecast at Generator Level (High Scenario)

Fiscal Year	Residential (GWh)	Commercial (GWh)	Industrial (GWh)	Public Lighting (GWh)	Agriculture (GWh)	Others (GWh)	Total (GWh)
2025	8,567	9,268	1,970	358	29	40	20,232
2026	8,588	9,314	1,988	358	29	40	20,319
2027	8,610	9,377	2,015	358	29	40	20,428
2028	8,630	9,454	2,048	358	29	40	20,559
2029	8,647	9,495	2,063	358	29	40	20,633
2030	8,663	9,519	2,071	358	29	40	20,682
2031	8,675	9,529	2,072	358	29	40	20,703
2032	8,683	9,531	2,069	358	29	40	20,710
2033	8,689	9,529	2,064	358	29	40	20,708
2034	8,690	9,533	2,061	359	29	40	20,712
2035	8,688	9,533	2,057	358	29	40	20,705
2036	8,683	9,497	2,035	358	29	40	20,643
2037	8,676	9,446	2,006	358	29	40	20,556
2038	8,669	9,406	1,983	358	29	40	20,486
2039	8,660	9,374	1,963	358	29	40	20,425
2040	8,652	9,348	1,946	358	29	40	20,373

Fiscal Year	Residential (GWh)	Commercial (GWh)	Industrial (GWh)	Public Lighting (GWh)	Agriculture (GWh)	Others (GWh)	Total (GWh)
2041	8,644	9,344	1,940	358	29	40	20,355
2042	8,636	9,316	1,921	358	29	40	20,302
2043	8,629	9,275	1,897	358	29	40	20,228
2044	8,621	9,248	1,880	358	29	40	20,176

Macroeconomic Scenarios

High and low macroeconomic scenarios were created using economic forecasts from Moody's Analytics, defining Scenario 0 (S0) as the high-growth scenario, Base as the core scenario, and Scenario 4 (S4) as the low-growth scenario. The FOMB GNP forecast was used as the base economic scenario, and the Moody's high/low scenarios were calibrated to be centered around the FOMB scenario. The calibration adjustment preserves the relationship between LUMA loads and FOMB macroeconomic forecasts while utilizing the relative variation in the original Moody's scenario forecasts.

The population forecast varies across the scenarios, with a relationship counter to the scenario definitions (upside/downside). For example, the S0 scenario has the highest GNP, but the lowest projected population in all the years of the forecast. Moody's Analytics explained that Puerto Rico's economic scenarios depend on the U.S. economy. When the U.S. economy grows, more people from Puerto Rico move to the mainland U.S., reducing Puerto Rico's population. However, because Puerto Rico's economy is closely linked to the U.S. economy, Puerto Rico's GDP still increases even as its population declines.

Temperature Scenarios

High—and low-temperature scenarios were developed by applying alternative CDD projections to predict monthly customer-class sales. The escalated monthly CDD projection from each historical year (2000-2022) was used for each forecast year. The scenarios producing the highest and lowest system-level peak demand were selected as the high/low-temperature scenarios.

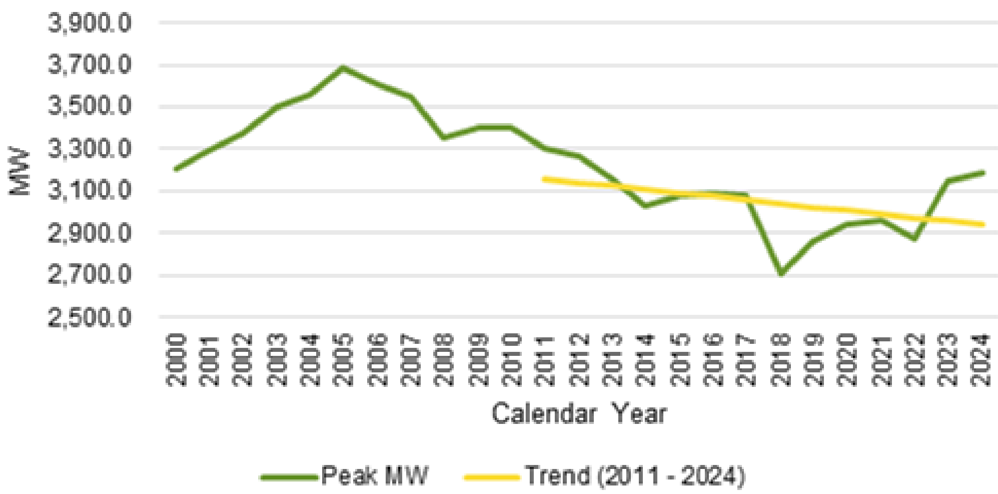
3.1.15 Peak Volatility Factor

Adjustments were made to high and low-demand scenarios based on historical peak demand variation analysis to capture the impact of short-term weather events on peak demand. The study reflected peak variations that could not be attributed to the econometric drivers or CDD values. These variations indicated that, in any given year, system peak demands could vary from -170 MW for the Low Scenario to +295 MW for the High Scenario. These results adjusted the respective high and low system peak demand forecasts. The High Scenario adjustment was referred to as "Other Peak Variation" in the April 2024 GH Load Forecast Report and as the "Peak Volatility Factor" in the GH Addendum to the April 2024 Report. Adjustments were distributed among customer classes based on their original demand proportions. Further explanation of the methodology employed to determine these adjustments can be found in the April 2024 GH Load Forecast Report, Section 6.3, and the GH Addendum to the April 2024 Report, Section 2.4.

Step 1. Estimate Trend of Peak Volatility Factor: To estimate the trend of the Peak Volatility Factor, GH fitted a linear trend to historical system peak loads.

Figure 17 depicts historical observed peak generation (green line) with a linear trend (yellow line) during the historical IRP study period (2011-2024[58]).

Figure 17: Observed Historical System Peak Load with Linear Trend



Step 2. Estimate Trend Residuals: The GH team estimates the trend residuals, taking the difference between annual historical peaks and the linear trend from the analysis above. These residuals represent the deviation of historical peaks from the trend-normalized expected peak. Figure 18 depicts the annual residuals.

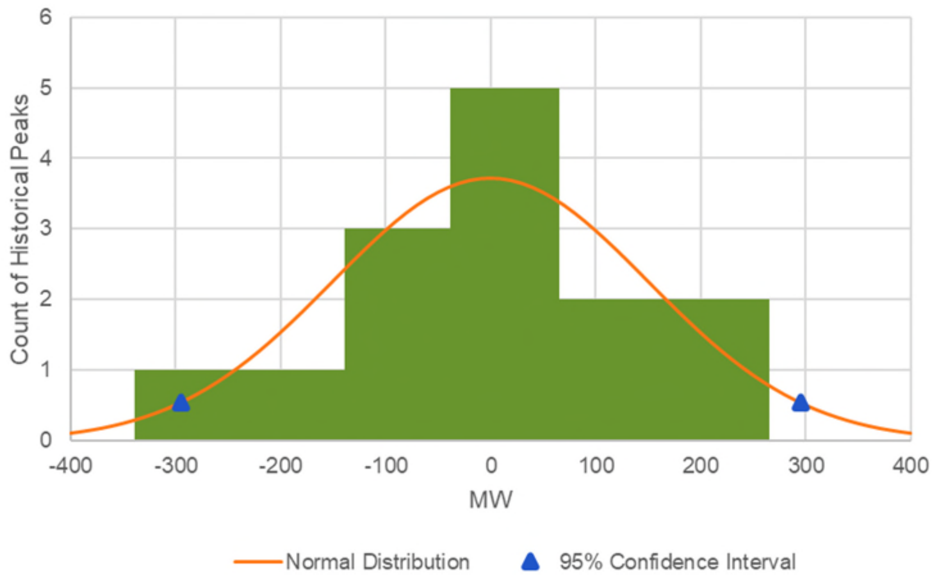
Figure 18: Trend-Normalized Historical Peaks (Residuals)

Step 3. Estimate Distribution of Peaks and 95th Percentile Peak: The GH team used the trend-normalized peaks to estimate a 95% confidence interval, assuming the trend-normalized peaks follow a normal distribution. The upper confidence interval value provides a peak volatility factor that can be added to the peak in the high-demand scenario. Figure 19 depicts a histogram distribution of the historical peak residuals with a normal distribution overlay calculated using the mean and standard deviation of the

[58] The April 2024 GH Load Forecast Report used historical data from July 2010 to June 2022 (fiscal year 2011 to 2022), and the revised high forecast from the GH Addendum to the April 2024 Report used historical data from calendar year 2011-2024.

residuals. The blue triangle on the right side of the figure provides the upper limit of the 95% confidence interval value, which lies at 295 MW.

Figure 19: Trend-Normalized Historical Peaks (Residuals)



3.2 Load Modifier Forecasts

3.2.1 Distributed Solar Photovoltaic Forecast

LUMA originally planned to adopt the DPV forecast from the 2LMNet scenario of the PR100 Study.[59] However, the growth in DPV installations in 2023 and 2024 showed actual historic installations that far exceeded the values the PR100 Study had forecasted. Based on the 2023 and 2024 historical data, LUMA chose to use as its base DPV forecast its most recent DPV forecast at the time, the LUMA 02.2024 DPV forecast, which had been used as the input to the FOMB forecast and budget filings. A comparison of the LUMA 02.2024 forecast and the PR100 2LMNET forecasts of DPV is shown in Figure 20 and Table 35 for the period addressed in the 2025 IRP (2025 to 2044).

[59] Puerto Rico Grid Resilience and Transitions to 100% Renewable Energy Study, Final Report (PR100 Study), March 2024, https://www.nrel.gov/docs/fy24osti/88384.pdf.

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Figure 20: Graphic Comparison of LUMA and PR100 Distributed Photovoltaic Capacity Forecasts

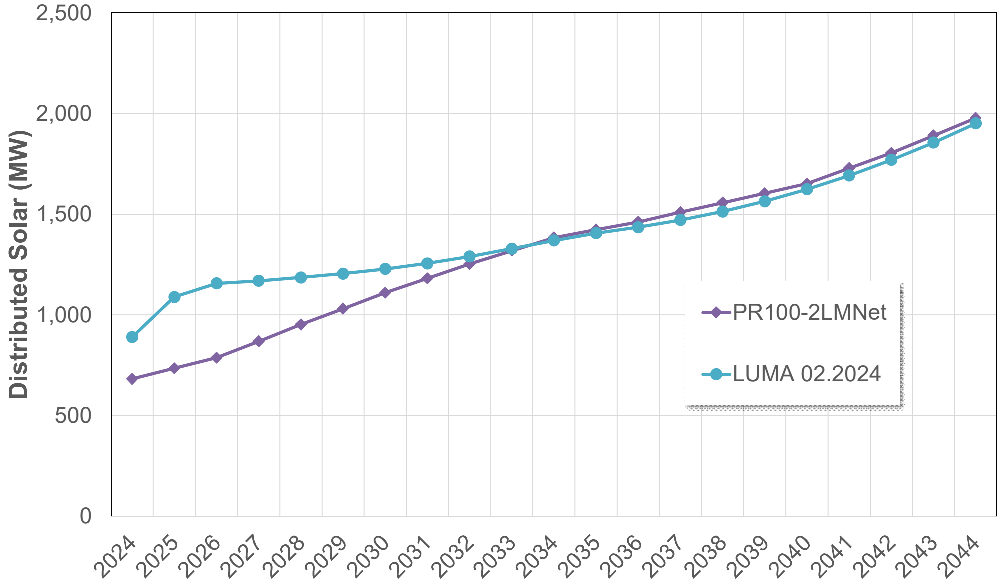

Table 35: Comparison of LUMA Base Case DPV and PR100 DPV Forecasts

Year	PR100-2LMNet DPV Forecast (MW)	Base Case DPV Forecast 02.2024 (MW)	Delta PR100 vs LUMA
2024	682	890	-30.5%
2025	735	1,089	-48.2%
2026	787	1,156	-46.9%
2027	869	1,170	-34.6%
2028	952	1,186	-24.5%
2029	1,031	1,205	-16.9%
2030	1,110	1,228	-10.7%
2031	1,181	1,256	-6.4%
2032	1,253	1,290	-3.0%
2033	1,319	1,329	-0.7%
2034	1,384	1,370	1.0%
2035	1,423	1,405	1.2%
2036	1,462	1,436	1.8%
2037	1,510	1,471	2.6%
2038	1,557	1,513	2.8%
2039	1,604	1,564	2.5%

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Year	PR100-2LMNet DPV Forecast (MW)	Base Case DPV Forecast 02.2024 (MW)	Delta PR100 vs LUMA
2040	1,651	1,624	1.6%
2041	1,728	1,692	2.1%
2042	1,804	1,770	1.9%
2043	1,891	1,856	1.8%
2044	1,978	1,951	1.4%

As illustrated in Figure and Table 35, the PR100 forecast is significantly lower than the LUMA forecast for the first 8 years (2024 to 2031), ranging from 48.2% to 16.9% and averaging 27.3% lower in the first eight years. However, in the final thirteen years (2032 to 2044), the forecast converges with a maximum differential between the two estimates of only 3% and an average difference of 1.3%.

For the 2025 IRP, LUMA defined the high DPV forecast as 25% higher than the base DPV forecast by 2044, measured in megawatts (MW) and a low DPV forecast reflecting a 15% decrease from the base case by 2044, also measured in MW. However, only the base case DPV forecast was utilized in the Scenarios ordered by the Energy Bureau for use in the 2025 IRP.

Figure 21 presents the forecast of the Base Case DPV capacity impact as measured at the utility generator.

Figure 21: DPV Capacity Forecast at Utility Generator – Base Case

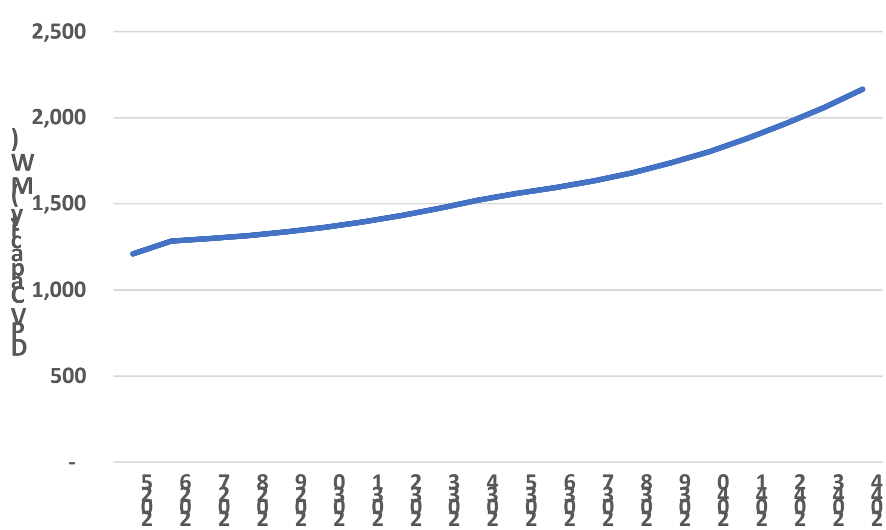
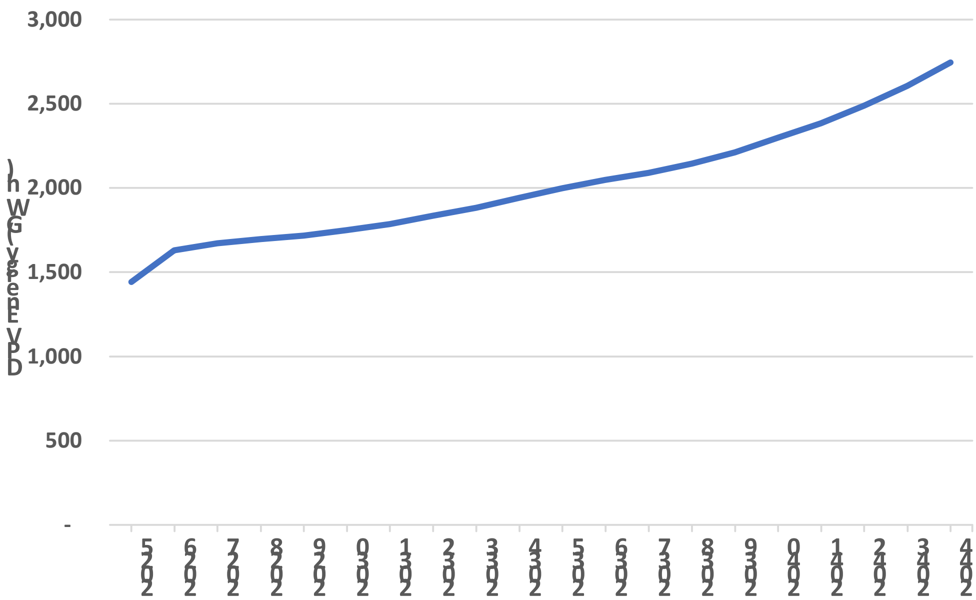


Figure 22 presents the forecast of the Base Case DPV energy impact as measured at the utility generator.

Figure 22: DPV Energy Forecast Impact at Utility Generation - Base Case



3.2.2 Controlled Distributed Battery Energy Storage System Forecast

Base Case Distributed Battery Energy Storage System Forecast

LUMA did not generate an independent DBESS forecast but instead adopted the DBESS forecast from the PR100 Study's 2LMNet scenario as the DBESS forecast for the 2025 IRP. The PR100 forecast for DPV and DBESS were interrelated and used benefit-cost analysis inputs in their development. LUMA selected the DBESS' PR100 2LMNET forecast, adjusted for system losses, as the base case forecast for the 2025 IRP because it aligns with the corresponding DPV's PR100 2LMNET forecast and the DPV forecast developed by LUMA for the FOMB filings and then in turn adopted as the DPV forecast base case for the 2025 IRP. Section 3.1 shows that this DPV forecast closely tracks LUMA's DPV forecast from 2032 to 2044.

As with the 2025 IRP DPV forecast high and low variations, LUMA defined the high DBESS forecast as 25% higher than the base DBESS forecast by 2044, as measured in MW, and at the low DBESS forecast as a 15% decrease from the base case DBESS forecast by 2044, as measured in MW. However, only the base case DBESS forecast was utilized in the Scenarios ordered by the Energy Bureau for use in the 2025 IRP.

Table 36 provides the forecast for installed DBESS capacity for the base case.

Table 36: LUMA DBESS Capacity as Measured at the Generator

Year	Base Case DBESS Forecast (MW)
2024	337

Year	Base Case DBESS Forecast (MW)
2025	345
2026	355
2027	366
2028	382
2029	401
2030	422
2031	445
2032	472
2033	502
2034	531
2035	560
2036	594
2037	634
2038	678
2039	727
2040	773
2041	815
2042	864
2043	919
2044	968

Each of the customer-owned DBESS batteries were assumed to have four hours of energy storage capacity.

Controlled DBESS Program

LUMA has in operation a Customer Battery Energy Sharing (CBES) that utilizes a portion of a customer's DBESS capacity as an energy resource available for LUMA dispatch, to avoid or reduce interruptions to service during periods when there is insufficient utility generation to fully meet customer load requirements. This voluntary customer program is primarily intended to draw upon the portion of customer batteries enrolled only during emergency events to avoid or reduce loss of load.

In the future, LUMA intends to develop additional customer DBESS programs that will be able to draw upon customer batteries during non-emergency, normal operations to reduce the costs of providing reliable electric service to customers. The IRP is principally intended to recommend an energy resource plan that provides the electrical customer of Puerto Rico reliable and cost-effective service that is designed to minimize the chance of emergency events and the potential for loss of load. Since CBES are

DBESS that are solely considered for emergency use, LUMA believes the CBES program and its enrolled customer DBESS resources should remain separate and distinct from the resources assessed in the IRP. Therefore, LUMA has chosen to exclude the DBESS capacity enrolled in the CBES program in energy resources considered in the 2025 IRP. However, LUMA believes future DBESS programs can provide a cost-effective addition to the resources available to LUMA to meet the normal, non-emergency, operations and be called upon to support the system when economic to do so. In anticipation of being able to develop future DBESS programs that are cost effective as a utility resource and desirable to customer who enroll in these programs, LUMA has included in the 2025 IRP the “Controlled DBESS” program, described above, that represents customer batteries enrolled in a program that allows LUMA to economically dispatch the portion of the customer’s battery which they choose to enroll in the program. Ultimately this program could be implemented as a standalone program operated by LUMA or with as a program that utilizes third-party aggregators that dispatch the DBESS resources of their collective customers based on the LUMA system needs.

To assess Controlled DBESS, as well as other demand response (DR) programs, as potential resource options, LUMA engaged Guidehouse to complete a necessarily high-level analysis. The analysis was considered a preliminary, high-level analysis since no Puerto Rico-specific baseline or potential study existed for any of the programs analyzed. The Guidehouse analysis60 included assessment of the program costs and benefits, including incentives paid to customers for a number of DR programs. One of the programs defined and assessed was the “Behind-the-Meter (BTM) Battery Dispatch” program.61 Guidehouse’s BTM Dispatch program provided the cost basis for LUMA’s estimate for the Controlled DBESS program assessed in the 2025 IRP of $226/kW-yr. levelized cost.

The Guidehouse analysis estimated that customers would enroll an average of 31% of the energy capacity of their batteries in the program. LUMA experience has indicated that customers in Puerto Rico have enrolled approximately 30% of their battery capacity on average in the CBES program. Both LUMA’s limited experience with the CBES customer enrollment and other utility programs indicate that customers will typically only enroll a portion of their available battery capacity, leaving some of the capacity available for emergency backup or to time shift their energy use to take advantage of Time of Use differential electric pricing. In the 2025 IRP, the PREB has ordered LUMA to utilize an assumption that customers will enroll an average 30% of their battery capacity in future Controlled DBESS programs. In addition, the Energy Bureau ordered LUMA to assume a progressive increase in the enrollment of customers in a Controlled DBESS program.

For one supplemental Scenario the Energy Bureau ordered LUMA to assume customers will enroll 100% of their battery capacity in a Controlled DBESS program and will attain a more rapid enrollment and higher ultimate ceiling to the enrollment. LUMA believes that both the assumption that 100% of battery capacity will be enrolled and that there will be rapid progression of enrollment are extreme and unlikely to be realized. Table 37 provides the annual forecast of Controlled DBESS enrollment for both the Base Case, which assumed 30% of battery capacity is enrolled, and the Extreme Case, which assumes 100% of battery capacity is enrolled.

[60] Guidehouse DR Potential Study, completed for LUMA August 2024.
[61] Ibid, Section 3.5.3, page 41.

Table 37: Forecasted Controlled DBESS Enrollment

Year	Base Case Forecasted Penetration of DBESS Owners Enrolled in Controlled DBESS Program	Extreme Case Forecasted Penetration of DBESS Owners Enrolled in Controlled DBESS Program
2025	0%	0%
2026	0%	0%
2027	3%	6%
2028	7%	14%
2029	11%	22%
2030	15%	30%
2031	16%	34%
2032	17%	38%
2033	18%	42%
2034	19%	46%
2035	20%	50%
2036	21%	52%
2037	22%	54%
2038	23%	56%
2039	24%	58%
2040	25%	60%
2041	25%	60%
2042	25%	60%
2043	25%	60%
2044	25%	60%

3.2.3 Energy Efficiency Forecast

Energy Efficiency Forecast Overview

Many utilities and governments worldwide are pursuing EE programs. These programs are designed to reduce energy use without reducing the quality of services, such as comfort, productivity, or product quality provided to consumers. This section describes LUMA's forecast of potential electricity use reductions due to EE. In the IRP, EE is used to reduce the core load forecast.

The LUMA EE forecast presented here relies on the work carried out by the PR100 team and documented in the PR 100 Study. This is particularly appropriate, as one of the PR100 EE forecast variations included the impact of the full implementation of EE measures that LUMA defined in its preliminary EE program plan, described in the LUMA Transition Period Plan (TPP)[62]. However, PR100 also included savings from natural turnover and codes and standards.

The PR100 team developed two versions of the EE forecast for their analysis:

- The bottom-up approach builds on savings anticipated from codes, standards, natural turnover, and programs proposed in the TPP (described in Section 0.I). While the TPP only estimated the savings for the first two years of the EE programs' implementation, the PR100 bottom-up approach extended the EE savings growth for an additional 28 years, for a total of 30 years. The bottom-up PR100 EE forecast reflects the participation rates expected in the TPP. PR100 experts then extended these participation rates for the balance of the forecast period.
- The top-down approach was specifically designed to achieve the EE savings goal defined in Act No. 17-2019. The Act 17 EE goal requires Puerto Rico to achieve 4,744 GWh/year of electricity savings by 2040. The 4,744 GWh/year is based on 30% of PREPA's fiscal year 2019 sales. The top-down forecast development started with extending the bottom-up forecast to 100% participation. It should be noted that typical EE measures have participation rates less than 100% if they are designed so that the measure benefits equal or exceed the costs. When the total savings achieved with 100% participation did not reach the level of the Act 17 savings goal, the PR100 team further scaled up the savings sufficient to achieve compliance with the EE target of 30% savings by 2040.

Similar to PR100, LUMA includes a bottom-up and top-down EE forecast in its 2025 IRP Scenarios.

PR100 EE Forecast Process

The traditional approach to developing an EE forecast starts with a market baseline (inventory of current conditions of buildings, energy-using equipment, and processes in all customer sectors of interest). This is then followed by technical and market potential studies that establish technically and economically feasible EE measures and programs. When the PR100 EE forecasts were available, neither the market baseline analyses nor the technical and market potential studies were available for Puerto Rico. Without this foundational data, PR100 and LUMA adopted an approach that relies on estimates of incremental energy savings due to various EE measures. Most of the EE forecast methodology description in this section is drawn from the PR100 Study[63] without additional citations or quotations.

Bottom-Up Energy Efficiency Forecast

PR100 took the following general approach to estimating the bottom-up EE forecast. Each of these parameters is described below:

[62] Motion Submitting Proposed EE/DR Transition Period Plan to the Honorable Puerto Rico Energy Bureau, Puerto Rico Energy Bureau, Case No. NEPR-MI-2022-001. https://energia.pr.gov/wp-content/uploads/sites/7/2022/06/Motion-Submitting-Proposed-EE-DR-Transition-Period-Plan-NEPR-MI-2021-0006.pdf.

[63] PR100 Study, Sec. 5.2, Energy Efficiency. https://pr100.gov/

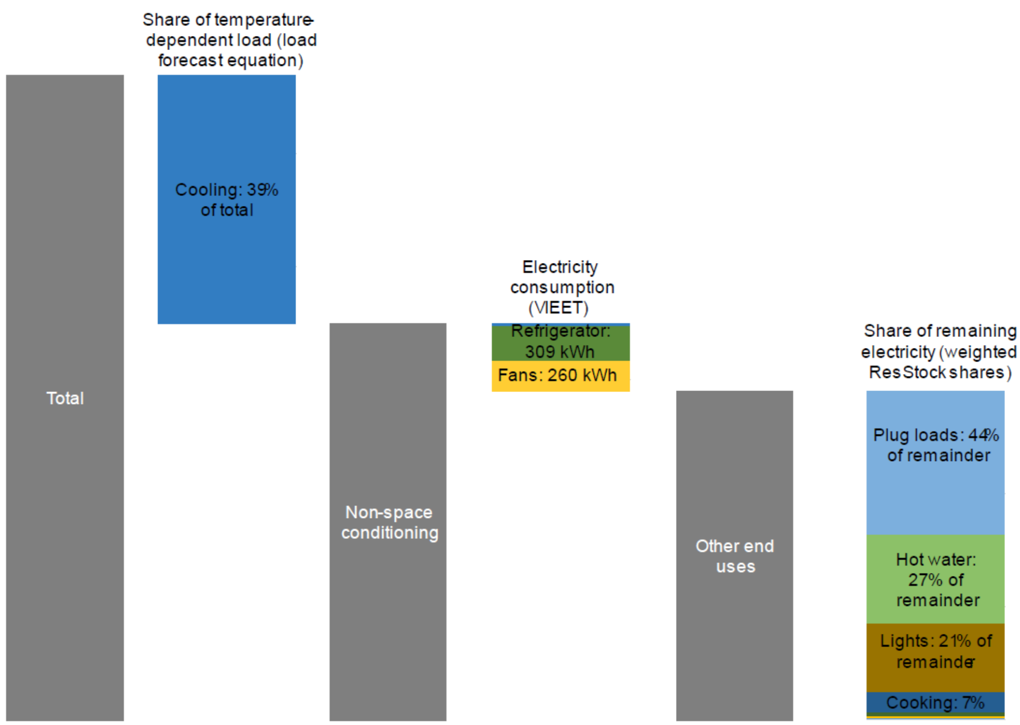
Figure 23: Annual End-Use Savings Formula[64]

Annual end use savings = Annual consumption of an end use x Percentage increase in efficiency x Share of stock that turned over

Annual End-Use Consumption

Total annual consumption is based on hourly electricity consumption by the customer sector for FY2017, which was used in PREPA's 2020 IRP. Customer sector data is then disaggregated into end-uses using the National Renewable Energy Laboratory's (NREL's) ResStock and ComStock end-use load shape models. Because such data is unavailable for Puerto Rico, the PR100 team primarily used Miami-Dade County, Florida, as a proxy based on the similarity of weather and input from discussions with members of the PR100 Advisory Group. For example, the total residential load was disaggregated into individual end-uses as shown in Figure 24.

Figure 24: Disaggregating Annual Residential Electricity to End Uses[65]



Energy Efficiency Increases

PR100 adapted baseline and projected technology efficiencies from the Energy Information Administration (EIA's) 2023 Annual Energy Outlook (AEO2023). The 2015 and 2018 "typical" efficiencies were used for the baseline. The Annual Energy Outlook also projects "typical" and "high" efficiencies in 2030, 2040, and 2050. PR100 assumed that these projections represent the minimum required by

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64 Ibid, Figure 68.
65 Ibid, Figure 70.

updated standards and the efficiencies that will be incentivized through EE programs, respectively. The actual values of efficiency data used for the forecast is not provided in the PR100 Study.

Residential Energy Efficiency Measures

The residential customer class-specific measures included in the forecast are summarized in Table 38.

Table 38: Residential Energy Efficiency Measures and Assumptions[66]

End Use	TPP Measures	PR100 Assumptions	Sources/Notes
Cooling	Ductless air conditioner Window air conditioner	Window air conditioner efficiency projections from EIA (2023)67	EIA (2023a) does not list ductless systems (heat pumps or mini splits)
Lighting	ENERGYSTAR LED lighting	Baseline: 50-50 incandescent-LED Natural turnover: 50-50 CFL-LED Incentivized turnover: LED	More than half of homes in each of the 50 U.S. states have at least 50% LEDs (EIA 2020)68
Water heating	Solar water heater Tankless water heater	Baseline and natural turnover: electric resistance tank Incentivized turnover: solar	EIA (2023) has lower efficiencies for tankless than electric tank NREL's Puerto Rico Energy Efficiency Scenario Analysis Tool shows higher consumption for tankless than electric tank
Food services	ENERGYSTAR refrigerator	Baseline: VIEET Natural and incentivized turnover: EIA (2023)69	

3.2.4 Commercial Energy Efficiency Measures

The commercial customer class-specific measures included in the forecast are summarized in Table 39.

Table 39: Commercial Energy Efficiency Measures and Assumptions[70]

End Use	TPP Measures	PR100 Assumptions	Sources/Notes
Cooling	Rooftop AC Chillers	EIA (2023) efficiencies for commercial rooftop AC	ComStock shows that 80% of the cooling electricity in Miami and Hawaii is from packaged rooftop units
Water heating	Water heating	Baseline: electric resistance tank (0.98 EF per EIA [2023]) Incentivized turnover: heat pump (3.9 COP per EIA [2023])	
Food services	Refrigerator	Average of commercial reach-in refrigerators, commercial reach-in freezers, commercial walk-in refrigerators, and commercial walk-in freezers	
Food services	Combination oven	Not modeled	No efficiency information in EIA (2023)

[66] Ibid, Table 18
[67] Energy Information Administration. (2023). Updated Buildings Sector Appliance and Equipment Costs and Efficiencies. Washington, D.C.: U.S. Energy Information Administration. https://www.eia.gov/analysis/studies/buildings/equipcosts/pdf/full.pdf.
———. 2023b. *Electric Power Monthly*, Table 5.3. Average Price of Electricity
[68] Energy Information Administration. (2020). Residential Energy Consumption Survey (RECS): 2020 RECS Survey Data. https://www.eia.gov/consumption/residential/data/2020/.
[69] EIA 2023
[70] PR100 Report, Table 19

End Use	TPP Measures	PR100 Assumptions	Sources/Notes
	Convection oven Fryer Ice machine		
Pumps	Pool pump VFD	Not modeled	

Industrial Energy Efficiency Measures

Although the TPP Business Rebate Program includes savings from industrial and agricultural buildings and commercial buildings, PR100 classified all savings from industrial and agricultural buildings, instead of process loads, as commercial savings.

The PR100 industrial energy savings assumptions draw from the U.S. Department of Energy's Better Plants initiative. Under these assumptions, 1.15% of the manufacturing footprint participates in an energy efficiency program each year, and each participant reduces its annual energy consumption by 25% over 10 years.71

Street Lighting Energy Efficiency Measures

Table 40 shows PR100 assumptions for calculating the electricity savings associated with installing LED streetlights compared to baseline consumption.

Table 40: Street Lighting Electricity Savings Assumptions and Sources[72]

Value	Assumption	Source of Data
350,000	Streetlights to replace	TPP
3.9 years	Time to replace them	TPP
457 kWh/yr	Savings per light that is replaced before 2035	TPP Year 1 savings
628 kWh/yr	Savings per light that is replaced after 2035	Yamada et al. (2019)[73]
16 years	Expected Useful Life (EUL)	DOE, Better Buildings (2021)[74]

[71] U.S. Department of Energy. (2021). Overview: Better Buildings, Better Plants. https://betterbuildingssolutioncenter.energy.gov/sites/default /files/attachments/Better%20Plants%20Program%20Overview%20-%20November%202021.pdf
[72] PR100 Report, Table 20.
[73] Yamada, M., Julie P., Seth S., Kyung L. & Clay E. (2019). Energy Savings Forecast of Solid-State Lighting in General Illumination Applications. *U.S. Department of Energy*. https://doi.org/10.2172/1607661
[74] U.S. Department of Energy. (2021). Overview: Better Buildings, Better Plants. https://betterbuildingssolutioncenter.energy.gov/sites/default /files/attachments/Better%20Plants%20Program%20Overview%20-%20November%202021.pdf

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Share of Turned-Over Stock and Program Participation

PR100 determined the stock turnover rate using the expected useful life of each technology, based on data from AEO2023. For example, if an air conditioner has a 10-year useful life, the model assumes a 10% replacement rate each year.

To account for LUMA EE program participation, PR100 used an "incentivized share," defined as the percentage of the stock turnover that participated in the appropriate program and therefore received an incentive. The initial incentivized share was set so that the sum of the savings for the first two years for each sector equals the projections from the TPP, which covers those two years. Because some TPP programs affect multiple end uses, the projected participation by end use could not be directly inferred from the TPP. The analysis assumes that all end users receive the same share of incentives within each sector. PR100 also assumed that the incentivized shares increase linearly for five years and remain constant throughout the analysis. (The report does not provide a rationale for this assumption.) This approach yielded the following:

- The projected share of annual stock turnover that participated in a residential program starts at 2.7% in FY2022 and grows to 13.5% in FY2026 through FY2051.
- The share of annual stock turnover that participated in a commercial program starts at 7.4% in FY2022 and grows to 37% in FY2026 through FY2051.

Top-Down Energy Efficiency Forecast

Puerto Rico's Energy Efficiency Regulation requires Puerto Rico to achieve 4,744 GWh/year of electricity savings by 2040, based on 30% of PREPA's FY2019 sales.75 The projected savings based on the bottom-up approach do not achieve that goal.

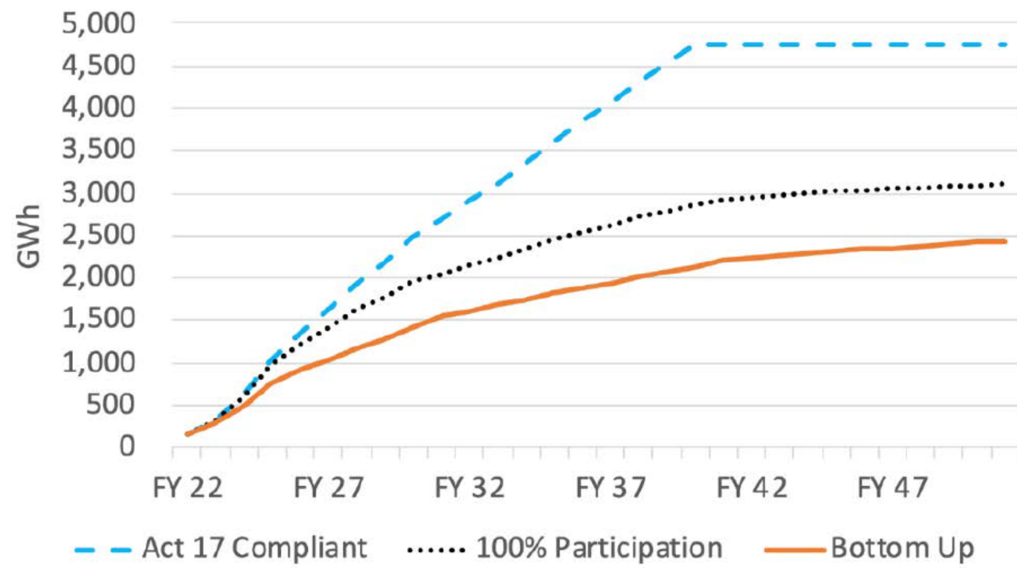
To create a projection that was compliant with the regulations, PR100 first assumed that 100% of residential and commercial systems participated in the EE programs and implemented high-efficiency options.

Because this 100% participation scenario still did not result in the Act 17 target EE savings, PR100 scaled the 100% participation savings for residential and commercial customers even higher so that the FY2040 electricity savings equated to 4,744 GWh. The savings were held constant after FY2040. The PR100 Report notes that the potential way that the savings could be higher than the bottom-up estimates is for the efficiencies of the individual technologies to increase more than projected by AEO, perhaps because of a technological breakthrough. Because such a breakthrough becomes more likely farther into the future, PR100 increased the scaling factor linearly through FY2040, when it reaches about 1,345 GWh. After 2040, they held the savings constant. All sectors were scaled equally.

The resulting annual EE savings, as calculated by PR100, are shown in Figure 25.

[75] Puerto Rico Energy Bureau. (2022). Regulation for Energy Efficiency, 9367. https://energia.pr.gov/wp-content/uploads/sites/7/2022/04/Reglamento-9367-Regulation-for-Energy-Efficiency.pdf

Figure 25: PR100 Energy Efficiency Savings Estimates – Bottom-Up, 100% Participation, and Top-Down (Act 17 Compliant)[76]



Adjusted Energy Efficiency Forecast

As indicated in Figure 25, the PR100 EE savings were forecasted to start in FY2022 based on the original TPP plan.[77] As noted above, the PR100 EE savings adopted the first Year 1 and Year 2 savings (i.e., 2022 and 2023 in the PR100 EE forecasts) from the 2022 TPP filing to the Energy Bureau. However, the approval and implementation of the TPP were delayed, so the first year of savings from the TPP program was FY2024. In addition, the forecasted EE savings for the first two years of the revised TPP78 program (i.e., FY2024 and FY2025 in the revised plan) were also modified in the revised TPP. To develop the EE Forecasts for the IRP, LUMA substituted the modified savings from the first two years of the Revised TPP for the first two years of the EE savings forecast by PR100. LUMA also deferred each year of estimated savings in the PR100 residential and commercial EE forecasts by two years to align with the two-year delay in the implementation of the TPP (i.e., the first year of savings in the TPP was delayed from 2022 to 2024). The forecasts for EE savings measured at the customer meter, which were used in the IRP, are shown in Figure 26. Estimated T&D losses were then added to the values in Figure 26 to reflect the resulting reduction in utility generation required to serve customer loads, which were reduced by the EE savings. The EE forecast values with the T&D losses are provided in Appendix 7.

The EE impact at 100% program acceptance remains unchanged, except for the time shift due to the delay expected in the revised TPP. The top-down (Act 17) forecast is scaled from 100% program participation to reach the target savings of 4,744 GWh in FY2040.

[76] PR100 Study

[77] Motion Submitting Proposed EE/DR Transition Period Plan to the Honorable Puerto Rico Energy Bureau, Puerto Rico Energy Bureau, Case No. NEPR-MI-2022-001. https://energia.pr.gov/wp-content/uploads/sites/7/2022/06/Motion-Submitting-Proposed-EE-DR-Transition-Period-Plan-NEPR-MI-2021-0006.pdf (referred to as TPP (2022) below)

[78] Motion to Submit Revised TPP and Other Information Requested on the Resolution and Order of November 29, 2023, Case No. NEPR-MI-2022-001., https://energia.pr.gov/wp-content/uploads/sites/7/2023/12/20231220-MI20220001-Motion-in-compliance.pdf (referred to as TPP (2023) below)

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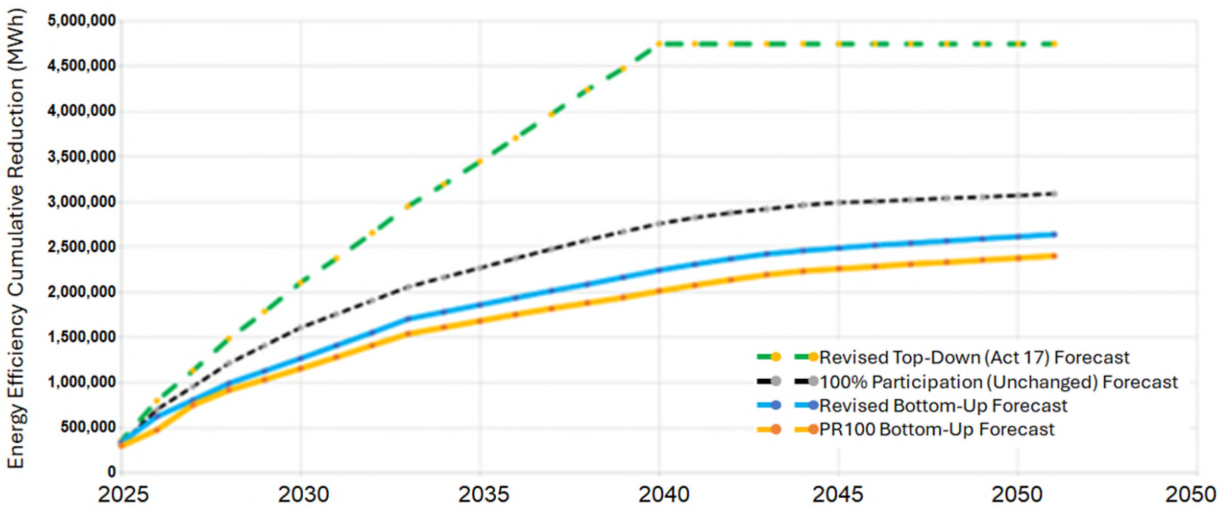
Figure 26: Modified PR100 EE Forecast with Revised TPP Savings



Adjusted EE savings were derived as follows:

- Determine the contribution of TPP (2022) to the PR100 forecast beyond the first two years
    - The projected share of annual stock turnover that participated in a residential program starts at 2.7% in FY2022 and grows to 13.5% in FY2026 through FY2051, and starts at 7.4% in FY2022 and rises to 37% in FY2026 through FY2051 for the commercial program; assume the growth from FY2022 to FY2026 is linear
    - PR100 sets the sum of the savings from LUMA programs for the first 2 years to equal the projections from the TPP; assume the TPP (2022) increase is proportional to the PR100 percentage increase in the first two years
    - Extrapolate beyond the first two years, using the PR100 percentages
    - Note this preserves the measure lifetimes assumed in PR100; no adjustments have been made due to possible changes in the portfolio of measures
- Determine the contribution of TPP (2023) to the PR100 forecast beyond the first two years
    - Repeat the above process, adjusting the timeline to the TPP (2023) schedule, postponing Year 1 of the program to FY2024
- Add the difference between the TPP (2023) forecast and the TPP (2022) forecast to the original PR100 forecast
- Use industrial and streetlight savings as specified in PR100, without changing the corresponding FY.

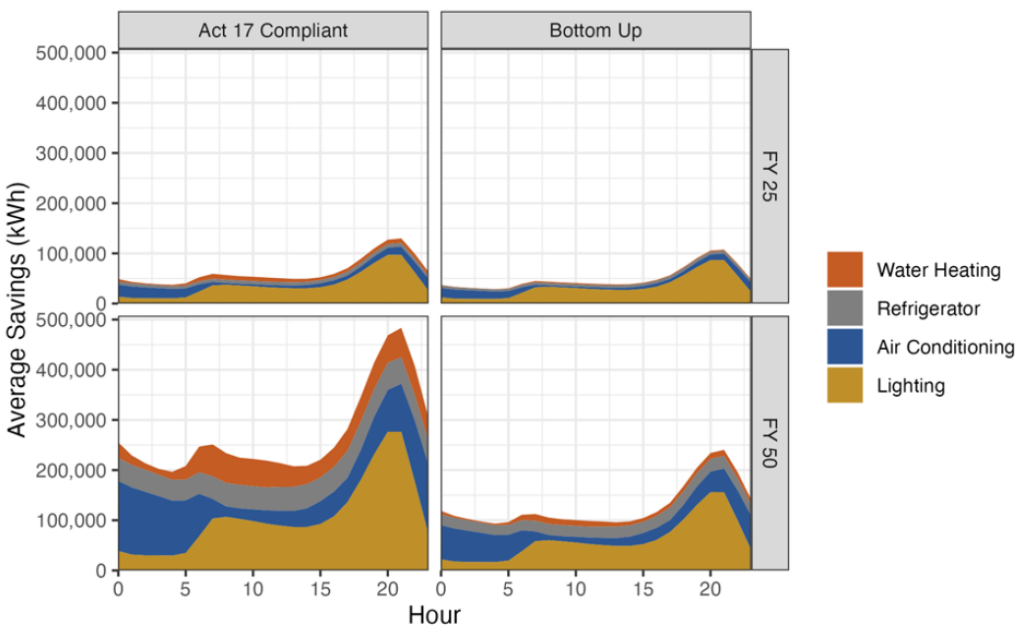
Load Shape Changes Due to EE

The load reduction due to EE will not be uniform over a day. The impacted end-uses (e.g., space conditioning, water heating, lighting) have different baseline load shapes and will experience different magnitudes and timings of EE-induced changes. To obtain this level of detail, getting a baseline load shape for each end-use to be targeted by EE is necessary.

As discussed in the Annual End-Use Consumption subsection above, Puerto Rico's baseline data is unavailable, so PR100 used Miami-Dade County, Florida, as a proxy. It was supplemented by selected U.S. Virgin Islands Energy Efficiency Tool (VIEET) data.79 Deriving the load shapes in this manner is much more challenging than estimating aggregate annual uses. Even though the totals may be similar, the disaggregated load shapes reflect working hours, customs, preferences, etc.

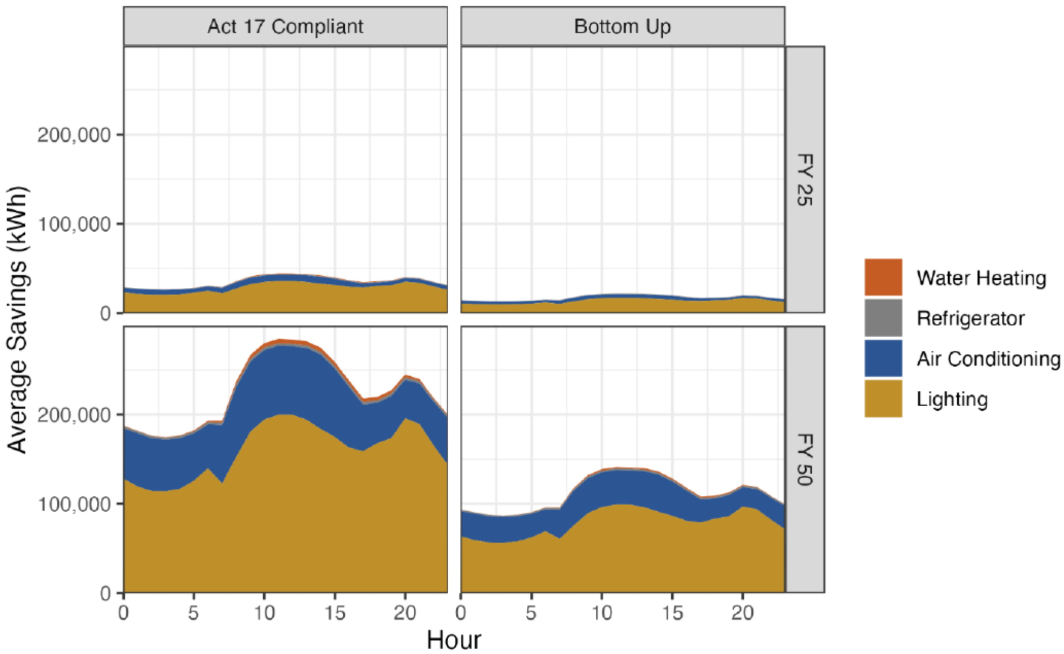
Figure 27 and Figure 28 show the average hourly savings for the top-down and bottom-up forecasts in FY2025 and FY2050 for the residential and commercial sectors, respectively. The savings peak at 9 p.m. in residential buildings, a bit before the overall residential peak, because lighting contributes a large share of the savings. However, the savings are still substantial later at night.

Figure 27: Average Hourly Electricity Savings – Residential[80]



[79] This tool is not publicly available.
[80] PR100 Report, Figure 77

Figure 28: Average Hourly Commercial Electricity Savings[81]



In commercial buildings, lighting upgrades yield the most savings, with some contribution from air conditioning. The PR100 team believes the cooling savings remain high overnight because of their method for inferring the commercial cooling load shape. The baseline Puerto Rico commercial load shape from FY2018 is flatter than ComStock's for Miami-Dade County, and PR100 attributed the difference to cooling.

Utility Program Costs

PR100 calculates program costs using a per-kWh value derived by averaging the estimates for the two years in the TPP. For the first year, these values are $0.37/kWh of annual savings for residential and $0.46/kWh of annual savings for commercial (program cost/annual savings from the TPP).

PR100 did not include program costs for street lighting and industrial process loads. They assumed the streetlighting projects were funded by the Federal Emergency Management Agency (FEMA) rather than by LUMA.82 PR100 did not include program costs for the industrial sector because TPP programs that address commercial and industrial savings were accounted for in the commercial sector. LUMA did not offer any programs only for industrial customers. The industrial process load savings modeled by PR100 are based on a voluntary initiative that does not receive program funds.

The top-down forecast designed to comply with Act 17 requirements is very aggressive, given that the target for 30% savings was initially established in Act No. 57 of May 27, 2014.[83] This EE savings target of 30% by 2040 was subsequently absorbed in Act 17, but the first EE programs were only implemented,

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[81] Ibid, Figure 78

[82] “Motion Submitting Proposed EE/DR Transition Period Plan to the Honorable Puerto Rico Energy Bureau.” Puerto Rico Energy Bureau. https://energia.pr.gov/wp-content/uploads/sites/7/2022/06/Motion-Submitting-Proposed-EE-DR-Transition-Period-Plan-NEPR-MI-2021-0006.pdf

[83] Puerto Rico Energy Transformation and RELIEF Act” (Act 57-2014, as amended)

and the first savings were achieved in 2024. It has been 10 years since the original legislation setting the 30% EE savings target was passed; however, the target data for achieving the savings has remained unchanged by 2040.

Figure 29 compares the capacity reduction caused by implementing the base energy efficiency and the Act 17 energy efficiency forecasts.

Figure 29: Graphic Comparison of LUMA's Base and Act 17 Energy Efficiency Capacity Savings Forecasts (MW)

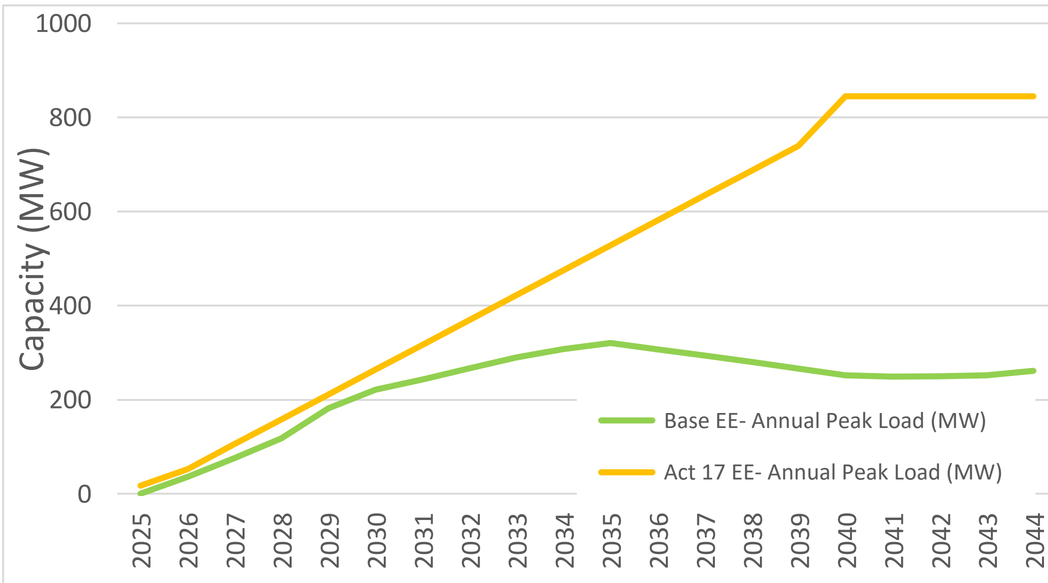

Figure 30 compares the base EE and the Act 17 EE energy savings (in GWh).

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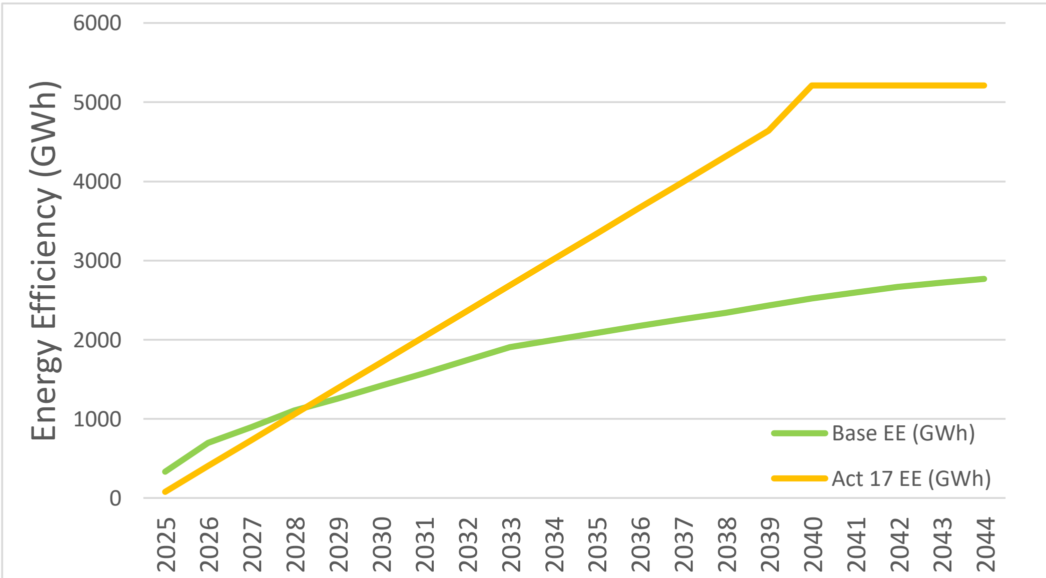
Figure 30: Graphic Comparison of LUMA's Base and Act 17 Energy Efficiency Energy Savings Forecasts (GWh)



3.2.5 Demand Response Forecast

As with the energy efficiency forecast and other forecast elements, LUMA had planned to use a DR forecast developed during the PR100 Study. However, the PR100 Study did not include the development of a DR forecast in its original scope. Even with multiple requests from LUMA during the PR100 Study process, the PR100 project leaders could not add it to the project scope. After learning that the PR100 Study will not include a DR forecast, LUMA contracted with GH to prepare a high-level preliminary DR Potential Study. The GH DR Potential Study can be found in Appendix 7. This section draws from the GH DR Potential Study without further citation.

To develop the DR Potential estimate, GH was able to leverage the previous EE/DR modelling work undertaken by NREL for Puerto Rico outside of the PR100 Study. The NREL Puerto Rico Demand Response Impact and Forecast Tool2 (PR-DRIFT) was modified by GH to reflect various methodological refinements that GH typically employs in DR potential studies that it has completed for multiple clients in the mainland USA and other countries.

Due to relatively limited data available for Puerto Rico, GH leveraged previous DR analysis undertaken by GH in the development of the LUMA EE/DR Transition Period Plan (TPP) and focused its research and analytic efforts on those DR measures that are most relevant for Puerto Rico and are expected to provide the most significant long-term impact. The GH DR Potential Study included analysis and estimates for DR programs focused on four areas and 14 programs.

- Residential
    - Residential Time of Use (TOU) Rates
    - Residential Critical Peak Pricing

- Residential HVAC Direct Load Control
- Residential Water Heating Direct Load Control
- Behind-the-Meter (BTM) Battery Dispatch

▪ Commercial Demand Response Assumptions

- Commercial TOU Rates
- Commercial Critical Peak Pricing
- Commercial HVAC Curtailment

▪ Industrial Demand Response Assumptions

- Industrial TOU Rates
- Industrial Load Curtailment
- Industrial Critical Peak Pricing

▪ Electric Vehicle Demand Response Assumptions

- EV TOU Rates
- EV Managed Charging
- EV V2X (Vehicle-to-Everything)

The GH DR Potential Study results show a potential demand reduction of 686 MW in CY 2044 at an annual cost of $ 186 million.

The values that result from an optimal DR deployment, as well as the DR reduction with focused measures for snapshot years, are showcased on Table 41. In the snapshot years from 2025 to 2035, optimal DR is unnecessary as the top 40 hours are enough to distribute the peak reduction in that year. However, less load must be reduced at peak hours in later years. Starting from the 2040 snapshot year, optimal DR deployment prevents the formation of a new peak while spreading the DR savings out across the top approximately 200 hours.

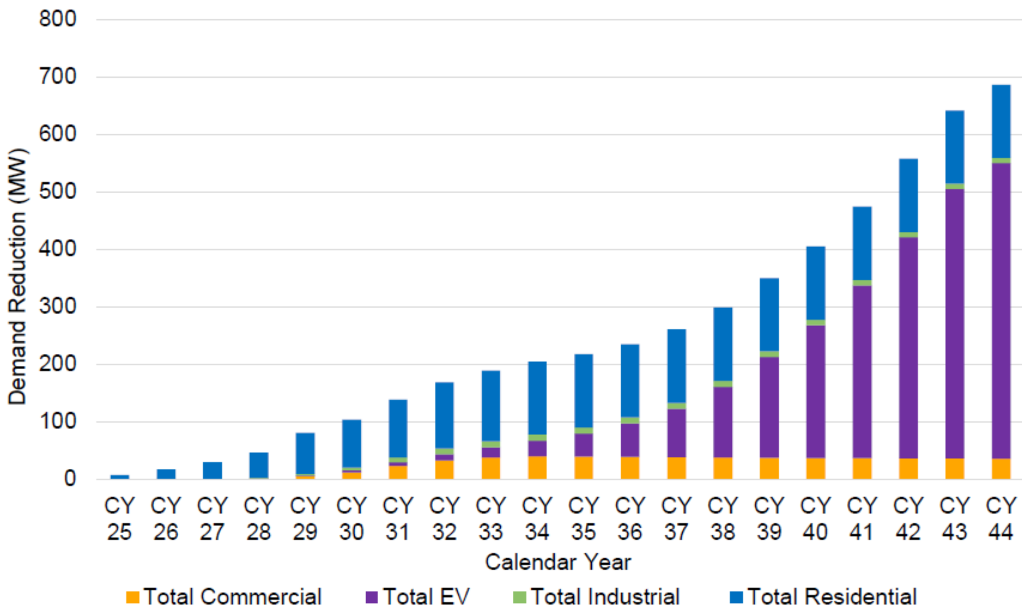
Table 41: Demand Response Reduction with "Optimal" and Focused Deployment

Year	Demand without DR (MW)	"Optimal' DR reduction (MW)	DR reduction focused on the top 40 hours (MW)
2025	2,916	7	7
2030	2,978	104	104
2035	2,940	217	217

Year	Demand without DR (MW)	"Optimal' DR reduction (MW)	DR reduction focused on the top 40 hours (MW)
2040	2,993	291	405
2044	3,116	380	686

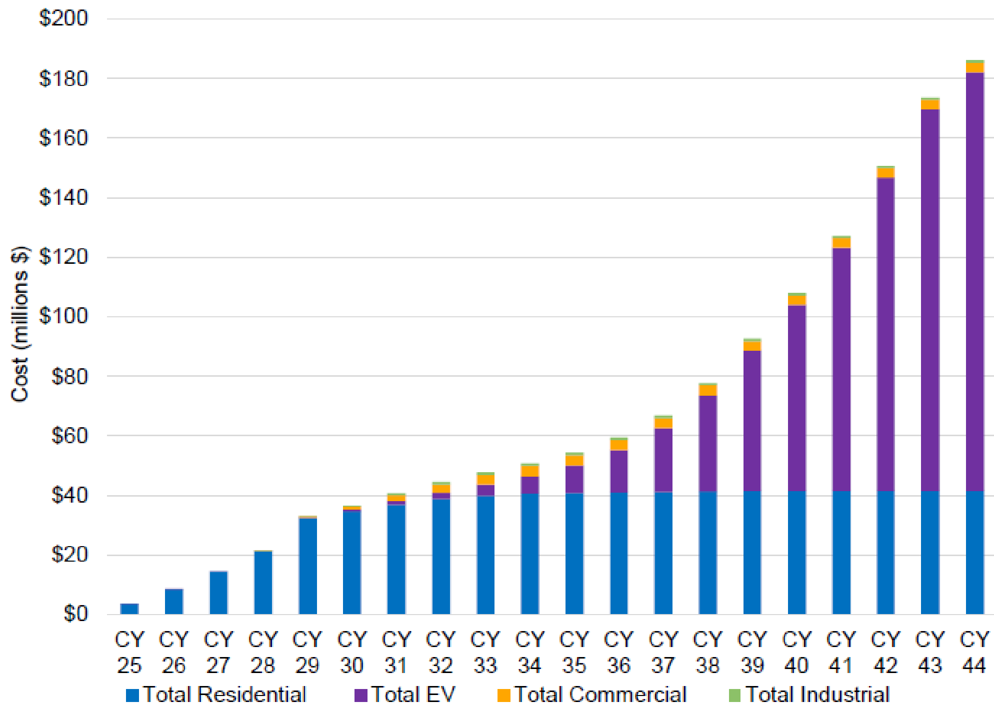
The analysis conducted on the GH DR Potential Study shows that the residential sector has the highest potential savings, followed by commercial, industrial, and EV sectors. However, due to the expected increase in EVs and participation in EV-related measures, EV becomes the sector with the highest potential savings. Figure 31 below shows the potential demand reduction by sector over the planning period.

Figure 31: Demand Reduction over Forecast Period by Sector



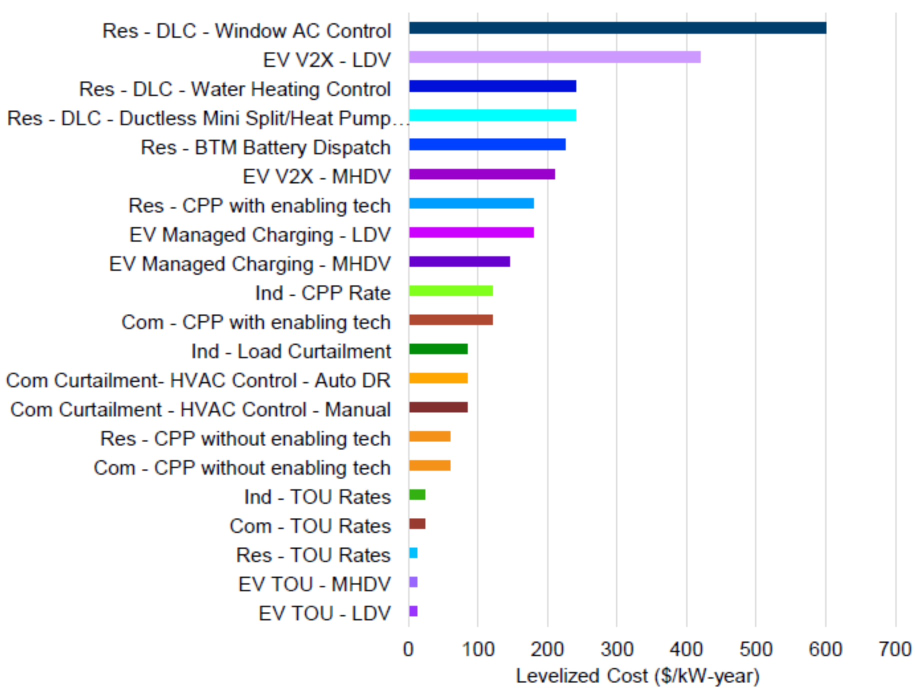
The cost for each sector of implementing the different DR measures is presented in Figure 32. Like the potential savings, the residential sector has the highest costs over the first few years, while over time EV becomes the sector with the highest associated cost.

Figure 32: Cost over Forecast Period by Sector



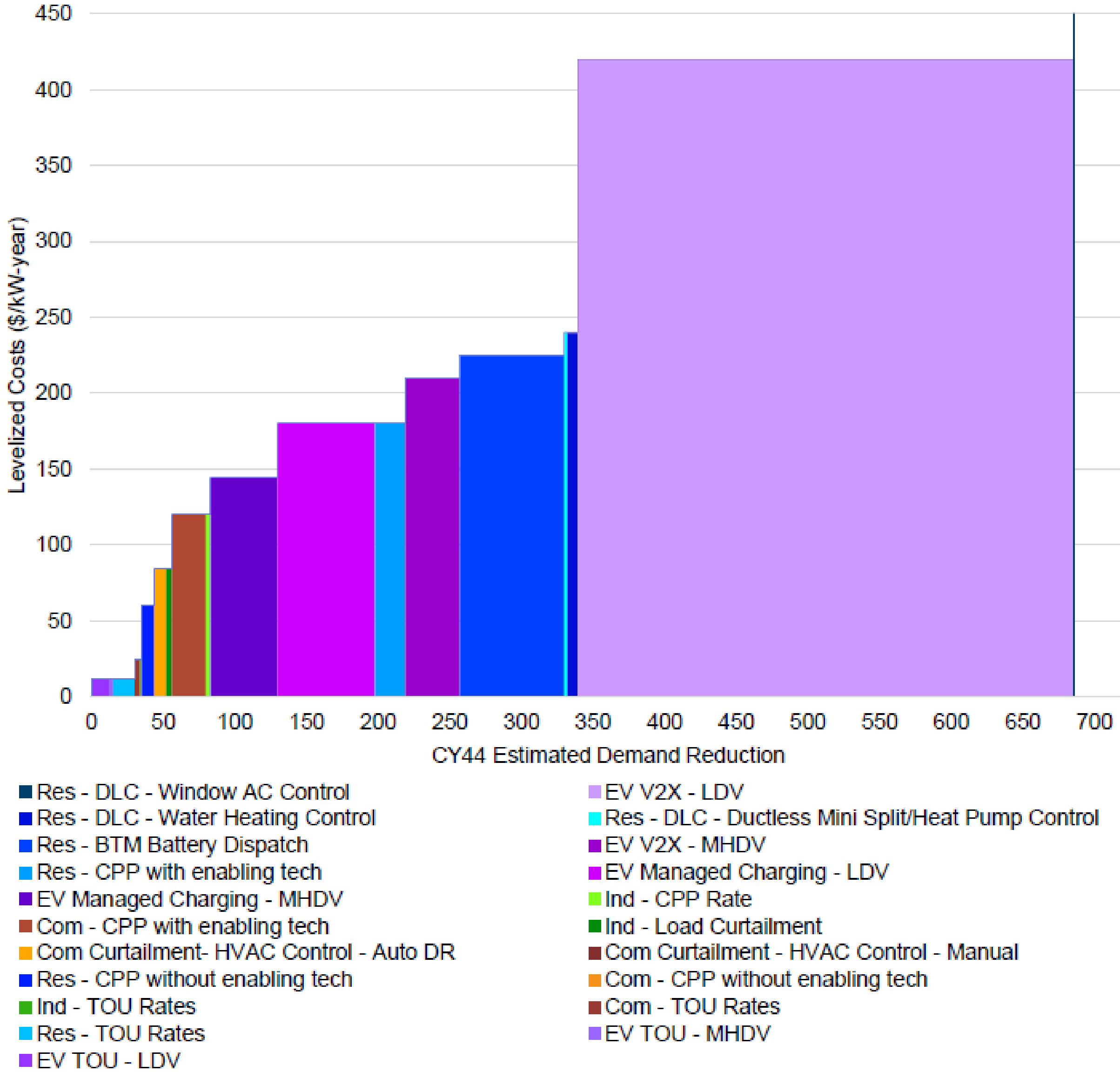
The comprehensive list of levelized cost values used is presented in Figure 33, including the 20% Puerto Rico Cost Adder.

Figure 33: Levelized Cost by Measure ($/kW-year)



Lastly, Figure 34 shows the DR Supply Stack for CY 2044. Here, it can be appreciated that the most significant contributors to DR capacity for CY 2044 are BTM Battery Dispatch and V2X, but both are relatively high-cost measures. Excluding these and other high-cost measures, there is about 200 MW capacity under $200/kW-year in CY 2044.

Figure 34: Supply Stack in Calendar Year 2044



3.2.6 Electric Vehicle Charging Load

The transportation sector is the largest U.S. emitter of CO2, responsible for almost 30% of U.S. emissions in 2022, followed by electric power generation. Light-duty trucks — SUVs, minivans, and pickup trucks — accounted for 37% of the sector's emissions in 2022, followed by medium- and heavy-duty trucks (23%)

and passenger cars (20%).[84] Collectively, these road vehicles account for 80% of the U.S. transportation sector's emissions, compared to 20% total from commercial aircraft (7%), other aircraft (2%), pipelines (4%), ships and boats (3%), and rail transport (2%). As a result, most of the efforts to curtail greenhouse gas emissions focus on electrifying transportation.

On-road vehicles are assigned to specific categories, termed classes. These classes, 1-8, are based on gross vehicle weight rating (GVWR), the vehicle's maximum weight as specified by the manufacturer. Further information on this classification is provided in the medium- and heavy-duty vehicles(MHDV) section. Most energy, environmental, and regulatory analyses are carried out in three categories:

- Light-duty vehicle (LDV): Classes 1–2a (passenger cars and light-duty trucks)
- Medium-duty vehicle (MDV): Classes 2b–3
- Heavy-duty vehicle (HDV): Classes 4–8

Most vehicles used for personal transportation are in the LDV category, while those used for business, commerce, and industrial purposes tend to fall in the MHDV category. Because of the significant difference in the markets, uses, and resulting charging loads, LUMA addresses the two market segments separately.

Light-Duty Vehicles in Puerto Rico

Until April 2023, Puerto Rico had a national fleet of 2.2 million vehicles. With 146 vehicles per street mile and 4,300 vehicles per square mile, Puerto Rico is considered to have the most cars per square mile in the world.85 The US Federal Highway Administration estimates that, in 2022, the number of vehicle miles traveled (VMT) in Puerto Rico amounted to 14,929, or about 6,800 miles/vehicle/year.86 Ninety percent (90%) of this mileage is considered urban traffic, one factor that impacts vehicle efficiency.

As of October 2024, LUMA estimated that less than 1% of Puerto Rico's approximately 2.2 million cars were electric.87 LUMA believes that making it easier for its customers to use electric vehicles (EVs) is critical to Puerto Rico's clean energy future. Building the right infrastructure can make this possible.

Electric Vehicle Charing Forecast

LUMA expected to use the LDV results of the PR100 study. Unfortunately, several issues with the EV impact estimates became obvious, and LUMA decided to correct some of these for its IRP forecast. The issues include:

- The analysis randomly defined the average efficiency of the vehicle over the total distance using a uniform distribution with a minimum of 2.4 km/kWh to a maximum of 5.6 km/kWh. This translates into 1.5-3.5 miles/kWh, which is much too low for the recent past or expected future and would overestimate EV load impacts and the grid upgrade expenditures.

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[84] "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2022," U.S. Environmental Protection Agency, EPA 430R-24004; https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2022

[85] Global Fleet; https://www.globalfleet.com/en/wikifleet/puerto-rico

[86] Highway Statistics Series, January 2024; https://www.fhwa.dot.gov/policyinformation/statistics/2022/vm2.cfm (This data includes all vehicle types, not just LDVs However, as seen in Table WM-4, LDVs account for about 95% of the miles

[87] Progreso de LUMA; https://progresodelumapr.com/en/our-future/sustainable-energy-transformation/electric-vehicles/

- The velocity was assumed to be a constant 30 miles/hr. Again, this probably contributes to further underestimating EV efficiency and overestimating the load impact.
- Although PR100 provided the results by municipalities, it appears that the uncertainties are such that, while there is reasonable confidence in the Puerto Rico-wide results, no geographical details should be excessively relied on.

To correct this, LUMA used a more appropriate efficiency value for LDVs. The details of LUMA's approach are described below.

Electric Vehicle Efficiency Drivers

Measuring Electric Vehicle Efficiency

Since EVs do not use gasoline, the familiar metric of miles per gallon cannot be applied to EVs. Instead, EVs are rated by the Environmental Protection Agency (EPA) in terms of miles per gallon-equivalent (MPGe), which is the number of miles an EV travels on an amount of electrical energy equivalent to the energy in a gallon of gasoline. This metric directly compares energy efficiency between EVs and gasoline vehicles. EVs generally have a much higher energy efficiency than gasoline vehicles since electric motors are much more efficient than gasoline engines.

To make things slightly more complicated, not all the kWh in EV batteries are usable, as a degree of 'buffering' helps maintain their health. This means that an 80-kWh battery might have a capacity of 77 kWh, the figure used in efficiency calculations.

How EV efficiency figures are quoted also varies; some databases list miles per kWh, and some kWh per 100 miles. LUMA selected miles per kWh, which is closest to the familiar miles per gallon metric.

Compliance data are measured using EPA city and highway test procedures (the "2-cycle" tests), and fleetwide averages are calculated by weighting the city and highway test results by 55% and 45%, respectively.

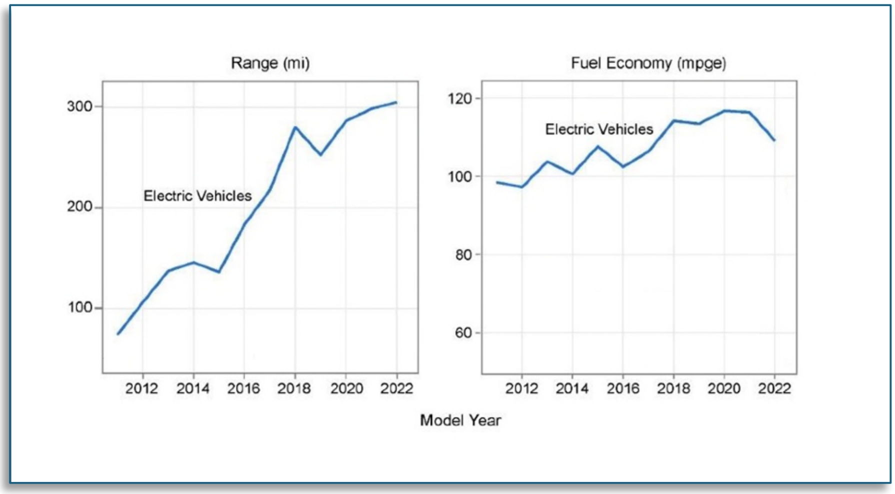
EPA estimated real-world data, which is measured using additional laboratory tests to capture a broader range of operating conditions (including hot and cold weather, higher speeds, and faster accelerations) encountered by an average driver. This expanded set of tests is referred to as "5-cycle" testing. City and highway results are weighted 43% by city and 57% by highway.

Efficiency of New Electric Vehicles

The average LDV EV fleet efficiency is shown in Figure 35. As shown in Figure 35, in model year 2022, the average new EV range was 305 miles, or more than four times the range of an average EV in 2011. At the same time, compared to 2021, the fuel economy of average new EVs fell, mostly due to the introduction of larger vehicles with lower overall fuel economy ratings. A further decline was expected for 2023. However, contrary to expectations, the EV fuel economy more than recovered in 2023.[88].

[88] See, for example https://www.epa.gov/automotive-trends/explore-automotive-trends-data

Figure 35: Range and Fuel Economy of the U.S. Electric Vehicle Fleet[89]



The share of SUVs in the fleet illustrates the growth in larger vehicles. Since 1975, the production share of SUVs in the United States has increased in all but 10 years, and in 2021, it accounted for more than 54% of all vehicles produced.90 This includes both the car and truck SUV vehicle types.

The EPA Auto Trends report also shows the average new vehicle weight for all vehicle types since 1975. From model year 1975 to 1981, average vehicle weight dropped 21%, from 4,060 pounds per vehicle to about 3,200 pounds; this was likely driven by both increasing fuel economy standards (which, at the time, were universal standards, and not based on any vehicle attribute) and higher gasoline prices.

From model year 1981 to model year 2004, the trend reversed, and average new vehicle weight began to slowly but steadily climb. By 2004, the average weight of a new vehicle had increased 28% from the model year 1981 and reached 4,111 pounds per vehicle, partly because of the increasing truck share. The average vehicle weight in 2022 was about 5% above 2004, at the highest point on record, at 4,303 pounds. Heavier vehicles require more energy to move than lower-weight vehicles and, if all other factors are the same, will have lower fuel economy and will reduce the fleet average

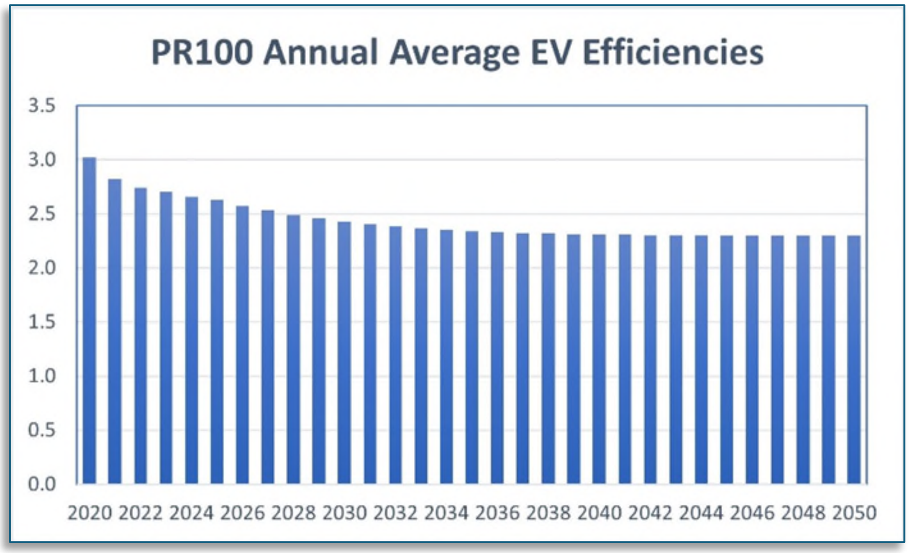
Estimating Electric Vehicle Efficiency for Puerto Rico

Figure 36 shows annual LDV EV efficiency for Puerto Rico as estimated in the PR100 study. Since the efficiencies are determined stochastically, no rationale is provided for the decline over the years.

[89] "The 2023 EPA Automotive Trends Report: Greenhouse Gas Emissions, Fuel Economy, and Technology since 1975," U.S. EPA EPA-420-R-23-033, December 2023; https://www.epa.gov/system/files/documents/2023-12/420r23033.pdf

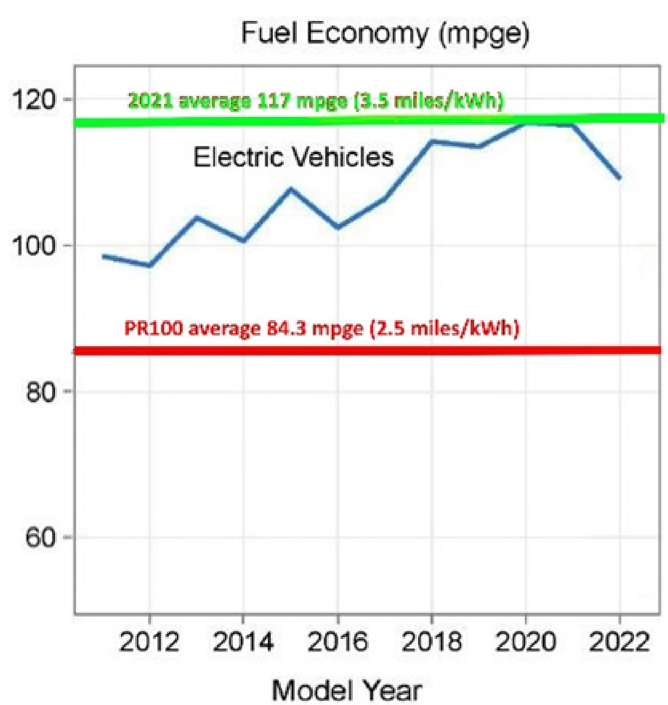
[90] ibid

Figure 36: PR100 Light Duty Vehicle Energy Efficiency (kWh/mile) Estimate



Instead, the PR100 project should have used the average of 2021 fuel economy, 3.5 miles/kWh (see Figure 37).

Figure 37: PR100 Fuel Economy Assumptions versus EPA Data (MGPe)



Since LUMA is now converting the PR100 estimate with a view to the future, its analysis uses an efficiency value of 3.6 miles/kWh.

There are several reasons for expecting EV efficiency in Puerto Rico to be higher than the averages on the mainland of the U.S. These reasons include:

- Driving patterns – shorter distances and higher congestion
  - Puerto Rico is an island with limited travel distances, so the daily mileage is likely to be lower and the share of stop-and-go (city) driving higher than mainland averages
  - In general, EV efficiency in city driving is much higher than highway efficiency. For example, the average 2021 data shows city driving efficiency to be 123 MPGe vs highway driving of 110 MPGe. If driving in Puerto Rico is closer to city driving than on the mainland of the U.S., this would increase the average efficiency of Puerto Rican driving.
- Ambient temperature impact – warmer than the mainland average
  - EV efficiency and range decrease at higher temperatures. This, again, would result in a relative increase in EV efficiency in Puerto Rico compared to the mainland.

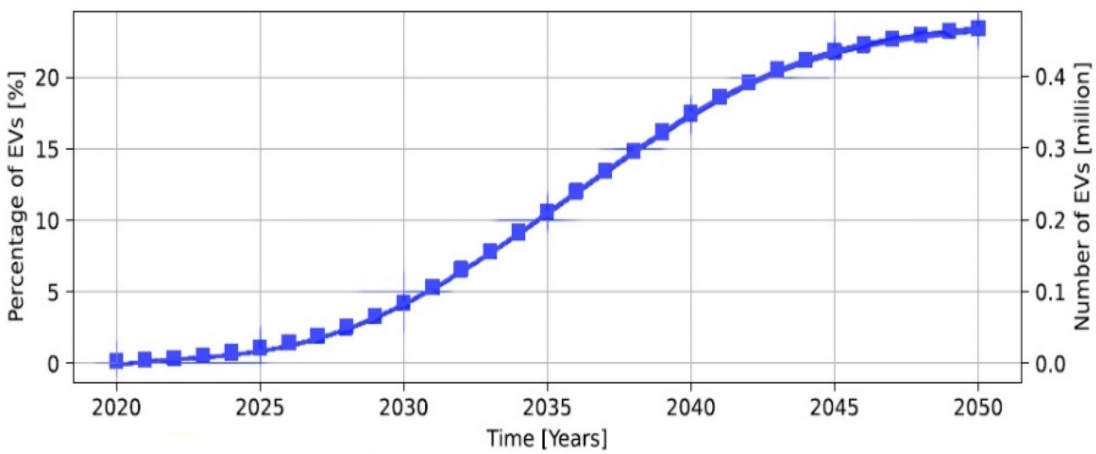
As more data from the LUMA EV TOU pilot becomes available, many questions about Puerto Rico's driving behaviors are expected to be answered.[91]

Electric Vehicle Market Share in Puerto Rico

PR100 provides a forecast of Puerto Rico EV adoption rates, reproduced as Figure 38. Adoption rates are usually interpreted as a fraction of new car sales, thus indicating the incremental growth of the EV fleet. However, the PR100 graphic implies that the adoption rate of 23.2% in 2050 corresponds to almost 470,000 vehicles, which is about four times the annual LDV sales in Puerto Rico. As a result, LUMA must assume that the figures shown by PR100 represent the fraction of vehicles on the road each year. For example, the current (mid-2024) fraction of EVs in the U.S. is about 10% of all LDVs, while the market share (adoption rate) is below 7%.

[91] LUMA. (2023). Puerto Rico's Electric Vehicle Adoption Plan. *Puerto Rico Energy Bureau*, (May 1). NEPR-MI-2021-0013; https://energia.pr.gov/wp-content/uploads/sites/7/2023/05/20230501-Motion-to-Submit-Final-Phase-I-EV-Plan-in-Compliance-with-Resolution-and-Order-of-January-132023.pdf

Figure 38: PR100 Estimate of Light-Duty EVs in Puerto Rico's Vehicle Fleet, 2020−2050



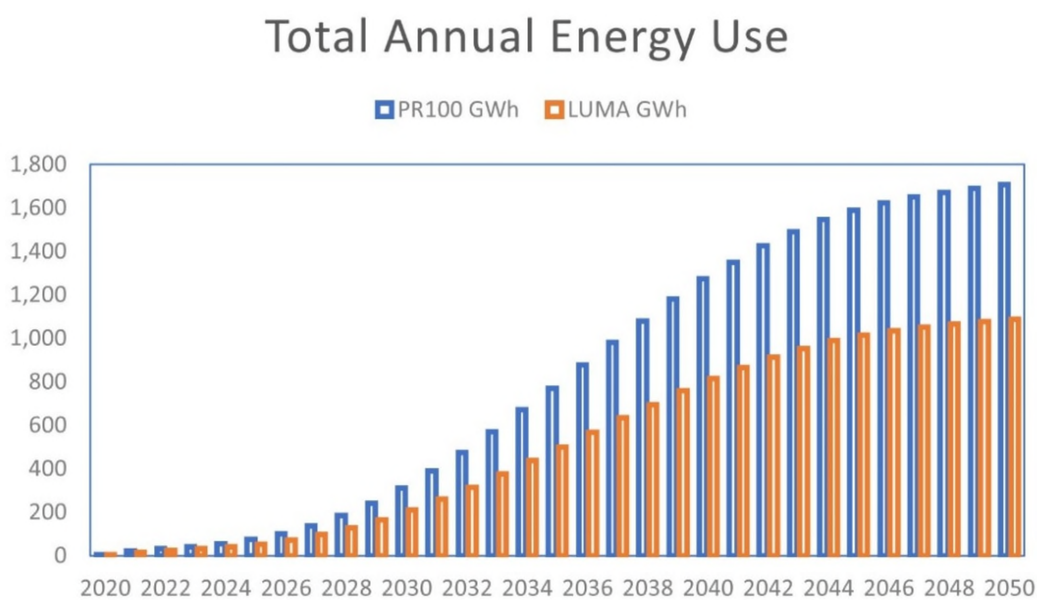
The vehicle count shown in the context of LDV market penetration is inconsistent with the mileage and energy use provided in a separate analysis in the PR100 study. Using vehicle counts from Figure 38 above, the electricity use per car becomes too high, ~10 kWh/day per car. Perhaps the mileage and the corresponding electricity use figures were derived separately from the EV diffusion estimates. PR100 couldn't rely on existing forecasts or vehicle registrations to forecast EV sales and counts. Using Louisiana as a proxy, they decided to correlate vehicle counts with income levels. Nevertheless, it is unclear why the market appears to saturate at about 25% of the fleet (based on Louisiana saturation at about 60%).

Despite these questions, LUMA decided to use the PR100 vehicle counts until the assumptions can be refined and modified appropriately so a new Puerto Rico EV forecast can be developed.

Modified Puerto Rico Electric Vehicle Charging Load Forecast

All the efficiencies were revised to a constant 3.6 miles/kWh. To illustrate the impact of this adjustment, Figure 39 shows the PR100 original and the revised annual electricity used in PR for EV charging. LUMA assumed the same EV adoption rates as PR100.

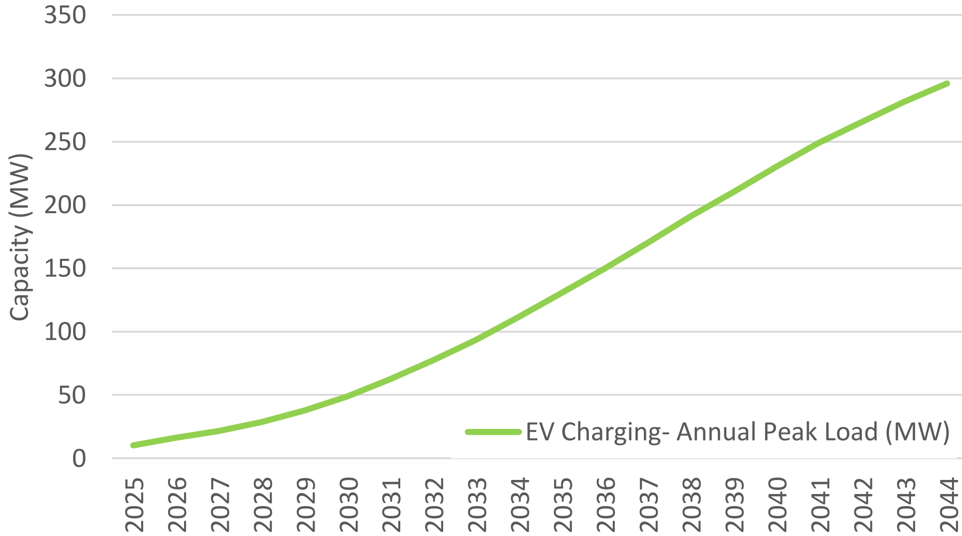
Figure 39: Annual Electricity Use for Light-Duty Vehicle Charging in Puerto Rico



This change results in a substantial decrease in the expected impact of EV charging on PR load growth compared to the PR100 forecast.

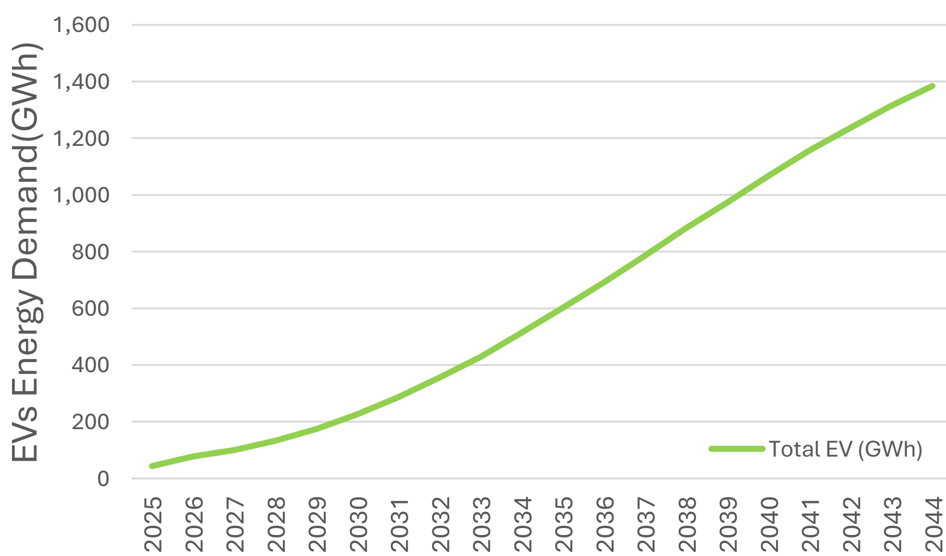
Figure 40 showcases LUMA's impact on the system peak load derived from EVs at peak hour (21:00 hours). This impact includes all types of EVs, including LDV (residential, commercial, and industrial) and MHDV (commercial and industrial), considering that the vehicles are not being charged in workplaces and considering the losses impact on the system generator.

Figure 40: LUMA's Electric Vehicle System Peak Load Impact (MW)



In addition, Figure 41 showcases the impact on the energy demand used for the 2025 IRP modeling. Similar to the peak load impact, this forecast accounts for all types of EVs, considering that the vehicles are not being charged in workplaces and considering the losses impact on the system generator.

Figure 41: LUMA's Electric Vehicle Energy Demand Increase Forecast for Electric Vehicles (GWh)



Electric Vehicle Charging Load Profiles

PR100 used two unmanaged charging load profiles adopted from an early study; see Figure 42. One profile assumes that some or all charging occurs at the workplace, while the other assumes all charging occurs at home. Since both profiles are fictitious and unmanaged, using them to assess peak T/D/G impacts does not provide meaningful insights.

Figure 42: Assumed Load Profile Components in the PR100 Study

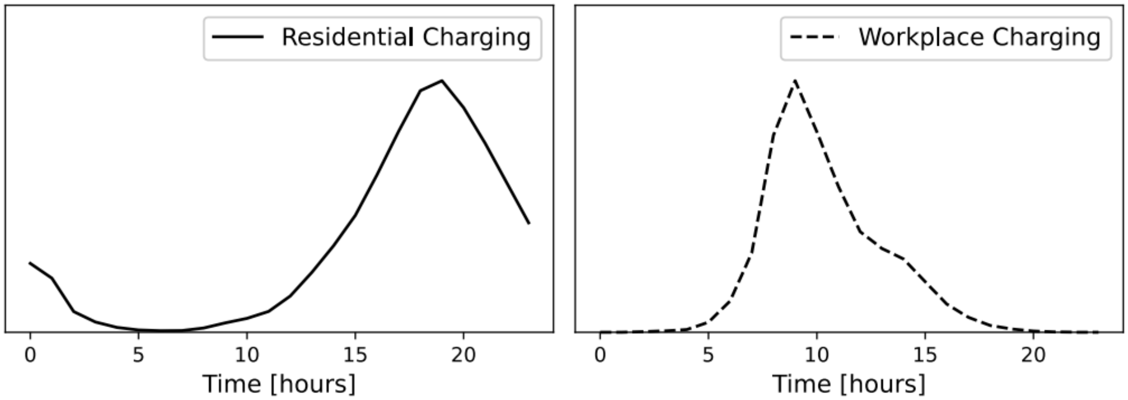


Figure 84. Two light-duty EV unmanaged charging profiles assumed to occur at residential locations (left) and places of work (right)

Observations

LUMA has derived the revised electricity load impact expected from the light-duty EV adoptions assumed in the PR100 study. The revised increase in estimated electricity use ranges from about 40 GWh in 2024 to about 1,100 GWh in 2050.

Medium- and Heavy-Duty Vehicles- Introduction

Although heavy-duty trucks make up only 1% of all vehicles, their emissions account for 25% of all vehicle emissions.

Battery-electric trucks have a higher energy efficiency ratio (EER) than diesel trucks, with an estimated EER of 2.7 compared to diesel trucks. Battery-electric trucks are about 3.5 times more efficient at highway speeds, while at lower speeds, they can be 5 to 7 times more efficient.92 Electric trucks revolutionize vehicle power and fleet management through enhanced interoperability and data storage capabilities. Advanced telematics systems enable real-time tracking of vehicle performance, battery health, and charging status. This data empowers fleet managers to optimize routes, reduce downtime, and maximize energy efficiency.

Worldwide sales of electric trucks increased 35% in 2023 compared to 2022,93 meaning that total sales of electric trucks surpassed electric buses for the first time, at around 54,000. China is the leading market for electric trucks, accounting for 70% of global sales in 2023, down from 85% in 2022. In Europe, electric truck sales increased almost threefold in 2023 to reach more than 10,000 (>1.5% sales share). The United States also saw a threefold increase, though electric truck sales reached just 1,200, less than 0.1% of total truck sales.

North America emphasizes the medium-duty truck market, which accounts for more than 60% of all models. New brands such as Rizon (Daimler Truck Group) are targeting the electric medium-duty

[92] California Air Resources Board. (2017). Battery-Electric Truck and Bus Energy Efficiency Compared to Conventional Diesel Vehicles. https://ww2.arb.ca.gov/resources/documents/battery-electric-truck-and-bus-energy-efficiency-compared-conventional-diesel

[93] Electric Vehicles Initiative. (2024). Global EV Outlook 2024. *International Energy Agency*, (April). https://www.iea.org/reports/global-ev-outlook-2024

segment in North America, where, despite their higher upfront costs, electric trucks are already competitive with diesel trucks in terms of total cost of ownership, especially when charged at the depot as opposed to higher-cost public charging. Costs are even more competitive when factoring in incentives available in the United States and Canada. Though the United States and Canada also have policy incentives targeting buses, they have relatively small public transport markets. Consequently, buses suitable for urban public transport make up just over 10% of all models. Instead, original equipment manufacturers (OEMs) have targeted the school bus niche, producing nine different models, excluding minibuses.

Vehicle weight classes are defined by the Federal Highway Administration and are used consistently throughout the industry. These classes, 1-8, are based on gross vehicle weight rating (GVWR), the vehicle's maximum weight, as specified by the manufacturer. GVWR includes total vehicle weight plus fluids, passengers, and cargo. The Federal Highway Administration categorizes vehicles as Light-Duty (Class 1-2), Medium-Duty (Class 3-6), and Heavy-Duty (Class 7-8). EPA defines vehicle categories, also by GVWR, for emissions and fuel economy certification. These categories are summarized in Figure 43.

Figure 43: Vehicle Weight Classes and Categories

Gross Vehicle Weight Rating (lbs)	Federal Highway Administration		US Census Bureau
	Vehicle Class	GVWR Category	VIUS Classes
> 6,000	Class 1: < 6,000 lbs	Light Duty < 10,000 lbs	Light Duty < 10,000 lbs
10,000	Class 2: 6,001 – 10,000 lbs		
14,000	Class 3: 10,001 – 14,000 lbs	Medium Duty 10,001 – 26,000 lbs	Medium Duty 10,001 – 19,500 lbs
16,000	Class 4: 14,001 – 16,000 lbs		
19,500	Class 5: 16,001 – 19,500 lbs		
26,000	Class 6: 19,501 – 26,000 lbs		Light Heavy Duty 19,001 – 26,000 lbs
33,000	Class 7: 26,001 – 33,000 lbs	Heavy Duty > 26,001 lbs	Heavy Duty > 26,001 lbs
> 33,000	Class 8: > 33,001 lbs		

Gross Vehicle Weight Rating (lbs)	EPA Emissions Classification			
	Heavy Duty Vehicle and Engines			Light Duty Vehicles
	H.D. Trucks	H.D. Engines	General Trucks	Passenger Vehicles
< 6,000	Light Duty Truck 1 & 2 < 6,000 lbs	Light Light Duty Trucks < 6,000 lbs	Light Duty Trucks < 8,500 lbs	Light Duty Vehicle < 8,500 lbs
8,500	Light Duty Truck 3 & 4 6,001 – 8,500 lbs	Heavy Light Duty Trucks 6,001 – 8,500 lbs		
10,000	Heavy Duty Vehicle 2b 8,501 – 10,000 lbs	Light Heavy Duty Engines 8,501 – 19,500 lbs	Heavy Duty Vehicle Heavy Duty Engine > 8,500 lbs	Medium Duty Passenger Vehicle 8,501 – 10,000 lbs
14,000	Heavy Duty Vehicle 3 10,001 – 14,000 lbs			
16,000	Heavy Duty Vehicle 4 14,001 – 16,000 lbs			
19,500	Heavy Duty Vehicle 5 16,001 – 19,500 lbs			
26,000	Heavy Duty Vehicle 6 19,501 – 26,000 lbs	Medium Heavy Duty Engines 19,501 – 33,000 lbs		
33,000	Heavy Duty Vehicle 7 26,001 – 33,000 lbs			
60,000	Heavy Duty Vehicle 8a 33,001 – 60,000 lbs	Heavy Heavy Duty Engines Urban Bus > 33,001 lbs		
> 60,000	Heavy Duty Vehicle 8b > 60,001 lbs			

Medium- and Heavy-Duty Vehicles – Methodology for Estimating Charging Loads

LUMA decided to rely on the PR100 load forecast for these vehicle classes. Hence, much of the text below was adapted from the PR100 Study.

Detailed data on the use of medium and heavy-duty vehicles (MHDVs), similar to the vehicle-miles-traveled data contained in the continental United States-based Vehicle Inventory and Use Survey (U.S.

Census Bureau 2004), were unavailable for Puerto Rico at the time of the analysis. Therefore, PR100 decided to use proxy data to estimate the MHDV population:

- Data on goods imports, extracted from the U.S. Census Bureau's U.S. Trade with Puerto Rico and U.S. Possessions report, served as a proxy to estimate MHDV use in goods distribution. Import and export of goods was assumed to occur in two stages according to the following two assumptions: Goods are transported between San Juan and each municipality depot (long-haul) using Classes 7 and 8 HDVs, and goods are transported between the municipality depot and the destination (short haul) using Classes 2b, 3, 4, 5, and 6 MDVs. PR100 then estimated vehicle miles traveled and the geographic distribution of that travel by allocating a share of all imported goods to each vehicle class, in proportion to its total carrying capacity.

- Data on diesel fuel imports, particularly the amount of diesel fuel consumed daily in Puerto Rico[94] was used as a proxy to estimate vehicle use for all other transportation categories and vehicle body types shown in Figure 44. All diesel fuel used in Puerto Rico was assumed to be used for generation or transportation. A scaling factor was then developed to extrapolate energy use in the distribution of goods to all other MHDV uses.

Figure 44: Medium and Heavy-Duty Vehicle End-Uses[95]

class 2b - 3	class 4, 5, 6	class 7	class 8
emergency	small buses	street sweepers	semis
street sweepers	street sweepers	traffic service	cement mixers
traffic service	hub & spoke delivery vans	general daytime delivery	large cranes
utility service	traffic service	grocery chain delivery	dump truck
shuttles	cherrypickers / bucket trucks	garbage	refrigerated truck
hub & spoke delivery	fire truck	transit buses	tanker
non-consistent delivery	utility service	cranes	flatbed/long hauling
light hauling / exp. Shipping	moving vans	fire truck	
flatbed/hauling	furniture delivery	tanker	
	general daytime delivery	flatbed/long hauling	
	grocery chain delivery		
	flatbed/hauling		

The entire process and the assumptions used by PR100 to estimate the MHDEV charging load are described in four steps below.

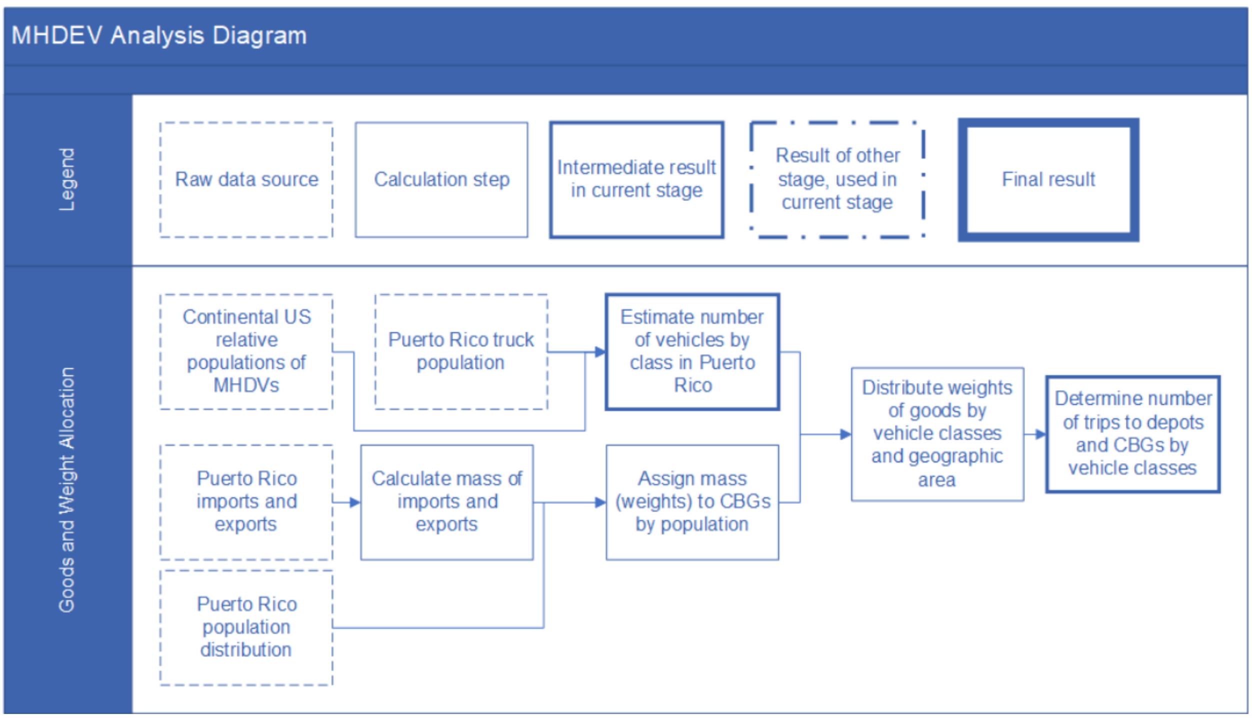
STEP 1. Goods and Weight Allocation: Figure 45 shows the process used to determine the number of trips, by vehicle class, required to transport goods between the Port of San Juan and census block groups (CBGs), via notional depots located at population centers at each municipality. The primary aim of

[94] U.S. Energy Information Administration. (n.d.). Puerto Rico Territory Energy Profile. https://www.eia.gov/state/print.php?sid=RQ
[95] Sandia National Laboratories presentation June 2, 2023

this stage was to determine the spatial distribution and mass of goods imported and exported from Puerto Rico. These results were then used to determine spatial demand for vehicle trips and charging demand across the Commonwealth. This stage comprised the following steps:

- Determine the mass of imported and exported goods.
- Assign imported and exported goods by weight according to population across Puerto Rico at the census block resolution.
- Allocate the weight of the goods to vehicles by class in proportion to maximum load capability
- Determine the number and origin-destination pairs for trips by vehicle class.

Figure 45: STEP 1. Analytical Approach Used to Allocate Imported Goods Among the Various Truck Classes

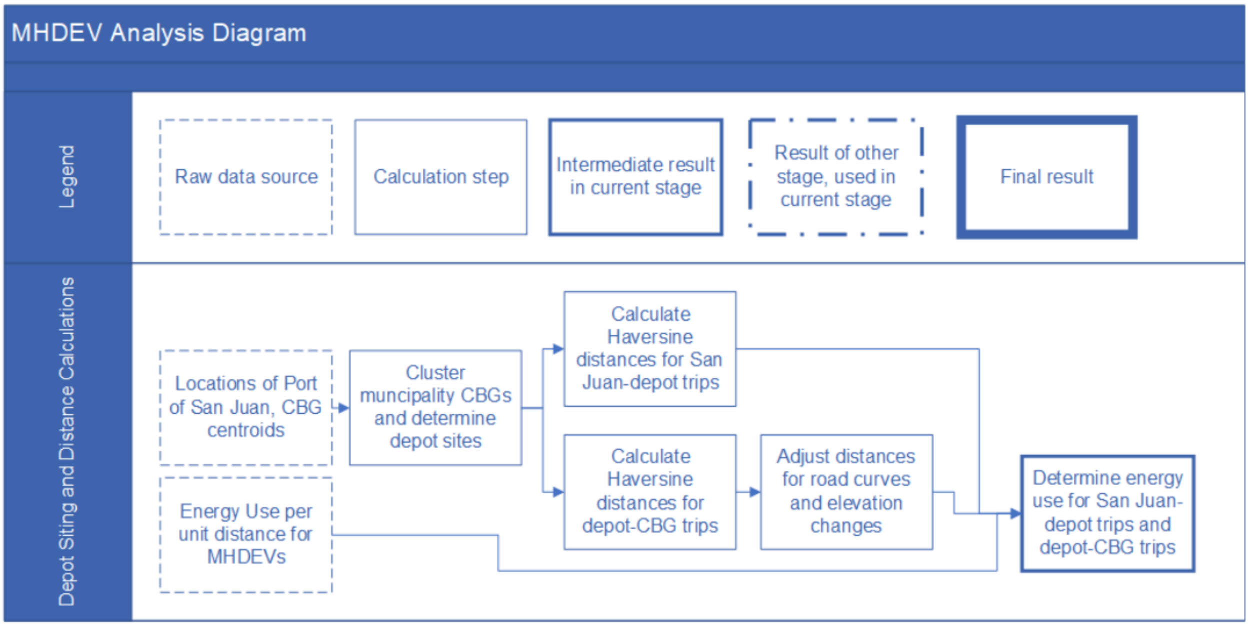


STEP 2. Depot Siting and Distance Calculations: This step (illustrated in Figure 46) was to compute the distances between the Port of San Juan and population centers at each municipality and between population centers and CBGs. This stage aimed to construct a transportation model to estimate distances that MHDEVs would use to inform charging rates as part of the load estimation. The model relied on hypothetical distribution depots placed at each municipality. This stage comprised the following steps:

- Site each municipality’s depot in a population cluster.
- Determine distances between the Port of San Juan and the depots.
- Determine distances between the depots and the centroids of the CBGs in the associated municipalities.

- Estimate vehicle energy use for San Juan–depot trips and depot-CBG trips.

Figure 46: STEP 2. Analytical Approach for Estimating Distance Travelled and Corresponding Energy Use Required to Distribute All Imported Goods



Conversion from estimated VMT to energy use requires an assumption on the energy efficiency of the trucks. MHDEV efficiencies in the PR100 estimate were adapted from the “Multi-State Transportation Electrification Impact Study” and other sources. The assumptions are summarized in Table 42.

Table 42: Assumed Electric Truck Efficiencies in the PR100 Study

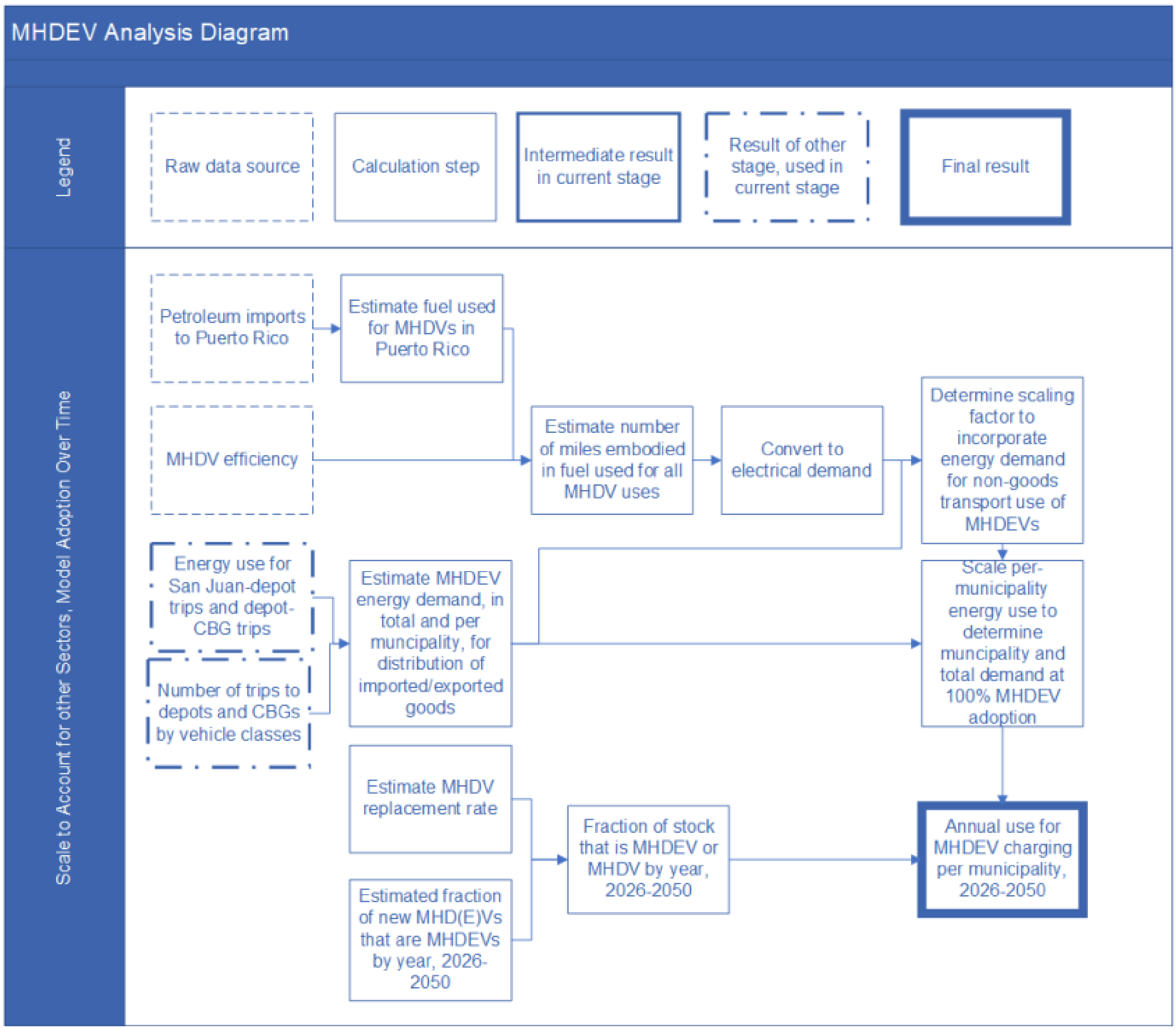
Route	Vehicle Class	Energy Efficiency (kWh/mile)	Route	Vehicle Class	Energy Efficiency (kWh/mile)
San Juan to the municipality depot:	7	1.7	Municipality depot to destination	2b	.5
	8	2.0		3, 4, 5	1.25
				6	1.5

STEP 3. Scaling to Account for Other Sectors and Modeling EV Adoption Over Time: Two modifications to the results were applied in sequence to obtain a more realistic approximation of the evolution of MHDEV charging demand for the period of interest. The output from the process shown in Figure 47 is used to scale the individual energy uses calculated previously for transporting imported and exported goods to account for MHDEV use cases in other sectors and their adoption over time. The scaling factor is derived from publicly available figures on petroleum imports and consumption for Puerto

Rico and estimates of miles driven[96] by MHDVs for all body types and end uses. Estimates were then scaled by the MHDEV adoption S-curve (see Figure 47). This stage comprised the following steps:

- Use the estimate of MHDV fuel use to scale results for other uses of MHDVs.
- Develop a stock-and-flow model of adoption over time.
- Additional details on these two steps are provided below.

Figure 47: STEP 3. Analytical Approach to Estimating Energy Consumption for All Medium and Heavy-Duty Vehicle Sectors, Electrified Fraction of the Market, and Corresponding Electricity Use



[96] Moog, E., Mammoli, A., Garrett, R. & Lave, M. (2023). PR100: Estimated Medium- and Heavy-Duty Electric Vehicle Adoption and Load Estimation in Puerto Rico through 2050. *Sandia National Laboratories* report SAND2023-14443, (December) (see Appendix C); https://www.osti.gov/biblio/2349515

Step 3A. Inputs and Assumptions for Estimating Energy Use of all Puerto Rico Diesel Trucks: Puerto Rico does not have oil production or refining, and all diesel for transportation is thus imported in its final form. According to EIA,[97] Puerto Rico imported 8,000 barrels/day of diesel fuel in 2021. Some of this fuel is used for generation, and the rest is used for trucking. The total energy needed for the MHDV fleet is then calculated as follows:

- Reduce total imports by the amount of diesel needed for the generation of fuel use
- The remainder, roughly 75% of this fuel, goes to MHDV transportation
- Subtract the energy used for goods delivery (see STEP 1); what remains is diesel use for other MHDV truck end-uses
- Other assumptions
  - Diesel engine efficiency is 25%.
  - The calorific value of diesel is 45.5 MJ/kg.
  - Density of diesel is 0.84 kg/liter.

Step 3B. Estimating Electric Vehicle Market Size and Corresponding Charging Load: PR100 estimated the growth of MHDEVs as follows:

- The total stock of MHDVs was assumed to remain the same for the entire period of interest. Only the composition—the percentage of electric versus non-electric vehicles—would change.
- In each year, 5% of vehicles (of all types) were assumed to be retired. This value was chosen because there were roughly 4 million Class 8 MHDVs on U.S. roads at the time of the study, and sales are steady at approximately 200,000 units per year. The assumption is that 5% of the existing fleet will be replaced each year, independently of the root cause for replacement.
- Retired vehicles would be replaced with MHDEVs or conventional MHDVs according to their share of the new MHDV market.
- The fraction of vehicles that were MHDEVs was assumed to be zero until 2026, and modeling began in 2026, at which point the initial fraction of MHDEVs was 0.02.
- The market share of EVs was assumed to grow at 4%/yr. At this rate, all new MHDVs in Puerto Rico, and therefore all replacements will be electric by 2050.

The resulting growth of the EV fraction in Puerto Rico is shown in Figure 48.

[97] U.S. Energy Information Administration. (n.d.). Puerto Rico Territory Energy Profile. https://www.eia.gov/state/print.php?sid=RQ

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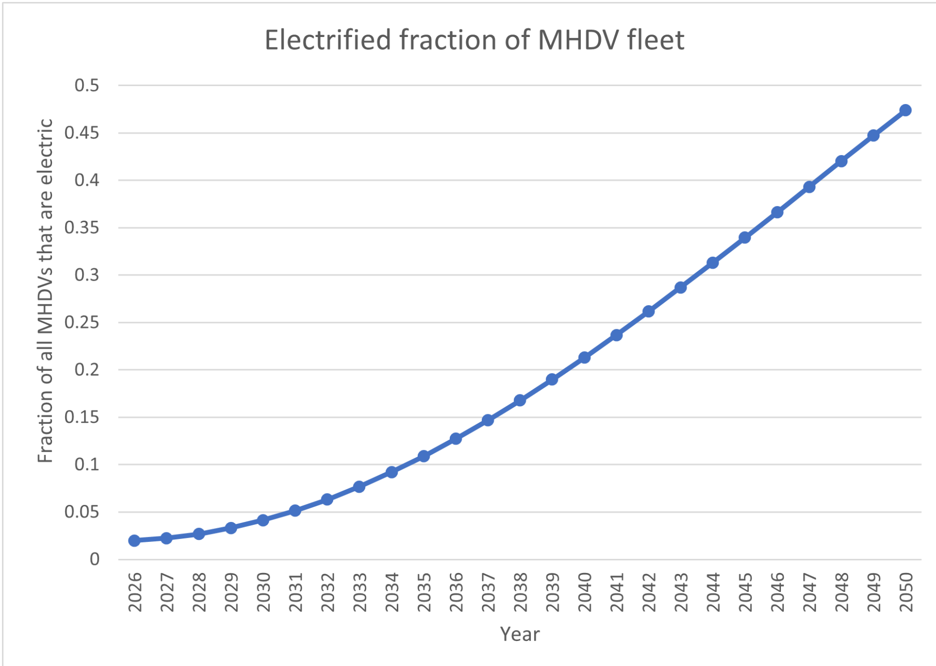
Figure 48: Fraction of Electrified Medium and Heavy-Duty Vehicles



The corresponding annual electricity use by municipalities and all of Puerto Rico is shown in Figure 49.

Figure 49: Annual Medium and Heavy-Duty Electric Vehicles Electricity Use by Municipality

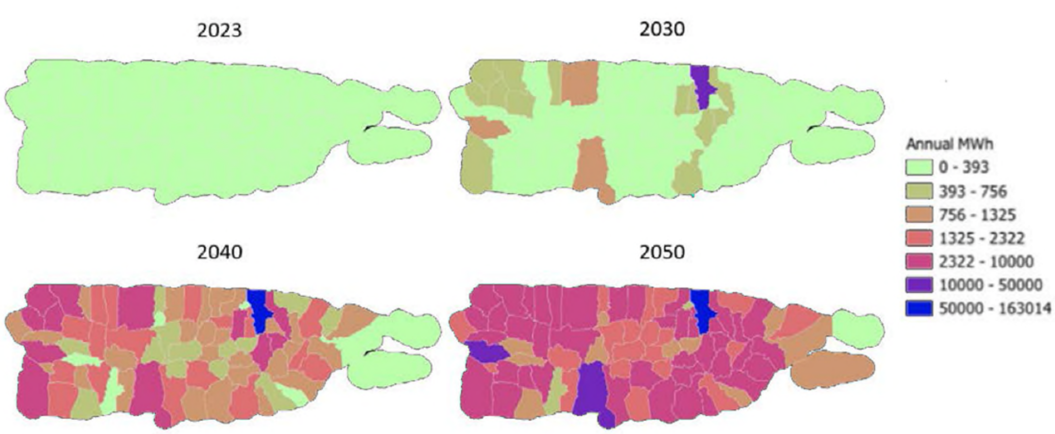
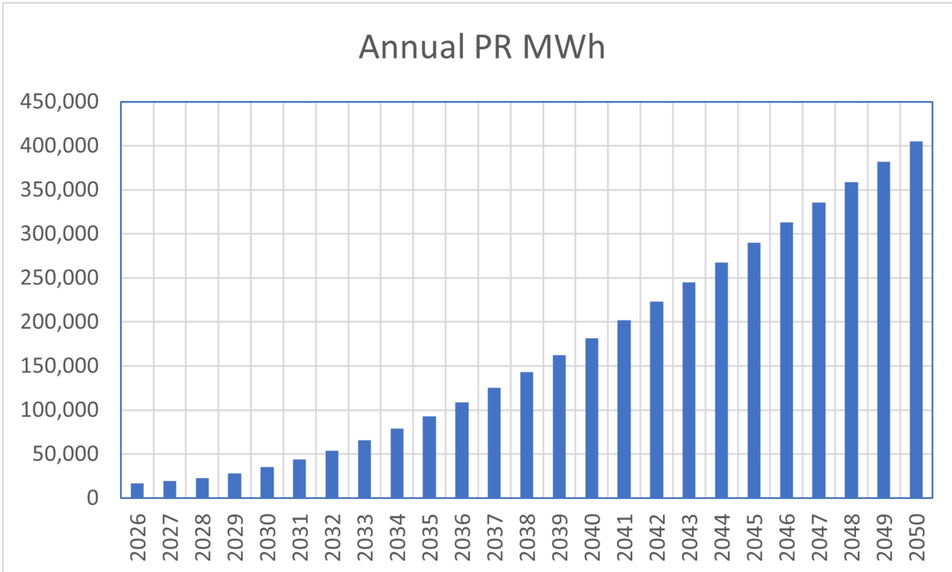


Figure 50: Total Annual Electricity Use by MHDEV in Puerto Rico

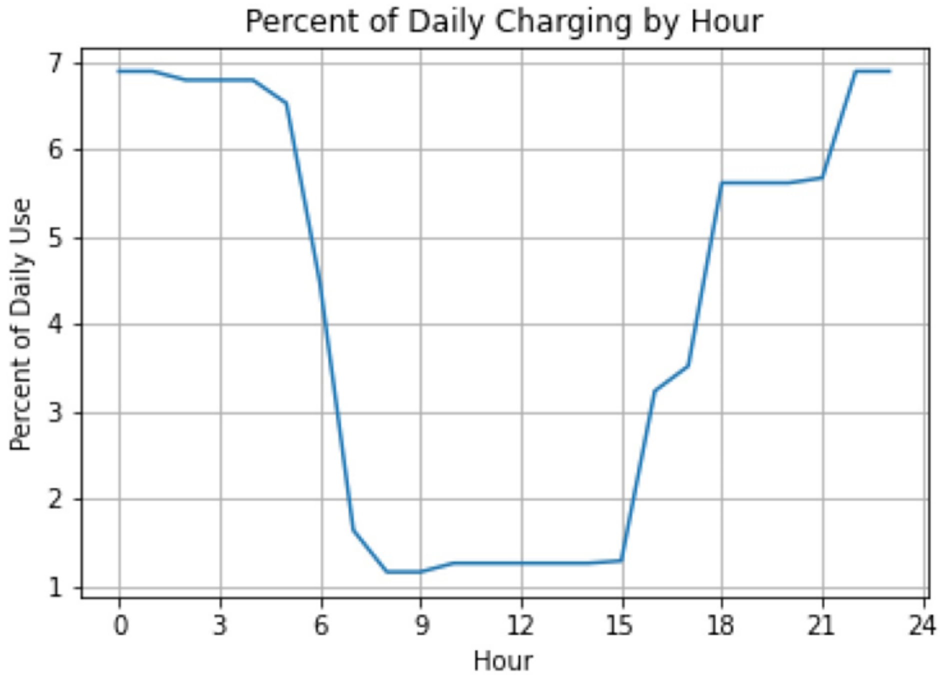


STEP 4. Charging Schedule Estimation: A charging schedule for each MHDV end use is estimated based on the mission, the vehicle miles traveled are estimated for each end use, and a weight factor based on the miles traveled is associated with the charging schedule for each end use, allowing the calculation of a combined charging schedule. This stage comprised the following steps:

- Estimate charging schedule by end use.
- Estimate the fraction of total energy use by end use and weight class.
- Develop hourly time-series estimation of the fraction of total daily energy use.

The corresponding load shape is shown in Figure 51. The load shape results from assuming that most charging would be done outside working hours. Without “smart” charging (charging load management) or incentives to shift load to times of ample supply, the MHDV load would exacerbate the system peak.

Figure 51: Hourly Distribution of Average Daily Charging Energy Needs of All Medium and Heavy-Duty Electric Vehicles



Observations

The expected Island-wide load due to MHDEV charging in 2050 of about 405,000 MWh is approximately 2.25% of the existing total load due to all other uses. Approximately half of this long-haul charging occurs in the San Juan municipality, making the load fraction due to MHDEV charging higher than in other municipalities.

Major uncertainties

- A central assumption underpinning the PR100 methodology was that using MHDVs in Puerto Rico would mirror the use of MHDVs in all continental United States economic sectors. This assumption enabled the incorporation of data to break down the percentage of MHDVs used in the continental United States by vehicle class and apply that percentage to Puerto Rico, which is not necessarily accurate.
- The U.S. Census Bureau Vehicle Inventory and Use Survey (VIUS) 2002 data set (U.S. Census Bureau 2004) was used for this analysis. VIUS 2022, the newest version of the survey since 2002, was unavailable at the time of this analysis and will contain information specific to Puerto Rico when it is released. This data source and others released over time could allow for improved charging schedule estimates.
- MHDEV technology will continue to evolve. In addition to relying solely on onboard batteries as the energy source, researchers are exploring various charging methods and roadway-based “drive-by” charging options.

Because of these and other uncertainties, the estimate of electricity use for charging a PR MHDEV fleet should, at best, be treated as indicative of the potential order of magnitude at full electrification of roadway truck traffic.

3.2.7 Combined Heat and Power

LUMA estimated the impact of existing and planned combined heat and power (CHP) projects in Puerto Rico. The FY2023 FOMB budget filing is LUMA's CHP forecast for the 2025 IRP. Based on the physical location of each CHP customer, this forecast was added to the appropriate TPAs.

Figure 52 presents a graphic illustration of the impact of CHP capacity on the energy system.

Figure 52: LUMA's Combined Heat and Power Capacity Impact (MW)

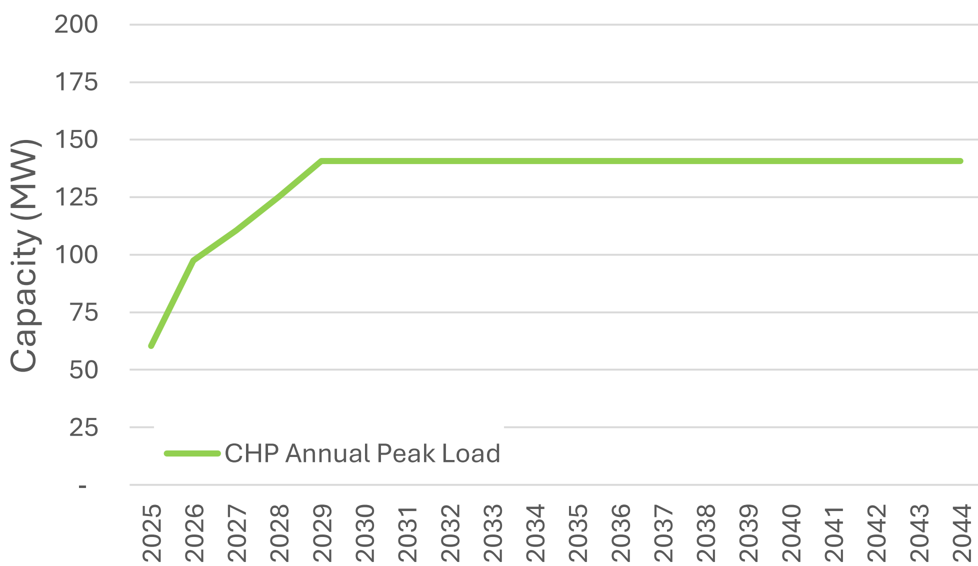
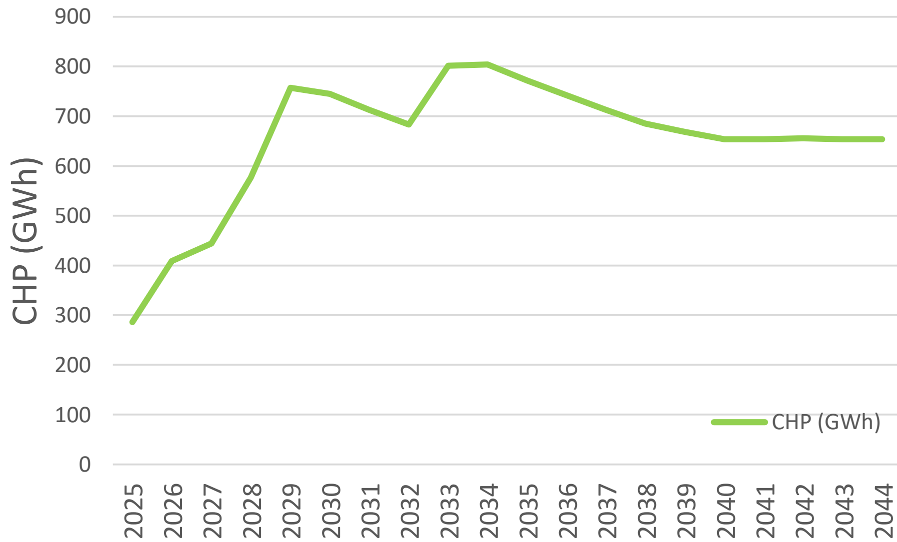


Figure 53 showcases the impact on energy generation (in GWh) associated with the CHP.

Figure 53: LUMA's Combined Heat and Power Energy Generation Impact (GWh)



3.3 Combined Load Forecast

Figure 54 showcases the peak load capacity forecast before applying the different load modifiers.

Figure 54: Peak Load Forecast Before Modifiers (MW)

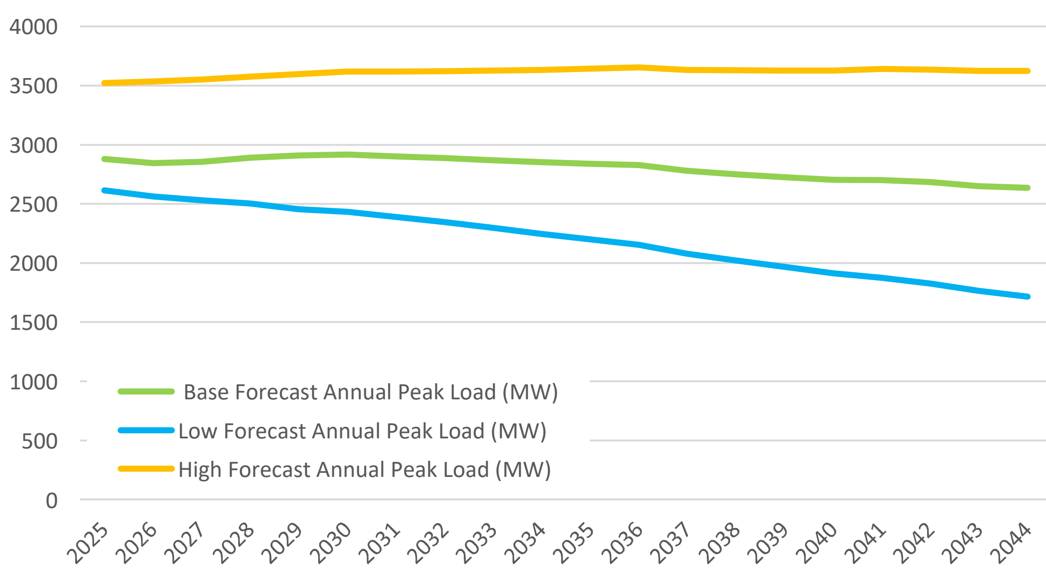


Figure 55 showcases a graph including the core peak load forecasts, adding the base load modifiers. As such, the impact of the load modifiers on the core load forecast can be appreciated if compared with the previous graph (Figure 54).

Figure 55: Peak Load Forecast with Load Modifiers (MW)

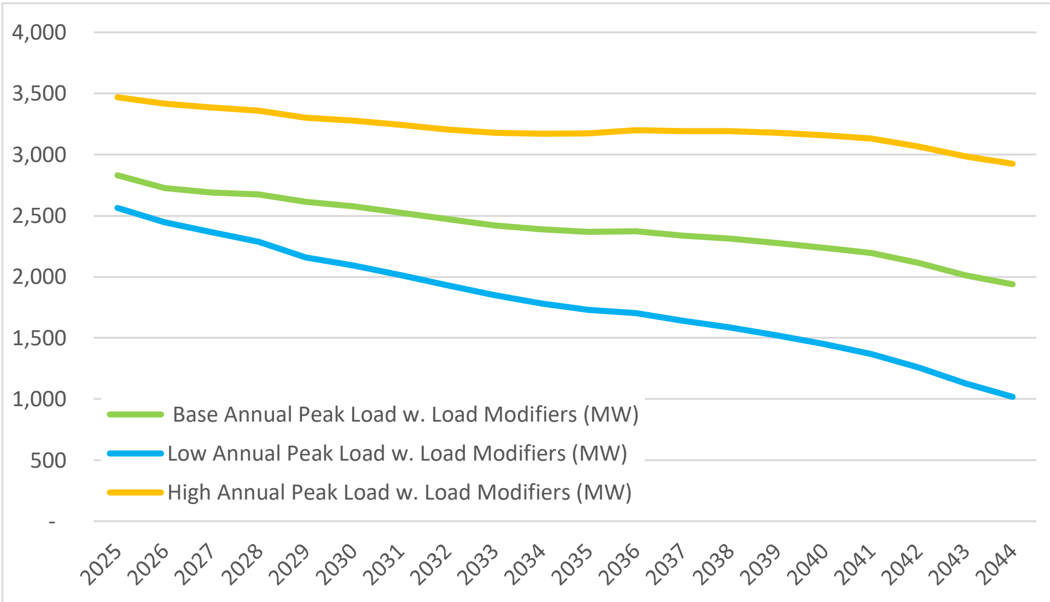


Figure 56 showcases the energy demand for each load forecast (base, low, and high) before applying the different load modifiers.

Figure 56: Core Load Forecast before Modifiers (GWh)

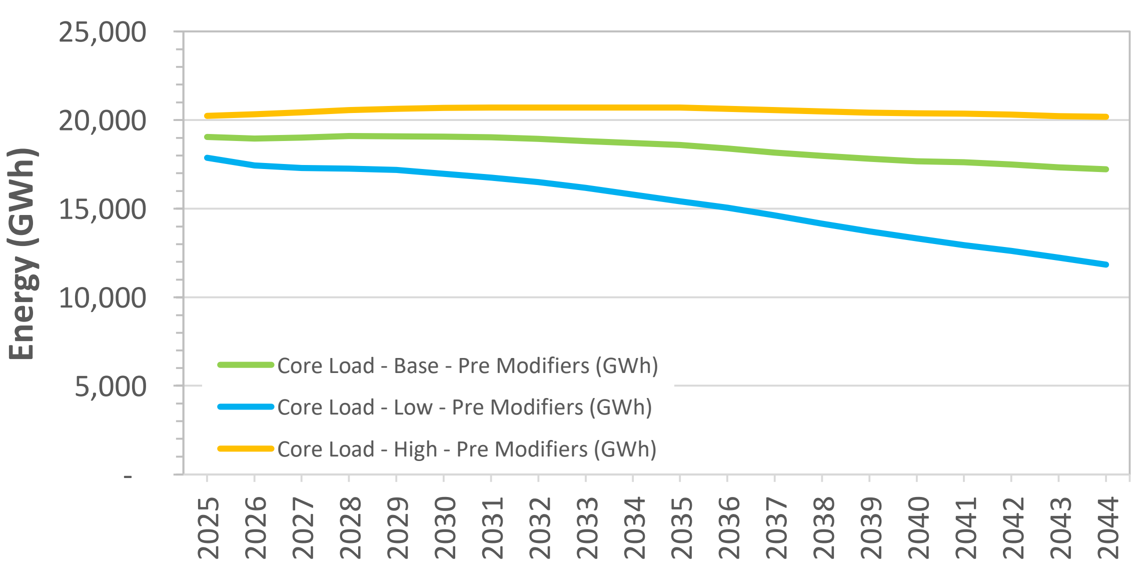
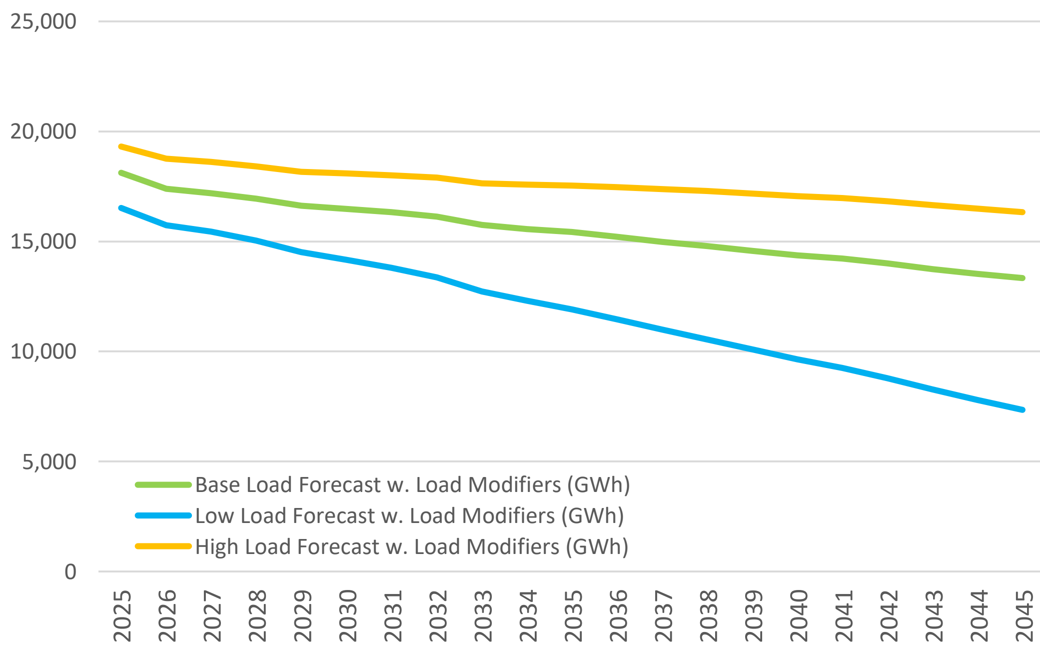


Figure 57 showcases a graph including the core load forecasts, adding the base load modifiers. As such, the impact of the load modifiers on the core load forecast can be appreciated if compared with the previous graph (Figure 56).

Figure 57: Core Load Forecast with Load Modifiers (GWh)



Section 4:

Existing Resources

4.0 Existing Supply-Side Resources

4.1 General Information on Supply-Side Resources

This section summarizes the supply-side resources that serve LUMA customers in Puerto Rico. PREPA owns most of the existing supply resources. However, Genera PR has been managing, operating, and maintaining all PREPA's fossil-fueled units since July 2023. The hydroelectric units are the only power supply resources PREPA still operates. Besides PREPA-owned resources, Puerto Rico has some independent power producers (IPPs), which include two large fossil-fueled power plants and eleven renewable projects.

Table 43 provides general descriptions of the PREPA-owned resources, including the resource type, fuel type, municipality where the unit is located, and commercial operation date (COD) for each unit. It does not consider units that are currently out of service and no longer operable, such as San Juan 8, San Juan 10, Palo Seco 1, Palo Seco 2, Cambalache 1, various gas turbines (GTs) (F5)[98], and some hydro units. Another critical aspect to consider is that the information regarding GT (F5) units is based on their availability in 2023. The current number of GTs available could vary. Bunker fuel is equivalent to heavy fuel oil.

Table 43: General Data for Puerto Rico Electric Power Authority-Owned Resources

Generator	Resource Type	Fuel Type	Municipality	COD
Aguirre 1	Thermal	Bunker	Salinas	1971
Aguirre 2	Thermal	Bunker	Salinas	1971
Costa Sur 5	Thermal	Natural gas and bunker	Peñuelas	1972
Costa Sur 6	Thermal	Natural gas and bunker	Peñuelas	1973
Palo Seco 3	Thermal	Bunker	Toa Baja	1968
Palo Seco 4	Thermal	Bunker	Toa Baja	1968
San Juan 5 CC	Thermal	Natural gas and diesel	San Juan	2008
San Juan 6 CC	Thermal	Natural gas and diesel	San Juan	2008
San Juan 7	Thermal	Bunker	San Juan	1965
San Juan 9	Thermal	Bunker	San Juan	1968
Aguirre 1 CC	Thermal	Diesel	Salinas	1977
Aguirre 2 CC	Thermal	Diesel	Salinas	1977
Cambalache 2	Thermal	Diesel	Arecibo	1998
Cambalache 3	Thermal	Diesel	Arecibo	1998
Mayagüez 1	Thermal	Diesel	Mayagüez	2009
Mayagüez 2	Thermal	Diesel	Mayagüez	2009
Mayagüez 3	Thermal	Diesel	Mayagüez	2009
Mayagüez 4	Thermal	Diesel	Mayagüez	2009

[98] GT F5 are peaking units installed in the 1970s. F5 stands for "Frame 5," which is the unit's model.

Generator	Resource Type	Fuel Type	Municipality	COD
GT01 - Palo Seco	Thermal	Diesel	Toa Baja	1972
GT02 - Palo Seco	Thermal	Diesel	Toa Baja	1972
GT11 - Yabucoa	Thermal	Diesel	Yabucoa	1972
GT19 - Jobos	Thermal	Diesel	Guayama	1972
GT20 - Jobos	Thermal	Diesel	Guayama	1972
GT21 - Daguao	Thermal	Diesel	Ceiba	1972
GT22 - Daguao	Thermal	Diesel	Ceiba	1972
Palo Seco Mobile Pack 1	Thermal	Diesel	Toa Baja	2021
Palo Seco Mobile Pack 2	Thermal	Diesel	Toa Baja	2021
Palo Seco Mobile Pack 3	Thermal	Diesel	Toa Baja	2021
Palo Seco TM[99] Gen 4-1	Thermal	Natural gas and diesel	Toa Baja	2023
Palo Seco TM Gen 4-2	Thermal	Natural gas and diesel	Toa Baja	2023
Palo Seco TM Gen 6-1	Thermal	Natural gas and diesel	Toa Baja	2023
Palo Seco TM Gen 6-2	Thermal	Natural gas and diesel	Toa Baja	2023
San Juan TM Gen 6-1	Thermal	Natural gas and diesel	San Juan	2023
San Juan TM Gen 6-2	Thermal	Natural gas and diesel	San Juan	2023
San Juan TM Gen 6-3	Thermal	Natural gas and diesel	San Juan	2023
San Juan TM Gen 6-4	Thermal	Natural gas and diesel	San Juan	2023
San Juan TM Gen 6-5	Thermal	Natural gas and diesel	San Juan	2023
San Juan TM Gen 6-6	Thermal	Natural gas and diesel	San Juan	2023
San Juan TM Gen 6-7	Thermal	Natural gas and diesel	San Juan	2023
San Juan TM Gen 6-8	Thermal	Natural gas and diesel	San Juan	2023
San Juan TM Gen 6-9	Thermal	Natural gas and diesel	San Juan	2023
San Juan TM Gen 6-10	Thermal	Natural gas and diesel	San Juan	2023
Dos Bocas 2	Renewable	Hydro	Arecibo	1942
Dos Bocas 3	Renewable	Hydro	Arecibo	1942
Garzas 1-1	Renewable	Hydro	Adjuntas	1941
Garzas 1-2	Renewable	Hydro	Adjuntas	1941
Toro Negro 1-1	Renewable	Hydro	Villalba	1929
Toro Negro 1-2	Renewable	Hydro	Villalba	1936
Toro Negro 1-3	Renewable	Hydro	Villalba	1936
Yauco 2-1	Renewable	Hydro	Yauco	1954

[99] TM stands for trailer-mounted units, typically portable power generation equipment in the electric industry.

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Generator	Resource Type	Fuel Type	Municipality	COD
Yauco 2-2	Renewable	Hydro	Yauco	1954

Table 44 shows general information for the operating IPPs with supply contracts in place with PREPA.

Table 44: General Data for Independent Power Producer Resources

Generator	Resource Type	Fuel Type	Owner/ Developer	Municipality	COD	End of Contract
[redacted]						

[redacted]

4.2 Technical Information on Supply-Side Resources

Table 45 summarizes technical information about PREPA's supply resources. The available capacity of each unit may vary from year to year, depending on its condition and status. Palo Seco mobile packs one to three have data available since the year after their start of commercial operation (2022). Palo Seco and San Juan TM generators have data since their start of commercial operation (2023).

Table 45: Technical Data of PREPA-Owned Resources

Generator	Nameplate Capacity (MW)	Available Capacity (MW)	Heat Rate (MMBTU/MWh)	Forced Outage Rate (%)
[redacted]				

Generator	Nameplate Capacity (MW)	Available Capacity (MW)	Heat Rate (MMBTU/MWh)	Forced Outage Rate (%)
[redacted]				

Generator	Nameplate Capacity (MW)	Available Capacity (MW)	Heat Rate (MMBTU/MWh)	Forced Outage Rate (%)
[redacted]				

N/Av = Not available
N/A = Not applicable

Table 46 shows the same technical information for the IPPs that supply LUMA customers. Note that renewables do not have heat rate values since they do not consume fuel. Punta Lima was in pre-operation during the last quarter of 2023.

Table 46: Technical Data of Independent Power Producer Resources

Generator	Nameplate Capacity (MW)	Available Capacity (MW) (as of 2025)	Heat Rate (MMBTU/MWh)	Forced Outage Rate (%)
[redacted]				

N/Av = Not available
N/A = Not applicable

4.3 Cost Information for Supply-Side Resources

Table 47 summarizes the cost values of the PREPA-owned supply-side resources, including the fuel type, fuel prices (per type), and fixed and variable operation and maintenance (FO&M and VO&M) costs. Fuel prices are volatile and change monthly, as is the production cost, which is relative to prices. The fuel and production prices shown in Table 47 depict the corresponding price for May 2025. Note that, for May 2025, Aguirre production cost is $0 because the powerplant was fully out of service.

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Table 47: Cost Information on PREPA-Owned Resources

Generator	Fuel Type	FO&M ($/kW-yr)	VO&M ($/MWh)	Fuel prices ($/MMBtu) (as of May 2025
[redacted]				

Generator	Fuel Type	FO&M ($/kW-yr)	VO&M ($/MWh)	Fuel prices ($/MMBtu) (as of May 2025
[redacted]				

N/A = Not applicable N/Av = Not available

Table 48 and Table 49 summarize the cost values of the IPP.

Table 48: Cost Information of Independent Power Producer Resources

Generator	Fuel/Source Type	FOM ($/kW-yr)	VOM ($/MWh)	Fuel prices ($/MMBtu) (as established by contract)	Production Cost ($/MWh) (as established by contract for 2025)	Price Escalator (%)	End of Contract
[redacted]							

Generator	Fuel/Source Type	FOM ($/kW-yr)	VOM ($/MWh)	Fuel prices ($/MMBtu) (as established by contract)	Production Cost ($/MWh) (as established by contract for 2025)	Price Escalator (%)	End of Contract
[redacted]							

N/A = Not applicable

Notes:

- All solar IPPs have a yearly fixed price escalator until the end of the contract year.
- Wind IPPs (Pattern and Punta Lima) have a non-fixed price escalator. Refer to Table 7 for prices applicable throughout the term of each contract.
- The EcoEléctrica fuel price shown is the May 2025 fuel price. The methodology for calculating fuel prices is the same as that used for Genera's fleet. AES has a fixed, established fuel price by contract, as renewables have their established production cost by contract.

Table 49: Pattern and Punta Lima Production Costs Through Their Respective Contracts

Year	Pattern Production Cost ($/MWh)	Punta Lima Production Cost ($/MWh)
[redacted]		

4.4 General Information on Demand-Side Resources

LUMA's existing and planned demand-side resources (e.g., energy efficiency and demand response programs) are discussed in detail in sections 3 and 6 of this report. LUMA is also promoting various rate designs intended to reduce peak demand, including two discussed below.

- **Electric Vehicle Time-of-Use Pricing**: LUMA is piloting an Electric Vehicle Time of Use Rate ("EV-TOU") through FY2026. This pricing pilot charges different rates for electricity based on the time of day to encourage customers who own electric vehicles to charge their vehicles during off-peak hours when the demand on the system is less, and the rate is lower.
- **Industrial Time-of-Use Pricing**: LUMA promotes its Industrial Time-of-Use ("ITOU") rate to industrial customers to reduce demand during peak periods. The ITOU provides lower rates during off-peak hours and higher rates during peak hours, creating incentives for customers to shift demand to off-peak hours.

Section 5: Resource Needs Assessment

5.0 Resources Needs Assessment

The Resource Needs Assessment (RNA) is prepared to comply with the requirements of Regulation 9021. The objective is to evaluate the current and future needs of the Puerto Rico electric system over a 20-year planning horizon (2025-2044), ensuring energy services for Puerto Rico are fully aligned with the regulatory framework of Regulation 9021, the Puerto Rico Energy Public Policy Act (Act 17-2019, as amended) and the Puerto Rico Energy Transformation Relief Act (Act 57-2014, as amended).

Puerto Rico continues to face critical challenges due to its heavy reliance on imported fuels, deteriorated infrastructure, and vulnerability to natural disasters. In 2019, the Puerto Rico Energy Public Policy Act (Act 17-2019) was enacted to resolve the precarious situation of the electric power service, which described the electrical power service in Puerto Rico as "[*i*]*nefficient, unreliable, and provided at an unreasonable cost to residential, commercial, and industrial customers despite the existence of a vertically integrated monopolistic structure. This is mainly due to a lack of infrastructure maintenance, the inadequate distribution of generation vis-à-vis demand, the absence of the necessary modernization of the electrical system to adjust it to new technologies, energy theft, and the reduction of the Electric Power Authority's personnel. Likewise, the electrical system of the Island is highly polluting as a result of poor energy diversification, the hindering of the integration of distributed generation and renewable energy sources, and high fossil fuel dependency."*[100] In this law, the Legislature sought to "*set parameters that shall guide Puerto Rico towards a future where the energy system is resilient, reliable, and robust, and allows for consumers to be active agents, the modernization of the transmission and distribution network, the transition from fossil fuels to renewable energy sources, the integration of distributed generation , and state of the art technology that benefits consumers and results in rates below twenty cents ($0.20) per kilowatt-hour*".[101] To attain these objectives Act 17-2019" provides the means to *establish an effective programming that allows for the setting of clear parameters and goals for energy efficiency, the Renewable Portfolio Standard, the interconnection of distributed generators and microgrids, wheeling, and the management of electricity demand*."[102]

Puerto Rico's current generation landscape is fossil fuel dependent. Over 90% of Puerto Rico's electricity is generated from fossil fuels, including coal, diesel, heavy fuel oil, and natural gas. Puerto Rico's dependance on fossil fuels is concerning and negatively affects the people of Puerto Rico and its business sector since it makes the Island's electric system vulnerable, expensive and environmentally damaging. Puerto Rico faces high energy costs and is at the mercy of global fuel price fluctuation because it must import all fossil fuels. In addition, the current situation is worsened by the deteriorating condition of the existing generation fleet. Many generation units are over 40 years old, in poor condition, inefficient, and frequently break down, which leads to blackouts and costly repairs. The Island remains trapped in a cycle of high costs and unreliable service. Act 17-2019 and the Puerto Rico Energy Transformation Relief Act (Act 57-2014) require the completion of an IRP defining it as a "*plan that considers all reasonable resources to satisfy the demand for electric power services during a specific period of time, including those related to energy supply, whether existing, traditional, and/or new resources, and those related to energy demand, such as energy conservation and efficiency, demand response, and distributed generation* […]"[103] These laws also direct that the IRP be revised and updated every three years reflecting the changes in the energy market conditions, changes in technology,

[100] See : https://bvirtualogp.pr.gov/ogp/Bvirtual/leyesreferencia/PDF/2-ingles/17-2019.pdf
[101] See id.
[102] Id.
[103] Act 17-2019, Section 1.2(p); Act 57-2014, as amended, Section 1.3(ll).

environmental regulations, fuel prices, capital costs, and other factors.[104] Pursuant to Section 6.23 of Act 57-2014, as amended, and Section 6C of Act 83 of May 2, 1941, as amended, the Energy Bureau adopted Regulation 9021 to govern the IRP process and every three years "to ensure that the IRP serves as an adequate and useful tool to guarantee the orderly and integrated development of Puerto Rico's electric power system, and to improve the system's reliability, resiliency, efficiency, and transparency, as well as the provision of electric power services at a reasonable price."[105] The 2025 IRP provides a comprehensive assessment of Puerto Rico's current generation resources, projected energy demand, renewable energy potential, infrastructure needs, and policy framework to guide the transition towards a resilient and sustainable future.

5.1 Loss of Load Expectation and Planning Reserve Margin Assessment

Regulation 9021 indicates that LUMA should consider assessing its Planning Reserve Margin ("PRM") when preparing an RNA. PRM is the amount of generating capacity a power system must have above its expected peak demand to ensure it can meet load and prevent energy shortages.[106]

LUMA considered starting with a PRM to determine its RNA but determined that the PRM methodology had several weaknesses when analyzing Puerto Rico's electric system and its characteristics. Specifically, the PRM focuses solely on resource adequacy during peak demand hours, rather than throughout the day, and does not consider the age or condition of existing resources. The lack of consideration for the age and condition of existing resources is especially problematic in Puerto Rico, where many units experience significant and prolonged outages. To rectify these problems and identify standards that would more effectively ensure reliability on an hourly basis rather than a peak day basis, LUMA determined that the use of probabilistic methods of assessing resource adequacy, such as Loss of Load Expectation ("LOLE") and Expected Unserved Energy ("EUE"), would be more effective.

LOLE is the projected loss of load over a given period in the future. A common LOLE reliability goal that is frequently referenced in industry literature is a LOLE of 1 day in 10 years, which allows for only a single loss of load event of no more than 24 hours within a 10-year period. LUMA, other utilities and independent system operators rely on LOLE as a more comprehensive indicator of projected reliability and system adequacy than PRM.

It has been recognized that the implementation and tracking of a target that allows for only a single loss of load event over a 10-year period is problematic. An annual LOLE target is easier to apply in planning compared to a target that requires data over a 10-year period. Utilities and regional independent system operators have translated the 10-year goal to an annual goal. The annual translation takes the one day from the 10-year goal and divides the one-day (or 24 hours) goal by 10-years, yielding a comparable and more practical translation of the goal to 0.1 day/year (i.e., identical to 2.4 hours/year). This annual target LOLE of no more 2.4 hours/year is the value that is commonly used by utilities and independent system

[104] See Act 17-2019, Section 1.9(2); Act 57-2014, as amended, Section 6.23.
[105] Regulation 9021
[106] The NERC Reliability Assessment Subcommittee (RAS) defines Reserve Margin (%) = (Resource Capacity – net internal demand)/net internal demand X 100.

operators[107,108,109] as a target in resource adequacy for planning purposes. The LOLE value of 2.4 hours/year allows for only a single loss of load event per year that is less than or equal to 2.4 hours in duration.

PLEXOS does not output LOLE for its ST model (i.e., the PLEXOS detail production model) but it does have the ability to report EUE, which is the number of loss of load events and the durations of those events (in hours) for each year. The LOLE of 2.4 hours/year is equal to EUE of 2.4 hours/year and one loss of load event per year.

LUMA's most recent Resource Adequacy Report[110] projects 154 hours/year of EUE (referenced as the equivalent Loss of Load Hours in the Resource Adequacy Report), for the year 2025. While it will require substantial improvement, especially with the existing age and reliability of Puerto Rico's existing generation fleet, LUMA believes targeting a goal of EUE of 2.4 hours/year in Puerto Rico is a reasonable planning target that should be achievable within the planning horizon of the 2025 IRP. After reviewing preliminary modeling runs for the 2025 IRP, LUMA developed its recommended annual targets for EUE to move Puerto Rico toward system reliability that is commensurate with other utilities. Table 50 shows the recommended EUE annual target values that will begin in 2030 and will reach the industry standard EUE of 2.4 hrs./year in 2038.

Table 50: Target LOLE Improvement for 2025 IRP

Year	Expected Unserved Energy (hrs)
2030	60.6
2031	40.4
2032	26.9
2033	18.0
2034	12.0
2035	8.0
2036	5.3
2037	3.5
2038 to 2044	2.4

The annual EUE targets were defined to provide a progressive improvement in LOLE for each year. LUMA assumed that 2030 was the earliest that new capacity could be added in the 2025 IRP that was not included in the fixed decisions for which the procurement was underway. Given the large quantity of fixed decision resource additions that occur prior to 2030, in LUMA's judgement, it was estimated that an additional eight years after 2030 should provide sufficient time to implement the resource changes that

[107] See EPRI Resource Adequacy Practices and Standards for a list of LOLE targets used in US system planning, https://msites.epri.com/resource-adequacy/metrics/practices-and-standards

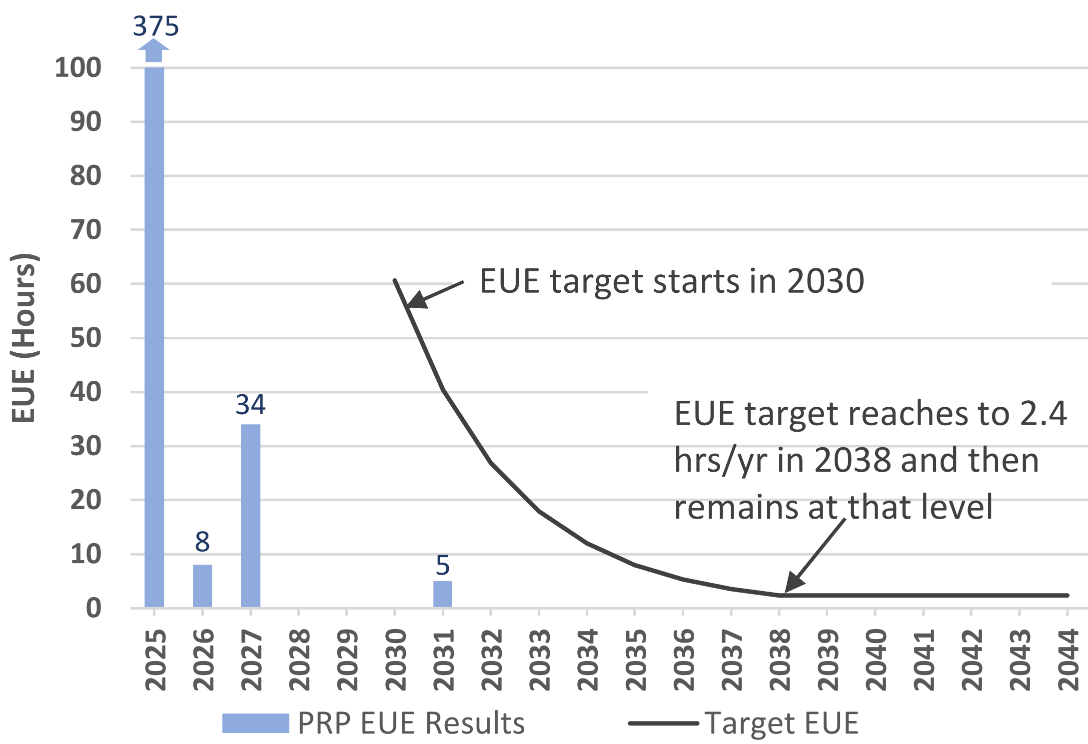
[108] See EPRI Metrics Explainers, https://msites.epri.com/resource-adequacy/metrics/metrics-explainers#4257225834-1165899977

[109] It should be noted that a LOLE of year 0.1 days/year or 2.4 hours/year, is not equivalent to the often referenced LOLE of 1 day in 10 years. A LOLE of 1 day in 10 years allows for only a single loss of load event of no more than 1 day (i.e., 24 hours) in a 10-year period. While a LOLE of 0.1 days/year allows for a single loss of load event each year. If a utility had a single loss of load event each year it would achieve a LOLE target of 0.1 day/year but would also result in 10 events over a ten-year period and a LOLE result of 10-days in 10-years, which is ten times the result allowed in a 1 day in 10-year LOLE target. In addition, an annual LOLE target is easier to apply in planning than a target that requires forecasting performance over a 10-year period.

[110] Puerto Rico Electricity System Resource Adequacy, Case No. NEPR-MI-2022-00002 Report filed on October 31, 2024, page 9 at energia.pr.gov/wp-content/uploads/sites/7/2024/10/20241031-MI20220002-Resource_Adequacy-1.pdf

would significantly improve the EUE performance of the system. This time frame was also judged by LUMA to be sufficient for Genera to implement any planned improvements to existing generation units that would improve their reliability to sufficiently improve the forced outage rates and delay or eliminate future unit additions or retirements. Figure 58 illustrates the annual progressive improvement in EUE that LUMA has included in its recommended LOLE targets and the actual results from the PRP. The 2025 EUE estimate in Figure 58 is based on results from the resource modeling software which estimated a higher value in 2025 than LUMA's most recent Resource Adequacy study (375 hrs in the IRP versus 154 hours in the Resource Adequacy Study). However, the difference can be largely explained by the assumption that Aguirre 1 ST was assumed to be operating, and Aguirre 2 ST was assumed out of service in in the Resource Adequacy Study while both units were assumed to be out of service for the entirety of the IRP study.

Figure 58: Target Expected Unserved Energy



As noted above, LUMA chose to use EUE hours and the number of loss of load events per year as the indicators of reliability performance for this IRP. However, since Regulation 9021 discusses PRM, LUMA also addresses that methodology further here, The PRM has historically been a key metric to ensure sufficient resources are available to meet load at the time of the electric system's peak load and the PRM that any utility maintains will vary based on many factors, among them:

- Whether the utility is interconnected to a grid of neighboring utilities that also maintain their reserve margins – utilities that are not connected to a grid will generally have a higher PRM.
- Age and condition of the available energy resources – utilities with older or less reliable energy resources will tend to have higher PRM.

- Historical reliability of the energy resources available – utilities have different methods for addressing the forced outage rates of their generation fleet, however, generally higher forced outage rates result in higher PRM.
- Planned maintenance requirements and schedules – utilities plan maintenance work years in advance. Even though utilities will plan maintenance schedules to avoid working on large generators near the time of the expected system peak load, they also may maintain a higher PRM during years where there is an unusually high quantity of generation with planned maintenance.

Considering the lack of interconnections, age and condition of existing generation, and historically very poor reliability of the existing generation fleet, each of these factors would serve to increase the prudent PRM for Puerto Rico beyond that of a typical utility with typical generation age and reliability, and LUMA did not plan the current IRP using that methodology as the base. However, as shown below, LUMA does provide information in this report regarding its expected PRM.

5.2 Load and Resource Balance

Table 51 lists the load and resource balance, including the total annual capacity of all energy resources, the capacity of dispatchable energy resources available to serve the system peak load, the forecasted system peak load, and the PRM. Table 52 lists the projected annual energy resource capacity by unit.

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Table 51: Total Annual Energy Resources, System Peak Load and PRM

Units	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Total Capacity (MW)	5,164	7,721	8,284	8,864	8,114	7,854	8,348	8,203	8,170	8,231	7,987	7,719	8,198	7,884	7,595	7,729	7,884	8,064	8,257	8,416
Total Dispatchable Capacity for Peak Load (MW)[111]	4,431	6,128	6,596	7,079	6,284	5,974	6,398	6,184	6,106	6,110	5,817	5,525	5,988	5,583	5,179	5,184	5,187	5,191	5,195	5,199
System Peak Load (MW)	2,875	2,784	2,741	2,693	2,684	2,654	2,632	2,608	2,599	2,596	2,593	2,553	2,532	2,512	2,491	2,489	2,472	2,443	2,430	2,419
Planning Reserve Margin (%)	54%	120%	141%	163%	134%	125%	143%	137%	135%	135%	124%	116%	137%	122%	108%	108%	110%	112%	114%	115%

Table 52: Annual Energy Resource Forecasted Dependable Capacity by Unit for PRP (MW)

Units	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044

[redacted]

[111] Total Dispatchable Capacity for Peak Load includes firm capacity that is available for dispatch at the evening peak load, which excludes generation from solar, wind, landfill gas, hydroelectric and CHP.

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Units	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044

[redacted]

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Units	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
[redacted]																				

2025 Integrated Resource Plan Report

Units	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
[redacted]																				

2025 Integrated Resource Plan Report

Units	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
[redacted]																				

2025 Integrated Resource Plan Report

Units	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044

[redacted]

Units	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
[redacted]																				

2025 Integrated Resource Plan Report

Units	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
[redacted]																				

Units	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
[redacted]																				

Section 6:

New Resource Options

6.0 New Energy Resources

This section identifies new resource options evaluated in the 2025 IRP, including distributed generation, demand-side resources, and storage technologies, based on scenario modeling and stakeholder inputs. The 2025 IRP modeling team assessed these resources across different scenarios and selected a preliminary preferred plan based on cost, flexibility, and policy alignment.

To develop the 2025 IRP, LUMA conducted a thorough assessment of diverse supply-side resource options, which included both renewable and non-renewable energy sources. As part of this assessment, LUMA identified which options were and were not feasible for future development given the current state of the energy sector in Puerto Rico.

6.1 Fixed Energy Resource Decisions (Fixed Decisions)

LUMA incorporated a list of fixed energy resource addition and retirement decisions into the 2025 IRP, which includes projects that are either already approved, under construction, or at an advanced stage of development with a high likelihood of being completed or retired. These fixed decisions are treated as predetermined commitments within the modeling process and are included across all scenarios to reflect an accurate representation of the system's expected baseline. By accounting for these fixed decisions, LUMA ensures that the 2025 IRP is consistent with regulatory approvals and real-world developments, providing a foundation for evaluating future resource options. The following subsections describe each of the fixed decision categories and their corresponding projects.

6.1.1 Non-Tranche Projects

Energy resource additions categorized in this section are associated with new renewable and thermal energy resources that were contracted outside of the Tranche solicitations[112]. Table 53 provides a list of the projects and their characteristics that fall into this category.

Table 53: Non-tranche Projects

Project Name	Resource Type	Fuel Type	Location	Capacity	COD	Heat Rate (BTUs/kWh)	Overnight Capital Cost	Fixed O&M Costs	Variable O&M Costs
[redacted]									

[112]. Tranches as a series of competitive procurements for utility scale renewable energy and battery energy storage services conducted by the Puerto Rico Electric Power Authority ("PREPA") as required under the Final Resolution and Order on the Puerto Rico Electric Power Authority's Integrated Resource Plan, In re: Review of the Integrated Resource Plan of the Puerto Rico Electric Power Authority, Case No. CEPR-AP-2018-0001, of August 24, 2020. The Tranches are being overseen by the Energy Bureau in Case No. NEPR-MI-2020, 0012, In re: Implementation of the Puerto Rico Electric Power Authority Integrated Resource Plan and Modified Action Plan.

Project Name	Resource Type	Fuel Type	Location	Capacity	COD	Heat Rate (BTUs/kWh)	Overnight Capital Cost	Fixed O&M Costs	Variable O&M Costs
[redacted]									

6.1.2 Tranche Projects

Tranche projects include the selected and contracted projects that resulted from series of requests for proposals (RFPs) for the development of renewable energy and energy storage. LUMA considered Tranche 1, 2, and 4 projects for the 2025 IRP, showcased in Table 54, Table 55, and Table 56, respectively. None of the Tranche 3 solicitation projects were included in the 2025 IRP since this solicitation was canceled.

Table 54: Tranche 1 Projects

Project Name	Resource Type	Location	Capacity	COD	Owner	PPOA Price ($/kWh)	Monthly Capacity Payment Price ($/MW-month)	Escalator (%)
[redacted]								

Project Name	Resource Type	Location	Capacity	COD	Owner	PPOA Price ($/kWh)	Monthly Capacity Payment Price ($/MW-month)	Escalator (%)
[redacted]								

Table 55: Tranche 2 Projects

Project Name	Resource Type	Location	Capacity	COD	Owner	PPOA Price ($/kWh)	Monthly Capacity Payment Price ($/MW-month)	Escalator (%)
[redacted]								

Table 56: Tranche 4 Projects

Project Name	Resource Type	Location	Capacity	COD	Owner	Monthly Capacity Payment Price ($/MW-month)	Escalator (%)
[redacted]							

6.1.3 Genera Fixed Units (Thermal and BESS units)

Genera PR is promoting the development of energy generation projects that include both thermal and BESS.[113] LUMA expects that these projects will strengthen Puerto Rico's energy system by improving the grid's reliability and resiliency.

[113] See Puerto Rico Energy Bureau Case Number NEPR-MI-2021-0002.

Table 57: Genera Thermal and BESS Units

Project Name	Resource Type	Location	Capacity	COD	Owner
[redacted]					

6.1.4 ASAP BESS (Phase 1 and 2)

The Accelerated Storage Addition Program (ASAP) is designed to integrate BESS into Puerto Rico's electric system. To achieve this, LUMA will implement ASAP to integrate BESS into existing power generation facilities.

Table 58: ASAP BESS Projects

Project Name	Resource Type	Location	Capacity	COD	ELCC	Owner
[redacted]						

[redacted]

6.1.5 Emergency Generation

PREB has requested that 800 MW of emergency generation be added to the Puerto Rico system as a temporary addition to support the current shortfall in reliable capacity.[114] LUMA has estimated the emergency generation will be added in four 200 MW blocks of generation at successive dates beginning in October of 2025. Each 200 MW package will consist of six LM2500 1x0 each with an estimated capacity of 33.3 MW, and all other characteristics will be the same as the generic LM2500 unit. The emergency generation is assumed to be available for operation until six months after the planned COD date of the Energiza 460 MW unit. Table 59 provides a summary of the characteristics assumed in the PLEXOS modeling.

Table 59: Emergency Generation

Project Name	Resource Type	Location	Capacity	COD	Owner	Anticipated Service Life	Heat Rate	Assumed Lease Cost	Fixed O&M Costs
Aguirre	Natural gas	Ponce ES	200	Oct-25	Unknown	Jan-29			
Aguirre	Natural gas	Ponce ES	200	Jan-26	Unknown	Jan-29			
Costa Sur	Natural gas	Ponce OE	200	Mar-26	Unknown	Jan-29			
Costa Sur	Natural gas	Ponce OE	200	Jun-26	Unknown	Jan-29			

6.1.6 4x25 MW BESS for Transmission System

The 2025 IRP also includes a 4x25 BESS project that provides for four 25 MW BESS, each with an assumed 100 MWh (4-hour) energy storage capacity. The units are designed to meet operational regulations, supporting fast-frequency response and system stabilization. The purpose of these batteries requires them to be charged "most of the time," but with enough headroom to switch between charge mode (in response to high-frequency conditions) and a discharge mode (in response to low-frequency conditions). Based on their planned function, the 4x25 BESS project will contribute to operating reserves but will not contribute to reserve margin, energy, or capacity requirements for normal operations.

Table 60: 4x25 MW BESS for the Transmission System

Project Name	Resource Type	Location	Capacity	COD
BESS Barceloneta	BESS	Arecibo	25	Feb-28
BESS Manatí	BESS	Arecibo	25	Feb-28
BESS Aguadilla	BESS	Mayagüez	25	Feb-28
BESS San Juan	BESS	San Juan	25	Feb-28

*Note: Costs and technical characteristics used for these batteries match the generic BESS data.

[114] See Puerto Rico Energy Bureau Case Number NEPR-MI-2023-0004.

6.2 Energy Resource Technologies Review

In addition to the fixed decision energy resource options, LUMA reviewed energy resource technologies that might reasonably be considered for modeling purposes. For the 2025 IRP, LUMA evaluated a range of potential resource technologies. Assessing a range of energy resource technologies enabled us to determine a variety of future pathways, system flexibility, and resources that align with evolving energy needs, cost-effectiveness, and public policy objectives.

Although LUMA initially screened a wide range of generation and storage technologies during the 2025 IRP development process, it did not select all for further consideration in the modeling analysis. The exclusion of some technologies was based on several factors, including technological maturity, high capital or operational costs or limited commercial operational experience.

In some cases, technologies lacked proven performance at the utility scale. In other cases, technologies presented logistical or operational constraints that made their deployment in Puerto Rico impractical. This screening process ensured that the resource plan development focused on realistic and cost-effective solutions, aligned with the Island's energy transition goals, reliability standards, and policy mandates.

Table 61 shows a list of technologies considered and compares it with the list of energy technologies incorporated in the 2025 IRP study. The report summarizing LUMA's review of the energy resource technologies can be found in Appendix 5. The estimated costs and characteristics of the energy resource technologies included in the 2025 IRP can be found in Part 7- Assumptions and Forecasts.

Table 61: Technologies Considered in the 2025 IRP

Energy Technologies Screened	Energy Technologies Incorporated in the 2025 IRP
1. Biodiesel	1. Liquefied natural gas
2. DBESS and UBESS	2. Biodiesel
3. Distributed and utility-scale solar PV	3. Distributed and utility-scale solar PV
4. Geothermal	4. DBESS and UBESS
5. Hydroelectric	5. Hydroelectric
6. Hydrogen	6. Wind (onshore)
7. Liquefied natural gas	
8. Municipal waste energy	
9. Ocean thermal energy conversion	
10. Other biofuels	
11. Renewable diesel	
12. Small modular reactor	
13. Wave and tidal system	
14. Wind (onshore and offshore)	

6.3 New Distributed-Generation Resource Identification

Distributed energy resources (DER) include distributed photovoltaics (DPV) and distributed battery energy storage systems (DBESS) under utility control. Additionally, these resources align with objectives aimed at enabling a decentralized generation. The DER growth projections, across different implementation levels (base, high, and low), over the 2025 IRP planning horizon, along with the reasoning behind them, are presented in Section 3: Load Forecast.

While the 2025 IRP incorporates a significant amount of DBESS across the planning horizon, it is expected that only a portion of these systems will fall under direct utility control. As a result, only the portion of the customer-owned DBESS that LUMA expects will enroll in programs offering customer incentives in exchange for allowing the utility to control the DBESS or use it for the utility's benefit through third parties, such as virtual power plants (VPPs), will be modeled as dispatchable assets within the utility's resource plans. Table 62 summarizes the annual level of controlled DBESS that is forecasted to be available for dispatch, assisting in meeting the system's needs.

Furthermore, LUMA has assumed that customers participating in these programs will allocate only a portion of their battery's total energy storage capacity for utility dispatch. In the 2025 IRP, the base forecast assumes customers will enroll an average of 30% of their total energy storage capacity for utility dispatch. The high level of DBESS control shown in Table 62 assumes that customers will enroll 100% for their energy storage capacity for utility dispatch. Both the base and high case are modeled in the 2025 IRP with no limits on the number of events or durations under which the utility can call for dispatch of the customer's own DBESS enrolled in the program. LUMA understands that an actual DBESS program may require limits on the number of events and the duration when the utility can call for dispatch control of the DBESS.

LUMA considers the percentage of customers enrolled in the high version and the corresponding share of their energy storage capacity (i.e., 100% of their battery capacity) to be significantly higher than what LUMA can realistically envision in future Puerto Rico programs. While LUMA deems the development of a cost-effective DBESS control program as a worthwhile initiative, it believes that the resource modeling results for the high case (i.e., Scenario 13) should be used solely for informational purposes, given their unrealistic expectations, and not as the basis for recommending a DBESS program at this time. DBESS systems not enrolled in control programs are non-dispatchable and, therefore, are excluded as energy resources in the 2025 IRP.

Table 62: Level of DBESS Control

Level of DBESS Control (%)															
Scenario	**2025**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Base	0	3	7	11	15	16	17	18	19	20	21	22	23	24	25
High	0	6	14	22	30	34	38	42	46	50	52	54	56	58	60

LUMA also has a Customer Battery Energy Sharing (CBES) program currently in operation and deployed with customers. While this program has successfully attracted meaningful enrollment in a short period, it is designed for the dispatch of customer-owned DBESS under certain emergency events. The 2025 IRP is designed to provide sufficient energy resources and reserves to avoid emergencies; therefore, it does not include the CBES program in its energy resources.

6.4 New Demand-Side Options Identification

LUMA has included a forecast of demand-side programs as part of the 2025 IRP. LUMA believes these programs are crucial elements to include in a comprehensive plan for cost-effective energy resources.

They contribute to managing electricity demand, potentially reducing or deferring the need for new energy generation, thereby balancing energy supply and demand to meet future energy needs.

LUMA has included the following demand-side options for the development of the 2025 IRP:

- **Energy efficiency (EE):** In this option, LUMA assessed programs designed to reduce energy use without reducing the quality of the services provided. *Part 3: Load Forecast* includes a description of various residential, commercial, industrial, and street lighting energy efficiency measures, the potential energy savings associated with them (considering different levels of implementation), and the costs associated with implementing these measures.
- **Demand response (DR):** In this option, LUMA assessed systems to reduce power usage during high-demand periods or when the grid is stressed. *Part 3: Load Forecast* includes a description of the different response programs for residential, commercial, industrial, and electric vehicle demands. This section also covers the potential demand reduction and the associated costs of different DR programs.
- **Electric vehicles (EVs):** In this option, LUMA assessed the implications of increased demand caused by the implementation and growth of EV shares. *Part 3: Load Forecast* includes a description of the different types of vehicles, an estimation of their market share in Puerto Rico for the planning horizon, and the potential electricity demand caused by EVs.
- **Combined heat and power (CHP):** In this option, LUMA assessed the impact of existing and planned CHP systems in Puerto Rico on the electric system. *Part 3: Load Forecast* includes an estimation of the effects of CHP over the 2025 IRP planning horizon.
- **Distributed solar photovoltaic (DPV):** In this option, LUMA assessed the impact of existing and planned DPV systems in Puerto Rico on electricity demand. *Part 3: Load Forecast* includes an estimation of the impact of DPV across different implementation levels (base, high, and low) over the 2025 IRP planning horizon. Based on the Energy Bureau's May 13, 2025, Resolution and Order in case NEPR-AP-2023-0004, only the controlled DBESS, developed from the base DPV forecast, was considered in the scenarios modeling.
- **Distributed battery energy storage systems (DBESS):** In this option, LUMA assessed the impact of existing and planned DBESS systems in Puerto Rico on electricity demand. *Part 3: Load Forecast* estimates the effect of DBESS across different implementation levels (base, high, and low) over the 2025 IRP planning horizon. Since the Energy Bureau's May 13, 2025, Resolution and Order in case NEPR-AP-2023-0004 requested consideration of only the base DPV forecast in the scenario modeling, and most DBESS are installed in conjunction with a DPV system, LUMA decided to use only the base DBESS forecast in the modeling. LUMA felt that using the base-level DBESS forecast would be the most aligned forecast with the base DPV forecast ordered by the Energy Bureau.

LUMA has assessed the available cost-effective energy efficiency measures and demand response programs, and their effectiveness and associated implementation costs throughout the planning period. Additionally, the 2025 IRP addresses critical constraints related to the acquisition of these resources, including ramp rates, expected lifetime, and annual availability. By integrating these considerations, LUMA aims to provide a robust framework for sustainable energy management and resource optimization.

6.5 Grid Defection Study

The growing penetration of distributed energy resources (DER) is reshaping the structure and economics of electric systems worldwide. In Puerto Rico, this transformation has immediate relevance. Customer self-generation, once viewed as supplementary, is now challenging the centralized utility model through both growing load defection and the potential for grid defection. Differentiating between load defection and complete grid defection is critical for effective strategic planning and informed rate design. Load defection refers to scenarios where customers significantly reduce, but do not eliminate reliance on the centralized electric system. A customer with a DPV system that generates most or all the customer's energy needs is an example of load defection. In contrast, grid defection refers to cases where customers fully disconnect from the utility grid, meeting all their electricity needs independently through onsite generation. Both phenomena can alter utility revenue, infrastructure planning, cost of service, and rate equity. This section explores the potential of grid defection by examining customer motivations and reviewing data on its occurrence.

DERs can include numerous energy sources, including but not limited to solar photovoltaic (PV) systems, wind turbines, battery energy storage systems (BESS), combined heat and power (CHP) units, microturbines, internal combustion engines, fuel cells, and even electric vehicles (EVs) acting as mobile storage.[115] Depending on the utility costs and reliability performance, these systems can provide economic savings, improved reliability in customers' households, and operational autonomy, making them attractive in regions with high electricity costs and grid reliability challenges. Their flexibility and scalability have made DERs increasingly popular among residential, commercial, and industrial users seeking cost savings, resilience, and autonomy.

Reliability may be a critical driver for grid defection, especially in Puerto Rico. In regions where customers experience frequent outages, voltage instability, or slow recovery after extreme weather events, the ability to control one's own power supply becomes highly valuable. Households and businesses are increasingly motivated to defect from the grid not to reduce costs, but to ensure continuous, high-quality power. For example, in the U.S., reliability concerns have already influenced the adoption of residential solar-plus-storage systems, especially in areas affected by wildfires and blackouts such as California and Texas.[116]

From a planning and policy standpoint, DER adoption introduces both opportunities (enhanced resilience, localized generation, lower emissions) and risks (inequity, cross-subsidization, infrastructure hosting ability, unanticipated disconnections). In regions with aging infrastructure or economic uncertainty, such as Puerto Rico, this transformation has the potential to foster a more decentralized and resilient energy future or to deepen social inequities, depending on how grid defection trends are managed and regulated. Therefore, detecting and quantifying grid defection is essential, not only for utilities and regulators, but for any stakeholder investing in long-term energy equity and reliability.

6.5.1 Residential Solar Photovoltaic Adoption and Potential Grid Defection

Puerto Rico's Net Energy Metering (NEM) program established by Act 114-2007, known as the Puerto Rico Net Metering Program Act, has played a central role in accelerating the adoption of distributed photovoltaic (DPV) systems. Article 3.5 of Act 17-2019, amended Act 114-2007 to provide for eligible NEM customers to receive retail-rate credit for each kilowatt-hour exported to the grid, with accumulated credits

[115] Diversegy. (2023). What are distributed energy resources (DERs)? https://diversegy.com/distributed-energy-resources/
[116] Bronski, P., Chew, B., Fox-Penner, P., Neubauer, M., Tam, C., Puda, S., & Powers, J. (2014). The economics of grid defection: When and where distributed solar generation plus storage competes with traditional utility service. *Rocky Mountain Institute.* https://rmi.org/insight/economics-grid-defection/

settled annually.[117] Additionally, Article 3.9 of Act 17-2019, amended Act 114-2007 to permit systems under 25 kW to interconnect automatically once certified by a licensed engineer or electrician, bypassing a formal study before interconnection, even when the distributed generation (DG) system exceeds the 15% feeder capacity threshold or causes voltage fluctuations or other safety issues.

Furthermore, Article 8.1 of Act-17-2019 amends Section 4030.17 of the Puerto Rico Internal Revenue Code to exempt solar and energy storage equipment, including accessories and leases, from the sales and use tax (IVU, for its Spanish acronym). To qualify, the equipment must include a five-year warranty and meet the standards established by the Energy Public Policy Program of the Puerto Rico Department of Economic Development and Commerce.

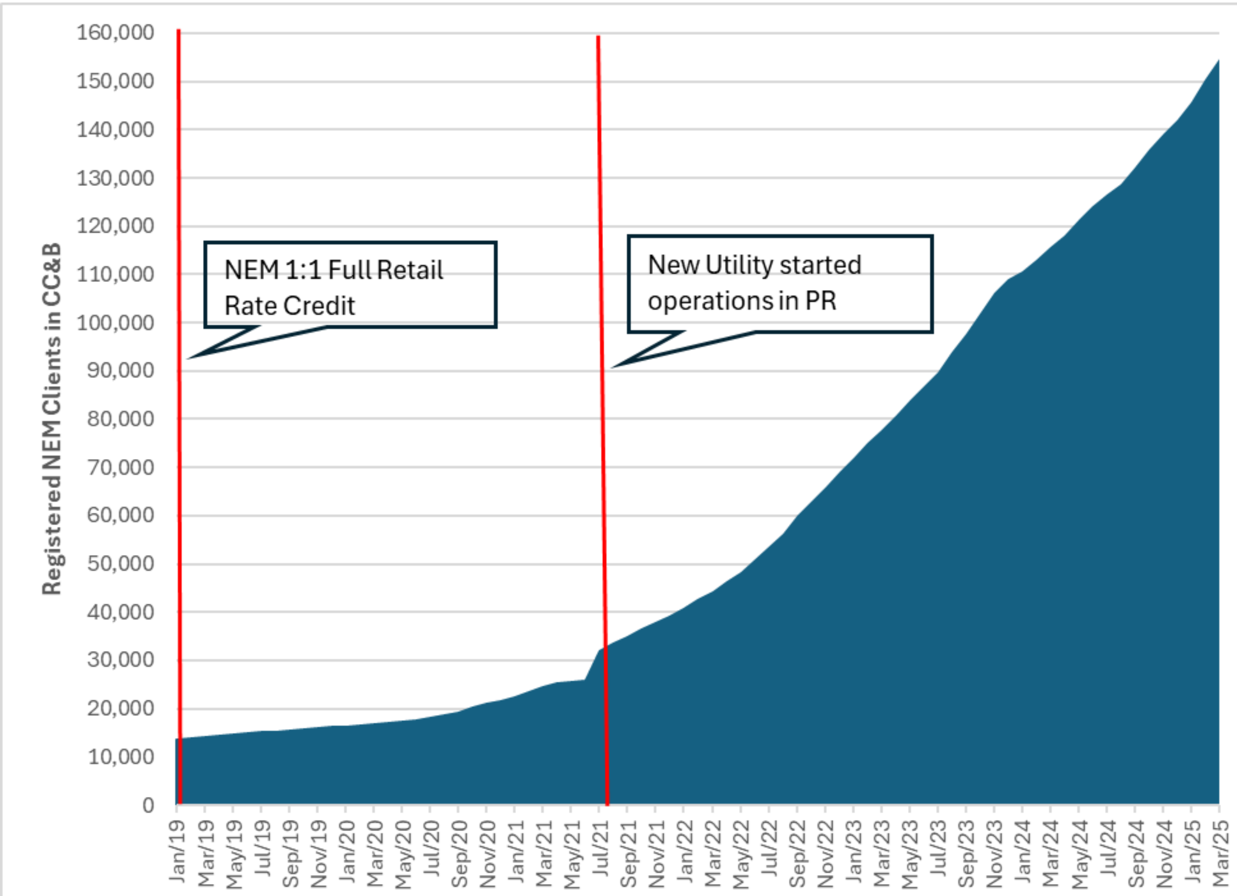
As of March 2025, over 140,000 residential customer accounts in Puerto Rico are equipped with PV systems. Between fiscal year (FY) 2021 and FY2025, approximately 68% of these customers also installed BESS, with adoption accelerating sharply in recent years. Notably, in FY2024 and FY2025, nine out of 10 new PV installations have included battery storage.[118]

From FY2021 to FY2025, the average installed residential PV system ranged from 5 kW to 7 kW, typically paired with one battery unit, with an average storage capacity of 15.6 kWh.[119] This level of behind-the-meter infrastructure enables measurable load defection and a reduction in grid consumption as it allows customers to rely on self-generated and stored energy increasingly.

[117] Oficina de Gerencia y Presupuesto de Puerto Rico. (2019). Ley de Política Pública Energética de Puerto Rico. *Gobierno de Puerto Rico.* https://bvirtualogp.pr.gov/ogp/Bvirtual/leyesreferencia/PDF/17-2019.pdf
[118] Internal Utility Data as of March 2025
[119] Internal Utility Data as of March 2025

6.5.2 Economic and Reliability Factors Affecting Adoption (Public Policy as a Catalyst for Adoption)

Figure 59: Registered Net Energy Metering Clients in Customer Care & Billing (CC&B)



The continued growth in residential solar PV adoption in Puerto Rico can be attributed to deliberate public policy interventions that have reshaped the Island's energy landscape. Following the devastation caused by Hurricane María in 2017, Puerto Rico has faced persistent reliability issues, including frequent service interruptions and aging infrastructure.[120] In response, the enactment of Act 17-2019 sought to promote the adoption of DERs—especially residential PV systems and BESS—as a strategy to strengthen energy resilience and mitigate customer exposure to outages.

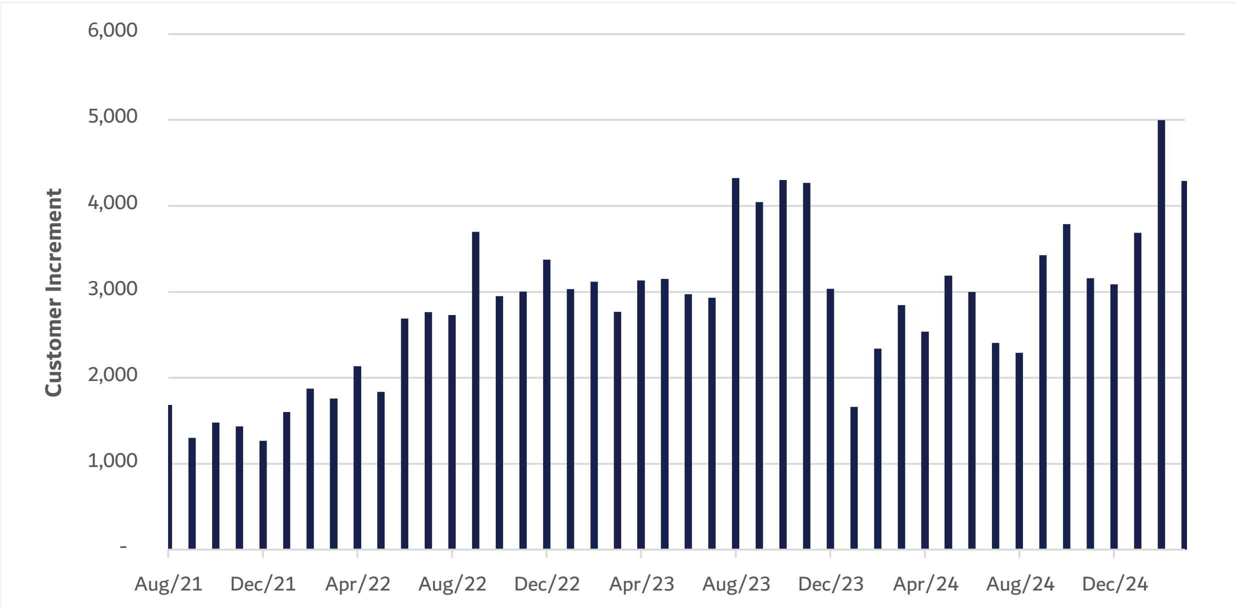
In June 2021, LUMA took over interconnections for DG systems, leading to a marked increase in residential installations.[121] Since assuming responsibility for DG interconnections in June 2021, LUMA has implemented operational efficiencies that significantly improved processing times and reduced the backlog of NEM applications inherited from PREPA. The legacy system was regionally fragmented and lacked coordination, resulting in delays even for expedited projects under 25 kW. In response, LUMA

[120] NBC News. (2025, April 9). Puerto Rico's power grid in critical condition as frustration grows [Article]. *NBC News*. https://www.nbcnews.com/news/latino/puerto-rico-hurricane-maria-anniversary-power-grid-rcna47729
[121] Rico, S. (2021). LUMA Energy promete "ponerse al día" con el Programa de Medición Neta. *NotiCel*. https://www.noticel.com/legislatura/ahora/20210916/luma-energy-promete-ponerse-al-dia-con-el-programa-de-medicion-neta/

centralized key functions, including validation, billing, and meter changes, under dedicated teams, enabling consistent and faster processing across regions.

As a result, LUMA has steadily increased throughput, now activating over 4,000 applications per month. Portal improvements and enhanced communication tools, such as a public interconnection queue, have further improved transparency and user experience.

Figure 60: Month-over-Month Net Energy Metering Enrollment Trend



In addition, Act 17-2019 established ambitious targets, such as achieving 100% renewable energy generation by 2050 and emphasizing the integration of DG, microgrids, and consumer participation.[122] Through incentives such as tax exemptions for battery systems and streamlined interconnection protocols, DERs were repositioned from niche alternatives to core components of the energy system.

Public policy has also indirectly facilitated the growth of consumer financing. By providing long-term regulatory certainty and lowering procedural barriers, the legislation created favorable conditions for third-party providers to offer accessible financing options, including leases, loans, and power purchase agreements to residential customers. While the average monthly payment for a residential PV and BESS is approximately $248—slightly higher than the $200 cost of consuming 800 kWh from the electric system—many consumers are willing to pay this premium in exchange for improved reliability and energy autonomy, rather than solely for cost savings.[123]

Together, policy direction, operational improvements, enhanced system reliability, and greater access to financing have collectively accelerated the deployment of residential solar and storage systems. These

[122] Oficina de Gerencia y Presupuesto de Puerto Rico. (2019). Ley de Política Pública Energética de Puerto Rico. Gobierno de Puerto Rico. https://bvirtualogp.pr.gov/ogp/Bvirtual/leyesreferencia/PDF/17-2019.pdf

[123] Estimated monthly payment based on current market trends, system sizing, and financing assumptions as of 2024. Calculations are illustrative and provided in the Appendix (Excel). This estimate does not reflect potential future changes in policy, pricing, or financing conditions.

systems have evolved into not just alternatives to centralized service but practical and resilient solutions to Puerto Rico's enduring energy challenges.

6.5.3 Potential For Grid Defection

LUMA estimates that the average residential NEM customer displaced approximately 278 kWh per month in calendar year 2023. This figure accounts for approximately 4% of total residential electricity consumption. The estimate was derived using an engineering-based approach that compared simulated PV generation with actual export data, suggesting substantial onsite self-consumption.[124] While this level of load defection is relatively modest, continued NEM growth is likely to increase its system-wide impact, particularly for grid planning and rate design.

Although partial load defection is well-documented, full grid defection—where customers completely disconnect from the centralized grid—remains economically and technically impractical for most residential users. A key barrier is the significant storage capacity required to maintain reliability during periods of low solar generation. For example, a household consuming 800 kWh per month would require approximately five 13.5 kWh batteries and sixteen 400-watt PV panels to sustain two consecutive days of minimal sunlight. The monthly lease cost for this configuration is estimated at $535, equivalent to about $0.73 per kWh.

In contrast, grid-connected customers currently pay about $200 per month for the same consumption (at approximately $0.25/kWh). Financing a solar-plus-storage (PV and BESS) system while remaining connected to the grid typically results in a lower cost, around $248 per month, or $0.31/kWh. While this is moderately higher than current utility rates, many customers consider the premium acceptable in exchange for energy autonomy and improved reliability.

Moreover, the PREPA Fiscal Plan developed by the Financial Oversight and Management Board (FOMB) projects utility rates could rise to approximately $0.31/kWh by FY2026,[125] effectively closing the cost gap between grid consumption and partial self-sufficiency. Importantly, NEM customers benefit from a 1:1 credit structure, where exported energy is offset against usage at the retail rate. This allows customers to significantly reduce their bills, often paying only a basic service fee—currently about $4/month—, representing approximately $0.07/kWh of the average rate. While this charge is projected to double to approximately $8/month by FY2027, the economic incentive to remain grid-connected will persist.

Looking further ahead, utility rates are forecasted to rise to approximately $0.45/kWh by FY2040 and potentially reach approximately $0.55/kWh when debt and pension recovery charges are included.[126] Nevertheless, unless major policy or regulatory changes alter the structure of service charges, NEM customers may continue to offset most of these increases. As a result, partial grid defection—rather than full disconnection—is likely to remain the dominant strategy for most residential users in the near to medium term.

While the pace of adoption remains strong, affordability has natural limits. Ongoing improvements in PV and battery manufacturing are expected to lower hardware costs. However, future analyses should account for shifts in financing terms, interest rates, and broader market conditions. Economic sensitivity

[124] Balbis, E., Steele-Mosey, P., Bergeron, F., & Molitor, V. (2024). Improvement 5: Historic displaced load – Solar PV estimated displaced consumption distributed generation net energy metering customers (Ref. No. 217196). *Guidehouse, Inc.*

[125] Financial Oversight and Management Board for Puerto Rico. (2025). F*iscal plan for the Puerto Rico Electric Power Authority*. PREPA - 2025 Certified Fiscal Plan.pdf - Google Drive

[126] Financial Oversight and Management Board for Puerto Rico. (2025). F*iscal plan for the Puerto Rico Electric Power Authority*. PREPA - 2025 Certified Fiscal Plan.pdf - Google Drive

analyses will be crucial for assessing consumer responses to evolving financial dynamics, determining key economic thresholds for adoption, and forecasting the likelihood of residential grid defection.

Ultimately, these insights are crucial for assessing the long-term viability of Puerto Rico's NEM program and informing decisions regarding policy development and infrastructure planning.

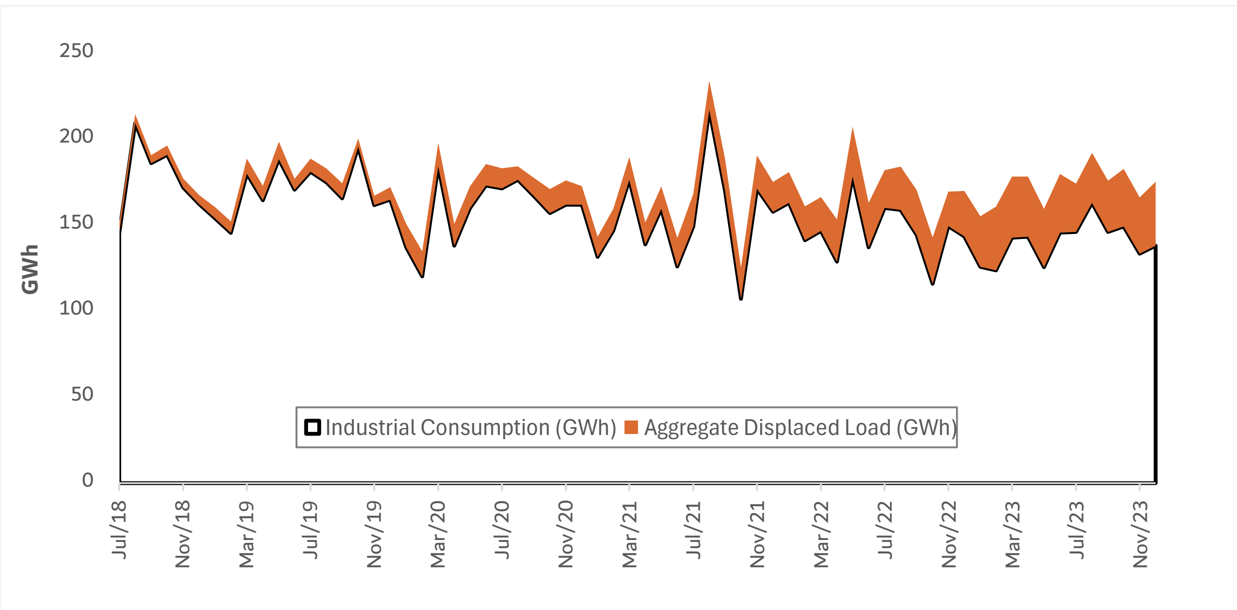
6.5.4 Combined Heat and Power Potential Grid Defection

Recent data indicate that load defection in Puerto Rico is becoming a widespread and measurable trend, particularly among large industrial and commercial customers deploying CHP systems. While most of these customers remain connected to the grid and continue to rely on it for backup during CHP downtime or maintenance, they are increasingly generating most of their electricity needs onsite. A recent analysis conducted by Guidehouse on behalf of LUMA confirms that this segment is reducing its volumetric electricity consumption significantly.

6.5.5 Combined Heat and Power Adoption Trends and Displaced Load

Guidehouse's *Improvement 5: Historical Displaced Load – Combined Heat and Power (2024)*, identified 43 large industrial and commercial customers who have significantly reduced their electricity consumption from the electric system through CHP deployment. Collectively, these customers displaced approximately 34 GWh per month in 2023, totaling over 400 GWh for the entire year, as shown in Figure 61.

Figure 61: Monthly Industrial Billed Load vs. Estimated CHP-Displaced Load



The average installed CHP capacity among these customers is approximately 3,953 kW, a scale typically sufficient to meet full onsite energy requirements. This displacement trend is accelerating, particularly across major industrial and commercial rate classes, signaling a broader shift toward energy autonomy.

Despite these findings, the analysis relies on monthly billing data without high-resolution metering. Improved monitoring, including hourly or real-time data, would allow for a more precise assessment of CHP-related impacts.

Although fewer than five of these 43 customers have completely ceased volumetric electricity consumption from LUMA, their defection still materially reduces revenue from large-load customers. This growing trend has direct implications for utility cost recovery, rate design, and long-term planning.

6.5.6 Reliability as the Primary Driver of Combined Heat and Power Deployment

Customer decisions to adopt CHP are driven by more than just economics. According to LUMA's 2023 customer survey of CHP-equipped industrial clients, all respondents cited reliability as their primary motivation for installing onsite generation.[127]

This aligns with broader energy developments across the Island. Major fuel suppliers have expanded their liquefied natural gas (LNG) infrastructure to serve large energy users, and several manufacturers have publicly declared themselves to be fully energy independent.[128] [129] These trends highlight a shift toward self-sufficiency and resilience, particularly among Puerto Rico's most significant commercial and industrial operations.

6.5.7 Monitoring Challenges and Path Forward

Although CHP disclosures have averaged seven new reported systems per year over the last four years, underreporting remains a concern.[130] In practice, many systems appear to operate without submitting the technical documentation required under interconnection regulations, limiting LUMA's ability to track and measure their true impact. Current interconnection regulations, 8915 and 8916, do not cover CHPs. Due to the lack of a regulatory framework governing the interconnection of these types of systems, many systems do not notify or submit a request to LUMA to interconnect. The adoption of an interconnection regulation that covers these systems would help provide more visibility.

This lack of compliance reduces visibility into load trends and complicates forecasting, planning, and rate design. Addressing this gap through enhanced enforcement and data integration will be key to understanding and managing the broader effects of grid defection.

CHP-driven load defection is a material and growing trend that is reshaping how Puerto Rico's largest industrial and commercial customers interact with the grid. These customers are not severing ties with the utility but are instead reducing their reliance on it by generating most of their electricity onsite, using the grid primarily as a backup. While billing data provides useful estimates of displaced load, the absence of full compliance and high-resolution monitoring continues to obscure the true scale of this shift. Enhancing interconnection visibility and data quality will be critical for LUMA to anticipate future impacts on load forecasting, rate design, and infrastructure planning.

[127] LUMA Energy. (2023). *CHP Customer Survey Results.* Internal data shared with Guidehouse as part of Improvement 5 project documentation. Only four customers responded the survey.
[128] González, J. (2023, August 11). Crowley expande su operación de gas natural en Peñuelas. *El Nuevo Día.* https://www.elnuevodia.com/negocios/empresas-comercios/notas/crowley-expande-su-operacion-de-gas-natural-en-penuelas/
[129] Rosario, F. (2023, January 26). Bacardí logra su independencia energética. *Primera Hora*. https://www.primerahora.com/noticias/puerto-rico/notas/bacardi-logra-su-independencia-energetica/
[130] LUMA Energy internal estimate (2024). Based on annual rate of voluntary DG/CHP disclosures.

Section 7:

Assumptions and Other Forecasts

7.0 Assumptions and Forecast

7.1 Model Assumptions Documentation

7.1.1 Fuel Prices

This section presents the methodology used to estimate the price of each fuel considered in the 2025 IRP production costs and expansion model. The 2025 IRP involves multiple fuel types over the 20-year planning horizon. The list of fuels for which forecasts have been developed includes:

- Liquefied natural gas (LNG) delivered to EcoEléctrica and Costa Sur
- Liquefied natural gas (LNG) delivered to San Juan
- Liquefied natural gas (LNG) delivered to San Juan and then trucked to other plant sites
- Coal
- Residual fuel oil (RFO)
- Ultra-low sulfur diesel (ULSD)
- Biodiesel blended with ULSD
- Renewable diesel (R100)

7.1.2 Base Fuel Price Forecasts

Table 63 lists the base forecasts for each fuel type incorporated in the 2025 IRP. All prices are stated on a delivered, nominal basis.

Table 63: Base Fuel Price Forecasts*

Year	EcoEléctrica	LNG SJ	Coal	Heavy Fuel Oil	Diesel	Biodiesel	Renewable Diesel
[redacted]							

Year	EcoEléctrica	LNG SJ	Coal	Heavy Fuel Oil	Diesel	Biodiesel	Renewable Diesel
[redacted]							

*All prices in $/MMBtu.

Natural Gas Price Forecast

To develop the natural gas price forecast, LUMA's technical consultant analyzed existing contracts with Naturgy and New Fortress Energy. These two entities currently import natural gas in the form of LNG to the primary gas-fired power plants at San Juan and Costa Sur. In these contracts, the fuel prices are based on cost components that include the unit cost and the unit fuel cost, where the unit fuel cost is the Henry Hub natural gas futures index price multiplied by 1.15, and the unit cost accounts for the transportation and delivery elements of the total fuel cost and varies by supply period.

In the 2025 IRP's forecast, the unit fuel cost forecast for 2025 through 2028 was based on Henry Hub futures from December 2023 to January 2024, and it was assumed that the unit cost would remain constant. For the period encompassing 2028 through 2044, the 2023 Energy Information Administration's (EIA) Annual Energy Outlook (AEO) reference case annual growth rate for Henry Hub spot prices was applied to develop the long-term natural gas price forecast.

Price forecasts are provided for LNG imported into the existing LNG import and offloading locations in the San Juan transmission planning area (TPA) and in the Ponce OE TPA, where existing generating facilities currently utilize imported LNG. The San Juan generation plant is in the San Juan TPA, and the Costa Sur and EcoEléctrica generating facilities are in the Ponce OE TPA.

The 2025 IRP included the option to build new natural gas-fired power plants in any TPA. However, the 2025 IRP does not consider any new natural gas pipelines, except for the possible need to expand the capacity of existing natural gas facilities at the San Juan plant and the EcoEléctrica Costa Sur plants, which are used for offloading shipments of LNG, delivery, storage, and refilling of LNG trucks. For locations other than the current two import locations (i.e., San Juan plant and the EcoEléctrica plant, which also supplies the Costa Sur plant), it was assumed that LNG would be trucked from one of the two existing LNG import locations to the other remote generation locations and then stored onsite in ISO containers or other fixed storage tanks. The Genera generation fleet already includes natural gas-fired generation located in Palo Seco, which is supplied by trucked LNG originating from the San Juan LNG delivery location and stored onsite at Palo Seco. For the 2025 IRP, LUMA has assumed that San Juan will be the sole source of LNG for all trucked LNG. However, an additional or alternate trucked LNG filling station at Costa Sur remains an option.

For remote sites in Puerto Rico located away from an LNG import location, LUMA assumed that LNG would be transported to the power plant sites using dedicated LNG tanker trucks, as shown in Figure 62, or via LNG International Standardization Organization (ISO) containers, as shown in Figure 63. LNG ISO containers are standardized, intermodal containers that can be stacked on standard container ships and offloaded to container truck beds for transport. The ability to transport LNG fuel on standard container ships in LNG ISO containers and use the same containers to deliver the gas via trucks to locations in Puerto Rico provides an alternative delivery method to specialized barges and ships that are designed and dedicated to the marine transport of LNG.

Figure 62: Dedicated LNG Tanker Truck

Figure 63: LNG ISO Tanks Stacked and Loaded onto a Standard Container Truck

The standard lengths of ISO containers are 20 feet and 40 feet; and a length of 40 feet is common for the transportation of LNG. The photos in Figure 63 show 20-foot containers. ISO containers for LNG transport are made of stainless steel and are insulated, pressure-tight tanks capable of transporting LNG at temperatures as low as -260 degrees Fahrenheit. Once the containers arrive at the destination, the LNG is re-gasified and used as a fuel source for power generation. Some of the ISO containers have onboard regasification equipment, while others rely on separate mobile or permanently installed regasification facilities at the generation sites.

One of the advantages of using ISO containers for natural gas transportation is their flexibility and cost-effectiveness, offering an efficient solution for delivering LNG to remote locations that lack access to shipborne deliveries or pipelines. Once delivered to a remote generation site, the ISO containers can remain to provide onsite fuel storage, be offloaded to fixed storage tanks installed at the site, or be immediately connected to the generators to supply fuel for energy production.

The transportation from the import location to the final point of use adds to the total delivered LNG cost. The cost of transporting LNG by truck from the import location in San Juan to a remote generation plant location is estimated to add $0.75/MMBtu to the price of the LNG fuel.

Coal Price Forecast

Table 63 lists the base forecast price of coal. All prices in the table are stated on a delivered, nominal basis. Although the forecast for coal extends to 2044, the use of coal in Puerto Rico is assumed to be phased out after 2032, when the AES power plant is expected to retire. From 2025 to 2028, the forecasted coal price is based on the previous Power Purchase and Operating Agreement between AES Puerto Rico, L.P., and the Puerto Rico Electric Power Authority (PREPA). LUMA extended the coal forecast for the period from 2029 through 2044 using the 2023 Energy Information Administration's (EIA) Annual Energy Outlook (AEO) reference case and the annual growth rate for the electric power cost of coal.[131]

Residual Fuel Oil Forecast

Table 63 lists the base price forecast for heavy fuel oil, referred to in the 2025 IRP as residual fuel oil (RFO). All prices are stated on a delivered, nominal basis. RFO has also been referred to in the past LUMA and PREPA documents as heavy fuel oil, or Bunker C. The forecast for RFO prices utilized LUMA's current pricing methodology, which involves indexing the RFO prices to NYMEX Brent Crude Oil Futures Settlement prices, plus an added cost component. This adder is based on the average difference between marine fuel prices (0.5%) and Brent Daily prices in November 2023, plus a predetermined transportation premium. To forecast prices for the 2025-2027 period, the average NYMEX Brent Crude Oil Futures prices between December 2023 and January 2024 were calculated and used. For the years 2027 onward, LUMA's technical consultant utilized the 2023 EIA's AEO reference case growth rate for RFO in all sectors.

Ultra Low Sulfur Diesel Forecast

Table 63 lists the base price forecast for ultra-low sulfur diesel (ULSD) used in the 2025 IRP. All prices are stated on a delivered, nominal basis. The pricing of ULSD is indexed on CME Group Platts NY Harbor ULSD Futures - Settlements and CME Group Platts Gulf Coast Waterborne, with an additional agreed-upon price adder. To develop a fuel price forecast for the 2025 IRP, LUMA's technical consultant utilized the December 2023 and January 2024 Platts NY Harbor and Platts Gulf Coast Waterborne futures prices for the period spanning 2025 through 2027. Black and Veatch applied the 2023 AEO reference case growth rate for diesel in the electric power sector to develop the long-term diesel price forecast for the period encompassing 2027 through 2044.

[131] The coal forecast was initially developed through 2028, in line with the original planned retirement of AES Units 1 and 2. LUMA extended this forecast from 2029 to 2044, using the 2023 AEO reference case annual growth rate for the electric power cost of coal, applying the same methodology and data source as LUMA's technical consultant used for other fuels.

Biodiesel and Renewable Diesel Forecast

Table 63 lists the base price forecast for biodiesel and renewable diesel used in the 2025 IRP. The fuel price shown reflects a blend of biodiesel and diesel in the biodiesel forecast, and a blend of renewable diesel and diesel in the renewable diesel forecast. The blends for both fuels are based on an increasing percentage of biodiesel and renewable diesel over time. The biofuel considered under the 2025 IRP begins with a blend of 62% biofuel and 38% diesel in 2025, increasing to 98% biofuel by 2044. This projected blend is reflected in the price forecast in Table 63. All prices are stated on a delivered, nominal basis.

Biodiesel and renewable diesel are important fuel options to consider when planning the future of Puerto Rico's power sector. Both are renewable fuels that can make an important contribution to achieving renewable energy targets. In this section, the two fuels are defined, the ability to count these fuels toward the Puerto Rico renewable energy targets is discussed, and the development of the price forecast is explained.

Defining Biodiesel and Renewable Diesel

Biodiesel and renewable diesel are both biofuels. According to the EIA, the term "biofuels" refers to "liquid fuels and blending components produced from biomass materials called feedstocks."[132] The EIA publishes data on four major categories of biofuels: ethanol, biodiesel, renewable diesel, and "other biofuels" that include "renewable heating oil, renewable jet fuel […], renewable naphtha, renewable gasoline, and other emerging biofuels." Thus, it is appropriate to refer to biodiesel and renewable diesel collectively as biofuels.

Biodiesel is produced from feedstocks that, in the U.S., include vegetable oils, soybean oil, and other feedstocks that can include animal fats from meat processing, used cooking oil, and recycled grease from restaurants.[133] In other countries, rapeseed oil, sunflower oil, and palm oil are major feedstocks for biodiesel production. In the future, algae also have the potential to be a major source for biodiesel production.

Biodiesel can be blended with petroleum diesel in any ratio reflected in the product's assigned code. A "B100" biodiesel refers to pure biodiesel while B20, currently the most common blend, contains 20% biodiesel and 80% petroleum diesel.

While both biodiesel and renewable diesel can be produced using the same feedstock, their production processes differ. Biodiesel is produced through a process known as transesterification, which involves converting organic fats and oils into fatty acid alkyl esters by reacting them with alcohols and catalysts. Renewable diesel can be produced using various technology pathways and is primarily a hydrocarbon product derived from hydrotreating, as well as gasification, pyrolysis, and other biochemical and thermochemical processes.[134] Thus, renewable diesel is a hydrocarbon, while biodiesel is not. Renewable diesel is chemically equivalent to petroleum diesel and can be substituted for or blended with petroleum diesel without performance issues or conversion costs. The performance impacts of units switched to biodiesel is discussed in Section 7.2.1 Economic Conditions.

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[132] U.S. Energy Information Administration. (2023). Biofuels Explained. *Monthly Energy Review*, Renewable Energy, (September). Retrieved on April 1, 2024, from https://www.eia.gov/energyexplained/biofuels

[133] *See* (retrieved on October 1, 2025).

[134] Alternative Fuels Data Center. (n.d.) Renewable Diesel. *U.S. Department of Energy*. Retrieved on April 1, 2024, from https://afdc.energy.gov/fuels/renewable-diesel

Potential Sourcing and Transport

In the U.S., Iowa is a leader in biodiesel production and the region could serve as an important source of biodiesel for Puerto Rico. The state is home to numerous biodiesel production facilities that use a variety of feedstocks, and it has a long history of supporting renewable fuels. Iowa's implementation of a biodiesel blending requirement has helped drive demand for this low-emission fuel and reduce the state's dependence on imported petroleum. By leveraging Iowa's expertise and resources, Puerto Rico could potentially establish a reliable supply of biodiesel and promote sustainable energy practices on the Island.

Transporting biodiesel to Puerto Rico would likely involve a mix of rail and vessel transportation. Once the biodiesel arrives, it could be distributed to power plants with the help of local distributors to integrate fuel into the mix used to generate energy on the island.

Renewable diesel production depends on the availability of feedstocks and production facilities. The availability of biomass and waste feedstocks is scarce in some regions, which could limit the feasibility of specific renewable diesel production methods. Geismar, Louisiana, is currently a hub for renewable diesel production, with a diverse range of companies owning and operating facilities for producing renewable diesel. These facilities use a variety of feedstocks, including animal fats, used cooking oil, and soybean oil, to produce renewable diesel fuel that meets the same specifications as petroleum diesel but with significantly lower emissions. Renewable diesel produced in Geismar holds great potential for transport to Puerto Rico through a combination of rail and vessel transportation. Once there, the fuel could be distributed to power plants on the Island through local diesel fuel distributors' networks and infrastructure.

Biodiesel and Renewable Diesel Compliance with Act 82

The ability to count energy produced from biodiesel and renewable diesel toward the Puerto Rico Renewable Portfolio Standard (RPS) depends on the specifics of Act 82-2010, Public Policy on Energy Diversification by Means of Sustainable and Alternative Renewable Energy in Puerto Rico Act, as amended (Act 82). Section 1.4 (7) of Act 82 defines the RPS as the "mandatory percentage of sustainable renewable energy or alternative renewable energy required from each retail energy provider." Act 82 (Section 1.4 [15]) defines sustainable renewable energy as derived from:

- Solar energy
- Wind energy
- Geothermal energy
- Renewable biomass combustion
- Renewable biomass gas combustion
- Combustion of biofuels derived solely from renewable biomass
- Hydropower
- Marine and hydrokinetic renewable energy, as defined in Section 632 of the "Energy Independence and Security Act of 2007" (Public Law 110-140, 42 U.S.C. § 17211)
- Ocean thermal energy

Given the inclusion of biofuels in the list of production qualified as sustainable renewable energy, plus the previous discussion about biodiesel and renewable diesel being biofuels, the 2025 IRP assumes that both fuels, biodiesel and renewable diesel, when used to generate electricity, are renewable under Act 82.

To develop a price forecast for biodiesel, LUMA's technical consultant surveyed potential biodiesel suppliers, including Chevron Renewable Energy Group, Neste, and Targray, and obtained pricing information. Generally, biodiesel commodity prices are linked to New York Harbor Heating Oil Futures, with a nominal adder of $0.85 per gallon. The delivery prices, which refer to the costs of transporting biodiesel to its destination, are estimated to be a nominal rate of $0.80per gallon.

LUMA's technical consultant utilized the New York Harbor Heating Oil Futures from March 2024 and included the adders to determine the delivered biodiesel prices for various biodiesel blends. LUMA's technical consultant then developed and utilized a schedule for the introduction of biodiesel, with the initial phase involving a blend of 62% biodiesel and 38% diesel (B60) in 2025. Subsequently, it was assumed that there would be a gradual increase of one to two percent in the blend each year until it reaches 98% biodiesel.

Price Forecast Methodology: Renewable Diesel

LUMA's technical consultant also conducted a survey among potential renewable diesel suppliers to develop an accurate price forecast for R100 (100% renewable diesel). The price of R100 consists of two parts: the commodity price and the delivery price. Commodity prices are indexed to the New York Harbor Heating Oil Futures, with an additional nominal adder of $1.72 per gallon. The delivery prices were estimated to be a nominal rate of $0.80 per gallon, based on indicative price quotes and estimates received from a potential biodiesel and renewable diesel provider in the market.

High LNG Fuel Cost Forecasts

Based on agreement between LUMA and the Energy Bureau's consultant, the only specific alternative fuel price included in the modeling for this IRP would be a high fuel price for LNG and all other fuels are included at baseline levels for all scenarios. Table 64 lists the percentage adjustments made to both LNG baseline fuel forecasts (i.e., the LNG EcoEléctrica and LNG SJ) used in the 2025 IRP for the high LNG fuel price forecast. The table indicates the percentage adjustment that was applied to the corresponding baseline fuel forecast to determine the high fuel price.

Table 64: High LNG Fuel Price Forecast

Year	LNG Annual Adjustment to Base LNG Forecasts
2025	110%
2026	114%
2027	118%
2028	119%
2029	120%
2030	121%
2031	122%
2032	123%
2033	122%
2034	120%
2035	117%
2036	117%
2037	117%
2038	115%
2039	117%
2040	115%
2041	113%
2042	113%
2043	113%
2044	115%

High Fuel Price Forecast

In addition to the High LNG price forecast, LUMA's technical consultant created a blended High Fuel scenario. This scenario used the EIA side cases shown in , which were compared against the base case to calculate individual price ratios. Those ratios were then averaged to determine the final multipliers for each fuel type and then applied to the baseline fuel price to generate the High Fuel price forecast.

Table 65: EIA Ratios of Side Cases in the High Fuel Price Forecast – Natural Gas

Year	Low Economic Growth	High Oil Price	Low Oil and Gas Supply	Low Zero-Carbon Technology Cost	High Macroeconomic and Low Zero-Carbon Technology Cost
2025	102%	100%	145%	101%	101%
2026	104%	105%	154%	104%	105%
2027	107%	108%	156%	109%	109%
2028	108%	108%	158%	112%	112%

Year	Low Economic Growth	High Oil Price	Low Oil and Gas Supply	Low Zero-Carbon Technology Cost	High Macroeconomic and Low Zero-Carbon Technology Cost
2029	107%	107%	158%	112%	114%
2030	110%	108%	153%	115%	117%
2031	113%	107%	155%	115%	118%
2032	116%	107%	157%	115%	119%
2033	118%	104%	157%	114%	116%
2034	118%	101%	156%	113%	112%
2035	118%	98%	153%	110%	107%
2036	120%	98%	153%	110%	106%
2037	121%	97%	151%	112%	106%
2038	120%	95%	146%	110%	104%
2039	125%	94%	147%	112%	107%
2040	128%	90%	142%	109%	104%
2041	129%	88%	138%	107%	103%
2042	131%	87%	136%	107%	103%
2043	131%	87%	135%	109%	104%
2044	134%	88%	137%	112%	104%

7.1.3 Annual Emission Prices

The consideration of emission pricing has been used in some IRPs in recent years, but its use has generally been limited to greenhouse gas (GHG) emissions and to jurisdictions that have GHG or carbon emission standards. In locations with instituted regulations, markets have developed for the trading of emission credits. For example, several states on the west coast and northeastern Atlantic coast have regulations and financial markets focused on GHG emissions and pricing of emission offsets or credits. With firm regulations and an active and fluid market for emission credits, a company can choose to meet GHG emission regulations by either investing in technologies or other means to reduce their GHG emissions or by purchasing GHG emission credits, which serve to provide the right to emit the quantity of GHG emissions up to the amount of emission credits purchased.

Neither Puerto Rico's nor the U.S.'s federal regulatory agencies have established regulations for GHG emissions or the pricing and markets of associated credits or offsets. The absence of emission regulations or structured emission pricing mechanisms means that emissions from PREPA operations and the broader range of GHG emitters are not currently being quantified and monetized in a structured manner. Consequently, LUMA has not developed nor included any pricing related to emissions in the 2025 IRP analysis or in this Report.

As the landscape of energy policy continues to evolve, emission pricing may be introduced in the future. Should such regulations be established, they will need to be integrated into LUMA's planning processes to assess their potential impact on cost structures, resource adequacy, and environmental compliance.

Currently, LUMA's focus remains on exploring alternative resource strategies and sustainability measures even without a regulated emission pricing system.

7.2 General Forecast Assumptions

7.2.1 Economic Conditions

Economic conditions are discussed in Section 3 Load Forecast.

7.2.2 Environmental Regulations

Environmental regulations are discussed in Section 2 Planning Environment.

7.2.3 Other Non-Environmental Regulations (including RPS)

Non-environmental regulations are explained in Section 2 Planning Environment.

7.2.4 Utility discount rates or weighted average cost of capital limitations

LUMA used PREPA's current weighted average cost of capital of 8%.

7.2.5 Annual Debt Limitations

LUMA did not include annual or total debt limitations for this 2025 IRP.

7.2.6 Changes in Customer Load Not Caused by Utility Demand-Side Resources

Changes in customer load not caused by utility demand-side resources are discussed in Section 3 Load Forecast.

7.2.7 Changes in Customer-Sited Distributed Generation

Changes in customer-sited distributed generation are discussed in Section 3 Load Forecast.

7.3 Capital and Operating Costs

For the development of the 2025 IRP modeling, LUMA estimated the capital cost, as well as fixed operation and variable operation and maintenance (O&M) cost trajectories for energy resources that are available for potential economically justified additions to the resource plan. The following subsections describe the methodology used for those cost forecasts.

7.3.1 Solar PV

For the 2025 IRP, LUMA adopted the PR100 cost estimates for all utility-scale solar PV. The PR100 estimates were primarily derived from the National Renewable Energy Laboratory's (NREL) 2023 Annual Technology Baseline (ATB), with a geographic adjustment for Puerto Rico. The cost data found in the 2023 ATB were escalated to account for the PR100 estimated cost differential between resource projects constructed in the mainland U.S., on which the 2023 ATB costs are based, versus the higher costs seen in the bid responses received to the Tranche 1 and 2 solicitations. PR100 concluded that the pricing of resources is assumed to decline from the mainland U.S. to Puerto Rico cost differential seen in Tranche 1 and 2 to a much lower premium, which would then persist to the end of the 2025 IRP planning horizon. The cost trajectory for the mid-to-later years of the 2025 IRP would then follow the ATB cost trajectories with a steady cost premium to reflect the continuing higher costs in Puerto Rico.

Table 66 below presents the utility-scale solar PV costs with and without the application of the PR100 cost scaling factor. It is essential to note that the value ultimately used for the PLEXOS simulation is the cost with the escalation.

Table 66: Utility Scale Solar PV Costs for PLEXOS Modeling

Year	PR100 Cost Scaling Factor	Cost with PR Scaling Factor		
		CAPEX ($/kW)	Fixed O&M ($/kW-yr)	Interconnection ($/kW)
2025	2.25	$1,868	$31.82	$48.88
2026	2.25	$1,739	$30.07	$47.74
2027	2.25	$1,613	$28.34	$46.55
2028	2.16	$1,489	$26.62	$45.31
2029	2.08	$1,367	$24.94	$44.03
2030	1.99	$1,249	$23.28	$42.69
2031	1.91	$1,198	$22.37	$41.30
2032	1.82	$1,145	$21.44	$39.84
2033	1.73	$1,092	$20.49	$38.33
2034	1.65	$1,037	$19.52	$36.76
2035	1.56	$983	$18.53	$35.14
2036	1.48	$982	$18.65	$35.68
2037	1.39	$981	$18.78	$36.25
2038	1.39	$982	$18.94	$36.88
2039	1.39	$984	$19.12	$37.56
2040	1.39	$985	$19.30	$38.27
2041	1.39	$986	$19.48	$38.98
2042	1.39	$987	$19.66	$39.71
2043	1.39	$988	$19.85	$40.45
2044	1.39	$988	$20.03	$41.21

7.3.2 Wind Energy

For the 2025 IRP, LUMA adopted the PR100 estimate, along with a geographic adjustment for utility-scale wind resources in Puerto Rico. This approach is similar to the one used for solar PV.

Table 67 and Table 68 present the onshore and offshore wind energy costs, respectively, with and without the application of the PR100 cost scaling factor. It is important to note that the value ultimately used for the PLEXOS simulation is the cost with escalation.

Table 67: Onshore Wind Costs for PLEXOS Modeling

Year	PR100 Cost Scaling Factor	Cost with PR Scaling Factor		
		CAPEX ($/kW)	Fixed O&M ($/kW-yr)	Interconnection ($/kW)
2025	2.25	$4,414	$107.77	$54.27
2026	2.25	$4,276	$103.10	$53.00
2027	2.25	$4,135	$98.44	$51.68
2028	2.16	$3,991	$93.78	$50.31
2029	2.08	$3,845	$89.13	$48.88
2030	1.99	$3,697	$84.50	$47.40
2031	1.91	$3,576	$81.74	$45.85
2032	1.82	$3,450	$78.86	$44.24
2033	1.73	$3,319	$75.87	$42.56
2034	1.65	$3,183	$72.76	$40.82
2035	1.56	$4,286	$64.34	$39.02
2036	1.48	$4,306	$64.87	$39.62
2037	1.39	$4,329	$65.42	$40.25
2038	1.39	$4,357	$66.08	$40.95
2039	1.39	$4,391	$66.82	$41.71
2040	1.39	$4,425	$67.58	$42.49
2041	1.39	$4,458	$68.33	$43.28
2042	1.39	$4,491	$69.09	$44.09
2043	1.39	$4,524	$69.86	$44.92
2044	1.39	$4,557	$70.63	$45.76

Table 68: Offshore Wind Costs for PLEXOS Modeling

Year	PR100 Cost Scaling Factor	Cost with PR Scaling Factor		
		CAPEX ($/kW)	Fixed O&M ($/kW-yr)	Interconnection ($/kW)
2025	2.25	-	-	-
2026	2.25	-	-	-
2027	2.25	-	-	-
2028	2.16	-	-	-
2029	2.08	-	-	-
2030	1.99	$8,338	$136.25	$20.53
2031	1.91	$7,957	$128.35	$19.85
2032	1.82	$7,571	$120.50	$19.15
2033	1.73	$7,181	$112.73	$18.43

Year	PR100 Cost Scaling Factor	Cost with PR Scaling Factor		
		CAPEX ($/kW)	Fixed O&M ($/kW-yr)	Interconnection ($/kW)
2034	1.65	$6,790	$105.05	$17.67
2035	1.56	$6,398	$97.48	$16.89
2036	1.48	$6,437	$97.88	$17.15
2037	1.39	$6,482	$98.38	$17.43
2038	1.39	$6,540	$99.07	$17.72
2039	1.39	$6,609	$99.91	$18.06
2040	1.39	$6,682	$100.82	$18.39
2041	1.39	$6,757	$101.75	$18.74
2042	1.39	$6,835	$102.72	$19.08
2043	1.39	$6,916	$103.75	$19.45
2044	1.39	$6,999	$104.81	$19.81

7.3.3 Battery Energy Storage Systems (BESS)

LUMA developed the UBESS battery energy storage systems based on the same data sources used by the PR100 data forecast, i.e., NREL 2023 ATB data adjusted with the PR100 cost scaling factor. Table 69 presents the estimated costs.

Table 69: BESS and DBESS Costs for PLEXOS Modeling

	BESS- 2hr		BESS- 4hr		BESS-6hr		DBESS- 8hr	
Year	CAPEX ($/kW)	Fixed O&M ($/kW-yr)	CAPEX ($/kW)	Fixed O&M ($/kW-yr)	CAPEX ($/kW)	Fixed O&M ($/kW-yr)	CAPEX ($/kW)	Fixed O&M ($/kW-yr)
2025	$2,590	$25.07	$4,147	$41.76	$5,704	$58.45	$7,260	$75.13
2026	$2,492	$25.02	$3,964	$41.42	$5,435	$57.82	$6,906	$74.22
2027	$2,393	$24.95	$3,779	$41.03	$5,165	$57.12	$6,551	$73.20

	BESS- 2hr		BESS- 4hr		BESS-6hr		DBESS- 8hr	
2028	$2,293	$24.86	$3,593	$40.60	$4,893	$56.35	$6,193	$72.09
2029	$2,191	$24.76	$3,406	$40.13	$4,621	$55.50	$5,835	$70.87
2030	$2,089	$24.64	$3,218	$39.60	$4,348	$54.57	$5,477	$69.54
2031	$2,015	$24.90	$3,098	$39.97	$4,181	$55.03	$5,264	$70.09
2032	$1,939	$25.17	$2,974	$40.32	$4,009	$55.48	$5,045	$70.63
2033	$1,860	$25.44	$2,847	$40.67	$3,834	$55.91	$4,820	$71.15
2034	$1,778	$25.70	$2,716	$41.02	$3,653	$56.34	$4,591	$71.66
2035	$1,695	$25.96	$2,582	$41.35	$3,469	$56.75	$4,356	$72.14
2036	$1,714	$26.21	$2,606	$41.68	$3,497	$57.14	$4,388	$72.61
2037	$1,734	$26.46	$2,629	$41.99	$3,524	$57.52	$4,419	$73.05
2038	$1,753	$26.71	$2,652	$42.30	$3,550	$57.89	$4,449	$73.48
2039	$1,773	$26.95	$2,674	$42.59	$3,575	$58.24	$4,477	$73.88
2040	$1,792	$27.19	$2,696	$42.88	$3,600	$58.56	$4,504	$74.25
2041	$1,811	$27.42	$2,717	$43.15	$3,623	$58.87	$4,530	$74.60
2042	$1,830	$27.65	$2,738	$43.41	$3,646	$59.16	$4,554	$74.92
2043	$1,848	$27.87	$2,758	$43.65	$3,667	$59.43	$4,576	$75.21
2044	$1,866	$28.08	$2,777	$43.88	$3,687	$59.67	$4,597	$75.47

7.3.4 Thermal Units

LUMA utilized cost estimates provided by the 2025 IRP technical consultant for several thermal units included in the model, specifically the Wärtsilä 18V50DF (1x0), General Electric LM2500 (1x0), General Electric LM6000 (1x0), and Siemens (2x1) SGT-800. To do so, the 2025 IRP technical consultant proposed cost estimates based on their industry experience.

Furthermore, LUMA has adopted costs for certain generic simple cycle gas turbine (GT) and combined cycle gas turbine (CC) units based on the same source used by the PR100 study, namely the NREL 2023 ATB data adjusted with the PR100 cost scaling factor.

The thermal units considered for the development of the 2025 IRP are:

- **Reciprocating internal combustion engine (RICE) units**
  - Wärtsilä 18V50DF 1x0
    - Nameplate capacity: 18 MW
- **Gas turbines (GT)/Simple cycle**
  - General Electric LM2500 1x0
    - Nameplate capacity: 35 MW

- General Electric LM6000 1x0
  - Nameplate capacity: 99.5 MW
- General Electric gas turbine (F-Frame 1x0)
  - Nameplate capacity: 226 MW

- **Combined cycle (CC) units**
  - Siemens 2x1 SGT-800
    - Nameplate capacity: 144 MW
  - NG 1x1 combined cycle (F-Frame)
    - Nameplate capacity: 373 MW
  - NG 1x1 combined cycle (H-Frame)
    - Nameplate capacity: 551 MW

LUMA limited new CC plant additions to either San Juan or Costa Sur due to their existing LNG infrastructure, Sargent & Lundy's 2021 report to FEMA[135] recommending that new CC unit additions to facilities be limited to sites with port access, and a LUMA estimate of the large number of LNG truck delivery that would be required to service a large CC plant operating at typical capacity factors.[136]

The estimated costs are presented in Table 70 (Rice and GT units) and in Table 71 (combined cycle units) below.

Table 70: RICE and Simple Cycle Units

	RICE (18V50DF 1x0)		GT (LM2500 1x0)		GT (LM6000 1x0)		GT (F-Frame 1x0)	
Year	CAPEX ($/kW)	Fixed O&M ($/kW-yr)	CAPEX ($/kW)	Fixed O&M ($/kW-yr)	CAPEX ($/kW)	Fixed O&M ($/kW-yr)	CAPEX ($/kW)	Fixed O&M ($/kW-yr)
2025	$3,481	$51.76	$3,284	$57.04	$3,977	$33.05	$3,374	$27.68
2026	$3,331	$49.54	$3,143	$54.59	$3,806	$31.63	$3,301	$28.26
2027	$3,181	$47.31	$3,002	$52.13	$3,635	$30.21	$3,225	$28.74
2028	$3,032	$45.09	$2,861	$49.68	$3,464	$28.79	$3,145	$29.34
2029	$2,882	$42.86	$2,719	$47.23	$3,293	$27.36	$3,061	$29.84
2030	$2,732	$40.63	$2,578	$44.78	$3,122	$25.94	$2,973	$30.46
2031	$2,583	$38.41	$2,437	$42.32	$2,951	$24.52	$2,881	$30.97
2032	$2,433	$36.18	$2,296	$39.87	$2,780	$23.10	$2,785	$31.62
2033	$2,419	$35.98	$2,283	$39.64	$2,764	$22.97	$2,684	$32.15
2034	$2,419	$35.98	$2,283	$39.64	$2,764	$22.97	$2,579	$32.82

[135135] Sargent & Lundy's 2021 report to FEMA on the feasibility of locating a new CC plant at Palo Seco
[136] See Section 2.03(F)(1)(a) of Regulation 9021

	RICE (18V50DF 1x0)		GT (LM2500 1x0)		GT (LM6000 1x0)		GT (F-Frame 1x0)	
2035	$2,419	$35.98	$2,283	$39.64	$2,764	$22.97	$2,470	$33.36
2036	$2,419	$35.98	$2,283	$39.64	$2,764	$22.97	$2,511	$34.05
2037	$2,419	$35.98	$2,283	$39.64	$2,764	$22.97	$2,553	$34.61
2038	$2,419	$35.98	$2,283	$39.64	$2,764	$22.97	$2,596	$35.33
2039	$2,419	$35.98	$2,283	$39.64	$2,764	$22.97	$2,639	$36.06
2040	$2,419	$35.98	$2,283	$39.64	$2,764	$22.97	$2,683	$36.65
2041	$2,419	$35.98	$2,283	$39.64	$2,764	$22.97	$2,727	$37.41
2042	$2,419	$35.98	$2,283	$39.64	$2,764	$22.97	$2,771	$38.02
2043	$2,419	$35.98	$2,283	$39.64	$2,764	$22.97	$2,816	$38.80
2044	$2,419	$35.98	$2,283	$39.64	$2,764	$22.97	$2,862	$39.42

Table 71: Combined Cycle Units

	CC (2x1 SGT-800)		CC 1x1 Combined Cycle (F-Frame)		CC 1x1 Combined Cycle (H-Frame)	
Year	**CAPEX ($/kW)**	**Fixed O&M ($/kW-yr)**	**CAPEX ($/kW)**	**Fixed O&M ($/kW-yr)**	**CAPEX ($/kW)**	**Fixed O&M ($/kW-yr)**
2025	$3,716	$19.28	$3,517	$36.08	$5,047	$42.00
2026	$3,556	$18.45	$3,432	$36.54	$4,942	$42.72
2027	$3,396	$17.63	$3,343	$37.11	$4,831	$43.45
2028	$3,237	$16.80	$3,251	$37.57	$4,714	$44.18
2029	$3,077	$15.97	$3,155	$38.16	$4,591	$44.93
2030	$2,917	$15.14	$3,055	$38.75	$4,462	$45.81
2031	$2,757	$14.31	$2,951	$39.21	$4,326	$46.58
2032	$2,597	$13.48	$2,844	$39.81	$4,185	$47.36
2033	$2,583	$13.40	$2,733	$40.28	$4,036	$48.15
2034	$2,583	$13.40	$2,618	$40.88	$3,882	$48.95
2035	$2,583	$13.40	$2,499	$41.49	$3,719	$49.76
2036	$2,583	$13.40	$2,540	$42.11	$3,783	$50.73
2037	$2,583	$13.40	$2,581	$42.87	$3,848	$51.56
2038	$2,583	$13.40	$2,622	$43.64	$3,913	$52.40
2039	$2,583	$13.40	$2,665	$44.43	$3,979	$53.41
2040	$2,583	$13.40	$2,707	$45.23	$4,046	$54.28
2041	$2,583	$13.40	$2,750	$45.88	$4,114	$55.15
2042	$2,583	$13.40	$2,794	$46.70	$4,183	$56.04
2043	$2,583	$13.40	$2,838	$47.53	$4,253	$57.11
2044	$2,583	$13.40	$2,883	$48.38	$4,324	$58.02

The high-cost estimates for the thermal energy resource technologies included an additional cost escalator of 1.25 times the costs showcased in Table 70 and Table 71.

7.3.5 Transmission Lines

As part of the resource analysis, LUMA sought to incorporate the capabilities and limitations of the current transmission system into decision-making regarding the location and timing of new energy resource development and the retirement of existing energy resources. To incorporate the transmission system in the resource decisions, LUMA chose to model the Puerto Rico loads and energy resources as eight different geographic regions of the island, which LUMA refers to as transmission planning areas (TPAs). Each TPA includes a portion of the island's load, and each contains whatever generation is currently located within the geographic boundaries of the TPA. The island's transmission system is then represented in the resource model as thirteen different links that interconnect the eight TPAs. LUMA performed transmission system analysis to develop a high-level estimate of the bi-directional transfer capacity of all of the individual transmission lines that contribute to power between the two specific TPAs joined by a specific link. The resource model then monitors the movement of power from energy resources to loads on an hourly basis, including power transfer across transmission links to serve loads.

The load within a TPA can be served by generation within the TPA or by power transfers across the transmission links from neighboring TPAs. When transmission links become congested and impact the ability to serve load, the resource model will choose the most economic choice between:

- Changing the dispatch of available energy resources to serve the load, i.e., changing the dispatchable output of energy resources and transmission paths used to serve the load
- Building generation within the TPA, requiring additional or in another TPA that is connected by an uncongested link to the TPA
- Upgrading the transmission links to increase their transfer capacity
- A combination of the options above

LUMA developed estimates of transmission plan upgrades for thirteen different pathways connecting the eight TPAs. The development of the transmission line cost estimates involved a comprehensive review of data from LUMA, as well as relevant information from the mainland U.S. In developing the transmission line cost estimates, LUMA considered the differential costs between Puerto Rico and the mainland U.S., and the 165 mph wind force standards employed by LUMA to ensure the structural integrity and reliability of the infrastructure.

All capacity assessments for potential transmission upgrades were based on an evaluation of either single- or double-conductor configurations, specifically utilizing the 1192.5 MCM conductor type, and operating voltages of 115 kV and 230 kV. Furthermore, the distance calculations incorporated into these estimates are derived from the assumed distances between substations identified as the end points for the potential transmission upgrades.

The cost and capacity estimates presented below in Table 72 are high-level planning estimates designed to represent average configurations and associated costs linked to actual expenditures. These estimates are characterized by a significant degree of variability, with anticipated fluctuations in actual costs falling within the ranges defined by Class 4 and Class 5 cost estimation categories. Specifically, estimates may vary by approximately -30% to +50% for Class 4 and by -50% to +100% for Class 5.

Table 72: Transmission Lines Cost Estimates to be Used in the Puerto Rico 2025 IRP Modeling

#	Area 1	Area 2	Distance between Main Substation Connections (Miles)	115kV Double 1192.5 MCM Conductor, Single Circuit ($/mi)	115kV Double 1192.5 MCM Conductor, Double Circuit ($/mi)	115 kV Upgrades Costs $/MW /mi	230kV Single 1192.5 MCM Conductor, Single Circuit ($/mi)	230kV Double 1192.5 MCM Conductor, Single Circuit ($/mi)	230 kV Upgrades Costs $/MW /mi
[redacted]									

Table 72 shows that for each transmission link, the 230 kV alternative resulted in the lowest cost based on $/MW/mile. Based on these results and considering that the PLEXOS modeling only accounts for the cost and capacity of the upgrades (the operating voltage is not factored into the PLEXOS assessment of options), only the 230 kV options for the transmission line upgrades were utilized in the PLEXOS modeling.

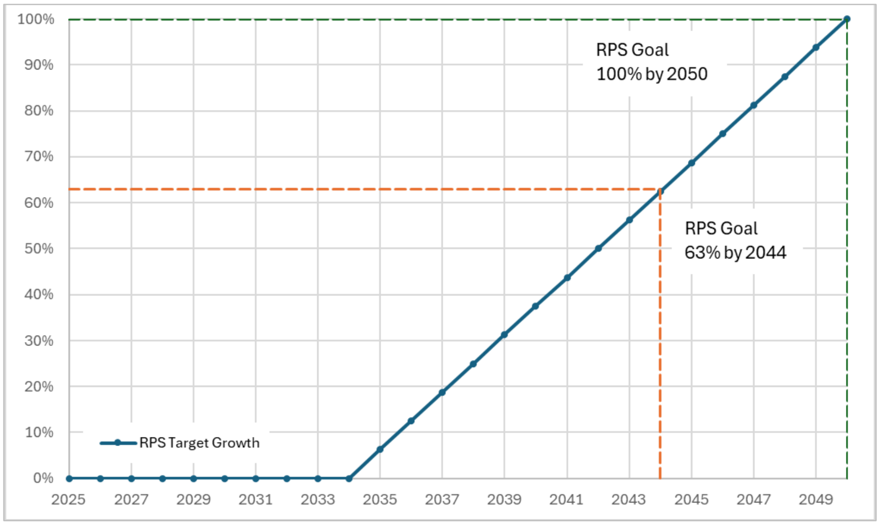
7.3.6 Renewable Portfolio Standard

Initially, the Puerto Rico Energy Policy Act (Act 82) established an RPS with interim goals of 40% of generation from renewable sources by 2025, 60% by 2040, and 100% by 2050. However, with the enactment of Act 1-2025, these interim goals were eliminated, maintaining only the final goal of achieving 100% renewable electricity generation by 2050.

Act 1-2025 establishes that this goal must be achieved in an orderly and progressive manner, to the extent that available technologies allow, without compromising the reliability, stability, or continuity of the electric system. It also highlights the need to reduce the use of fossil fuels, while guaranteeing a reasonable cost for the electric system and maximizing the use of renewable resources in the short, medium, and long term. Act 1-2025 reflects a more flexible approach to energy transition, focused on the technological and operational viability of Puerto Rico's electric system.

To consider Act 1-2025's RPS target in the 2025 IRP PLEXOS modeling, LUMA included a "soft" RPS target starting in 2035, progressing linearly to achieve 100% RPS by 2050. As such, LUMA is considering a 66.7% RPS goal by 2044, represented in Figure 64.

Figure 64: RPS Targets (Act 1-2025)



7.3.7 Scenario Development

The development of a robust 2025 IRP that allows long-term energy planning for Puerto Rico requires the evaluation of a set of scenarios that go beyond a single, most-likely set of forecasts and assumptions (base case). The base case serves as the foundational planning scenario, built using the most likely conditions for the various factors considered under the 2025 IRP, including load growth, distributed energy deployment, and fuel prices. However, LUMA tested the energy resource options against a diverse range of alternative futures, such as different customer load and generation cost trajectories, to assess the robustness of the options and ensure that the Preferred Resource Plan (PRP) ultimately recommended has the flexibility to perform well under a range of future conditions.

Puerto Rico's electric system is uniquely vulnerable to external shocks due to its insular nature, limited generation diversity, aging infrastructure, and exposure to extreme weather events, such as high temperatures and hurricanes. Additionally, the ongoing energy transition driven by the retirement of unreliable legacy fossil-fueled generation, and the desire to increase renewable energy generation, introduces further uncertainty to the electric system's future development. These dynamics underscore the importance of scenario-based planning. This is particularly critical in Puerto Rico, where policy, financing, and implementation timelines are evolving, and where community needs and infrastructure constraints must be balanced thoughtfully.

Ultimately, the use of multiple scenarios strengthens the integrity of the 2025 IRP by ensuring it reflects not only the most likely assumptions and forecasts, but also others that have been examined through an assessment of uncertainties. This approach enhances the value of the 2025 IRP as a tool for guiding strategic decisions that are more cost-effective, resilient and adaptable over the long term.

Development of Scenarios

As part of the 2025 IRP development process, LUMA led a comprehensive engagement effort to ensure that the different scenarios reflected the priorities, concerns, and expectations of a broad range of stakeholders. To do so, a total of 17 workshops were organized to gather input and recommendations from stakeholders, including government agencies, industry experts, community representatives, and advocacy groups. These collaborative sessions provided valuable insights that helped guide the scenario planning process. LUMA then worked with the Energy Bureau's technical consultant on refinements and modifications, and on May 13, 2025, the Energy Bureau issued an R&O defining 12 Primary (or Core) and five supplemental scenarios to be analyzed in this IRP. The required scenarios are detailed in Table 73 and Table 74.

Table 73: May 13th, 2025, Core Scenarios

Scenario	Scenario Name	Load Forecast	Solar and Battery Capital Costs	Gas Plant Capital Costs (CCs and GTs)	Level of DBESS Control	Natural Gas Fuel Cost	Include Biodiesel as Selectable Option	Fixed Resource Decisions
1	Base Assumptions for all variables	Base	Base	Base	Base	Base	Yes	Base
2	High load (peakier/ low LF) with base assumptions for other variables	High	Base	Base	Base	Base	Yes	Base
3	Base load with high fossil capital costs	Base	Base	High	Base	Base	Yes	Base
4	Base load with low renewable energy capital costs and high fossil capital costs	Base	Low	High	Base	Base	Yes	Base
5	Base load with high gas fuel costs	Base	Base	Base	Base	High	Yes	Base
6	Base load with high gas fuel costs and high gas capital costs	Base	Base	High	Base	High	Yes	Base
7	Flex Run of Core B (2) run under Scenario 1 conditions	Base	Base	Base	Base	Base	Yes	Base
8	Flex Run Core Resource Plan A (1) runs under Scenario 2 conditions	High	Base	Base	Base	Base	Yes	Base
9	Flex run of either Core A or B under low load conditions	Low	Base	Base	Base	Base	Yes	Base
10	Flex Run Core Resource Plan A (1) runs under High Cost & High Load Conditions	High	High	Base	Base	Base	Yes	Base
11	Flex Run Core B (2) runs under High Cost and High Load Conditions	High	High	Base	Base	Base	Yes	Base
12	Biodiesel is unavailable/ too costly on the island	Base	Base	Base	Base	Base	No	Base

Table 74: May 13, 2025, Supplemental Scenarios

Scenario	Scenario Name	Load Forecast	Solar and battery capital costs	Gas plant capital costs (CCs and GTs)	Level of DBESS control	Natural gas fuel cost	Include biodiesel as selectable option	Hard Coded Resources
13	High DBESS control with base assumptions for other variables	Base	Base	Base	High	Base	Yes	Base
14	No NGCC 460 MW San Juan	Base	Base	Base	Base	Base	Yes	No NGCC
15	Marine Cable	Base	Base	Base	Base	Base	Yes	Base
16	Alternative RPS 1	Base	Base	Base	Base	Base	Yes	Base
17	Alternative RPS 2	Base	Base	Base	Base	Base	Yes	Base

Scenario assumptions required by the Energy Bureau's May 13th R&O[137] include:

- Constant trajectory of distributed solar photovoltaic (DPV) installations for all scenarios
- Identical trajectory of heavy fuel oil costs and diesel costs for all scenarios
- Identical trajectory of fixed decision additions and retirements for all scenarios except scenario 14 as noted
- RPS soft target beginning 2035 and ramping to 100% by 2050 for all scenarios except scenarios 16 and 17
- Alternative RPS1 = RPS soft target beginning 2025 and ramping to 100% by 2050
- Alternative RPS2 = no RPS soft target at all until very late in the planning horizon, starting in 2044 and ramping to 100% by 2050
- All scenarios will use a separate resource option to reflect ASAP Phase 2 BESS at a lower cost than the BESS low-cost assumption
- All scenarios assume Aguirre ST 1 and 2 are out of service, and 800 MW of temporary generation is in service, starting in 2025
- Solar PV and BESS costs are separate variables in the modeling: "base" and "low" capital costs seen here apply to each

[137] See at: https://energia.pr.gov/wp-content/uploads/sites/7/2025/05/20250513-AP20230004-Resolution-and-Order.pdf

7.3.8 Base Case Scenario

Scenario 1 is also viewed as the base case, representing LUMA's view of the most likely assumptions and forecast or median probability outcome. This scenario reflects the most likely assumptions and forecasts over the planning horizon, based on current policies, known resource additions, economic and demographic projections, and fuel price forecasts, among many others.

As such, the base case incorporates existing system constraints, planned infrastructure investments, and regulatory requirements, providing a realistic representation of future energy demand and supply under a "business-as-usual" trajectory. This scenario assists in projecting how the system is expected to evolve without significant deviations or policy shifts, providing a critical benchmark of comparison against alternative scenarios.

7.4 Modeling Assumptions for Existing Generation

7.4.1 Retirement dates

The only planned retirements for the development of the modeling for the 2025 IRP are AES 1 and 2 units in 2032, due to Act 1-2025 legislation, and units whose contracts are expiring. Please refer to Section 2 Planning Environment for more detail about these units.

As is typical with baseline assumptions, for all scenarios in the 2025 IRP (except for the AES units) IPP plants are assumed to cease their energy contributions at the expiration of their respective contracts. However, LUMA has considered several retirement dates of units as modeling assumptions for the purpose of the 2025 IRP development in the PLEXOS modeling.

- **Aguirre ST 1 & 2:** Assumed to be out of service from the beginning of the IRP throughout the full IRP planning period (2025 to 2044), as both of these units were on major unplanned outages early in 2025 when the resource modeling assumptions were being discussed for the 2025 IRP. This was agreed between LUMA and the Energy Bureau and was then documented in the Energy Bureau R&O of May 13, 2025.

- **Heavy Fuel Oil (HFO) units:** The Energy Bureau expressed the desire to retire PREPA units that use HFO as its main fuel (Aguirre ST 1 & 2, Palo Seco 3 & 4 and San Juan 7 & 8) as soon as their capacity could be replaced due to their age, reliability, performance and emissions. To address this, LUMA established a window between 2030 and 2034 in which all six HFO units should be retired. The 2030 earliest date of retirement was selected as it was the first year when new firm capacity could be built and operated. In addition, the 2034-date was chosen as it allowed a 5-year window within which the resource modeling software could select a preferred retirement date based on the cost and reliability criteria established for all additions and retirements.

- **EcoEléctrica:** While EcoEléctrica contract expires in 2032, LUMA assumed this contract would be extended to enable this unit to remain in operation throughout the full IRP planning period (2025 to 2044). This expectation was shared with EcoEléctrica (the generator) during meetings and in the SETPR process with no opposition. LUMA judged the assumption of its extended operation to be reasonable, given EcoEléctrica's historical performance and efficiency.

7.4.2 Compliance with regulatory and legal requirements

PREPA, along with the independent power producers (IPPs), will be responsible for ensuring compliance with the existing permits. Given the urgent need for reliable capacity in Puerto Rico, LUMA assumes that the owners and operators of the legacy units will maintain their operational status through the dates specified in the preferred resource plan (PRP).

Furthermore, no capital or operating costs have been included beyond the estimated FOM and VOM expenses necessary to comply with regulatory requirements. Additionally, there are no capital or operating costs accounted for beyond the estimated FOM and VOM to extend the lifespan of the legacy units.

Lastly, for legacy units converted to biodiesel operation during the planning period, LUMA has estimated the associated fuel conversion costs as an additional capital expenditure.

7.4.3 Updates on generation resources

Since the approval of the 2020 IRP, several changes to the resources have been made. These are discussed in Appendix 2 Prior Action Plan Implementation Status.

LUMA is also assuming that at least 60% of all generation resources, operated by PREPA or IPPs, must comply with the “high efficiency” generation requirement in accordance with Section 6.29 (a) of Act 57.

According to this definition, generation is considered “highly efficient” if meets the following two requirements[138]:

1. **Cost requirement:** The yearly unit total cost for electricity generation cannot exceed $100/MWh (i.e., $0.10/kWh) adjusted to 2018 dollars
2. **Emissions requirement:** The average annual rate of carbon emissions from generating units is lower than the United States nationwide average for plants with the same primary fuel generation as reported in the U.S. Environmental Protection Agency (EPA) Emissions and Generating Resource Integrated Database (eGRID).

Table 75: Emission limits for high-efficient fossil fuel generation[139]

Fuel Type	Average annual rate of CO2 emissions (lbs/MWh)
Coal	2,187
Residual Fuel Oil	1,930
Diesel Fuel	2,681
Natural Gas	1,433

[138] Puerto Rico Energy Bureau. (2020). Proposed Definition for the Term "Highly Efficient Fossil Generation". (CEPR-MI-2016-0001, November 6)

[139] Source: “egrid2018_data_v2.xlsx”, Tab “PLNT18”, Column “BA”, “Plant annual CO2 total output emission rate (lb/MWh)”, available at https://www.epa.gov/egrid/historical-egrid-data

Section 8: Resource Plan Development

8.0 Resource Plan Development

As noted above, in accordance with Regulation 9021, the May 13th R&O, and Puerto Rico's energy public policy, LUMA developed 12 Core scenarios to evaluate a range of potential pathways for meeting Puerto Rico's future electricity needs and to support a transparent, well-informed selection of the Preferred Resource Plan (PRP). This section provides a comprehensive description of the mechanism used by LUMA in developing resource plans, including LUMA's extensive stakeholder engagement efforts to better understand customers' concerns about the current condition of the electric system and their recommendations for how to improve the electric grid of Puerto Rico. In collaboration with the Energy Bureau and its technical consultant, LUMA identified key inputs and assumptions for the development of the scenarios, ensuring alignment with Puerto Rico's public energy policy, industry best practices, and incorporating all existing and in-development energy projects, as well as load projections.

Each Core Scenario was modeled using the energy modeling software PLEXOS®, and a complex series of Long Term (LT) and Short Term (ST) iterations, enabling LUMA to identify cost-effective and reliable resource plans under a range of real and likely future conditions. LUMA then compared each resource plan against the Core Scenarios to select the PRP that could satisfy customers' energy and capacity requirements at the least cost. Below, LUMA describes the methodology and the criteria used to select the PRP. The PRP is a planning tool intended to guide the government and energy providers in developing Puerto Rico's electric system. LUMA will update the PRP every three years to reflect new technologies and changes affecting the electric system.

8.1 Solutions for the Energy Transformation of Puerto Rico (SETPR)

Since the beginning of 2022, LUMA has been working cooperatively and diligently to develop a realistic and pragmatic IRP that reflects industry standards and the diverse perspectives of stakeholders from across the Island. The 2025 IRP is built on accurate and comprehensive data and analyses, and reflects Puerto Rico's future energy needs and priorities as it moves toward a more reliable, more resilient, and cleaner energy system.

In developing the 2025 IRP, LUMA has prioritized stakeholder engagement through a collaborative process referred to as the Solutions for the Energy Transformation of Puerto Rico (SETPR) initiative. As required by the Puerto Rico Energy Bureau (Energy Bureau), this collaborative process was designed to engage with a broad variety of stakeholders to gain their input regarding Puerto Rico's energy future.

In October 2023, LUMA launched the First Round of SETPR Meetings to gather input from stakeholders through in-person and virtual meetings and a public website. By January 2025, LUMA had successfully held three out of four planned SETPR Meeting Rounds. With a total of 32 separate workshops, the initiative garnered input from 223 participants representing private companies, government, social interest groups, commercial and professional associations, and the energy sector in general.

SETPR Stakeholder Meeting Rounds were held as follows:

- **First Round:** October 10 through November 17, 2023
- **Second Round:** January 15 through February 8, 2024
- **Third Round:** January 14 through January 17, 2025

- **Fourth Round:** October 7 through October 9, 2025

8.1.1 First Round of Stakeholder Meetings

LUMA engaged with relevant stakeholders through multiple channels, including (1) a customer flyer, (2) the SETPR website, (3) an online survey, and (4) 17 public workshop events to gather direct feedback from the public on the most important objectives and categories the IRP should focus on. The SETPR First Round of Stakeholder Meetings had a total of 140 participants. The registered attendees represented the following sectors: private companies (50), government (38), social interest groups (22), commercial and professional associations (12), individuals (12), generators (3), and students (3). Table 76 shows in detail the date and times of each workshop session.

Table 76: First Round of SETPR Meetings Schedule

Modality	Date	Location	Time
In-Person	Tuesday, October 10, 2023	CAPR San Juan	8:30 am – 12:00 pm
In-Person	Tuesday, October 10, 2023	CAPR San Juan	1:30 pm – 4:30 pm
In-Person	Wednesday, October 11, 2023	CAPR San Juan	8:30 am – 12:00 pm
In-Person	Wednesday, October 11, 2023	CAPR San Juan	1:30 pm – 4:30 pm
In-Person	Thursday, October 12, 2023	CAPR San Juan	8:30 am – 12:00 pm
In-Person	Thursday, October 12, 2023	CAPR San Juan	1:30 pm – 4:30 pm
In-Person	Wednesday, October 18, 2023	Iglesia Cristiana Discípulos de Cristo	2:30 pm – 5:30 pm
In-Person	Thursday, October 19, 2023	Escuela Julio Lebrón Soto Castañer	2:30 pm – 5:30 pm
In-Person	Tuesday, October 24, 2023	MAPR San Juan*	1:30 pm – 4:30 pm
In-Person	Thursday, October 26, 2023	Humacao**	1:30 pm – 4:30 pm
In-Person	Wednesday, November 1, 2023	Guayama	1:00 pm – 4:00 pm
In-Person	Thursday, November 2, 2023	Ponce	1:00 pm – 4:00 pm
In-Person	Friday, November 3, 2023	Arecibo	1:00 pm – 4:00 pm
In-Person	Wednesday, November 8, 2023	SESA PR Conference - Fairmont Hotel San Juan	All day event
In-Person	Thursday, November 9, 2023	Mayagüez	1:00 pm – 4:00 pm
Virtual	Thursday, November 16, 2023	Zoom	9:00 am – 12:00 pm
Virtual	Friday, November 17, 2023	Zoom**	9:00 am – 12:00 pm

*Canceled.
**No participants showed.

LUMA worked with an external moderator to conduct the workshops. LUMA oversaw the registration, presentation, workshops, and answered questions from stakeholders throughout the meetings. All workshops included (1) an introductory safety message, (2) a short IRP presentation (15-20 minutes) explaining the requirements and objectives of the meeting and the SETPR initiative, and (3) objectives and scenarios exercise (1 hour). During the exercise, stakeholders were encouraged to submit their preferred objectives and scenarios based on five categories: Costs, Distributed Generation, Environment, Reliability and Resilience, or Other.

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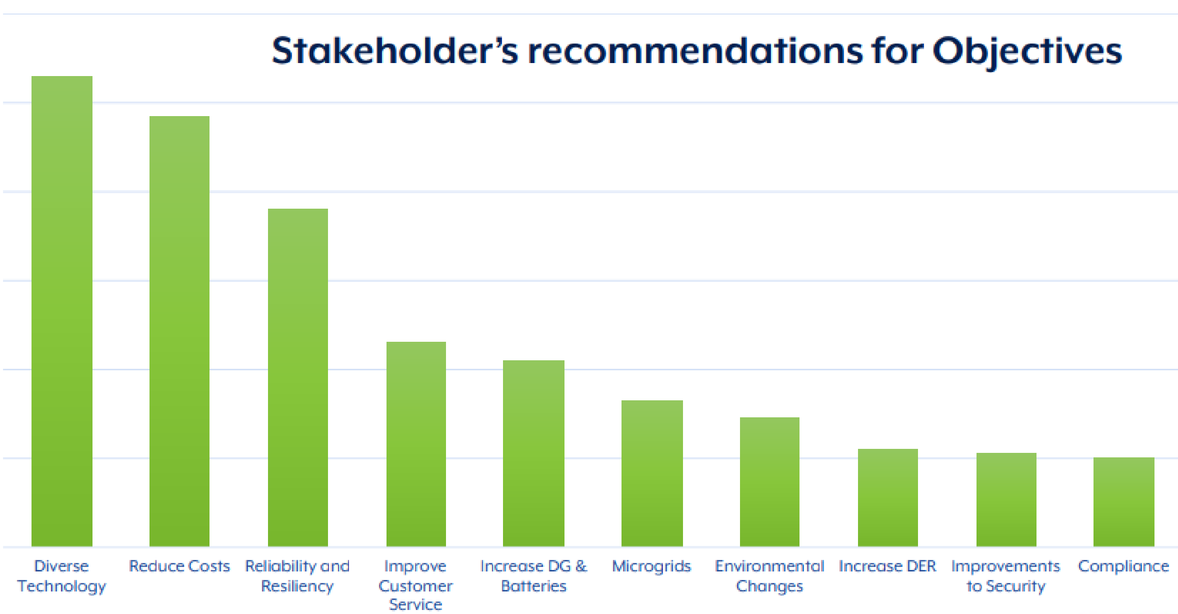
Once all objectives were submitted, stakeholders voted on their preferred five objectives during the group activity, and the results were tallied. Stakeholder groups did not vote on scenarios. However, participants were encouraged to visit the SETPR website for additional updates and to participate in the next round of meetings. It was established that LUMA would present the IRP's selected objectives and scenarios during the Second Round of Meetings.

Based on the data collected from participants across all workshops, the five most common objectives among stakeholders are ranked in order as follows:

- **Diversity of Generation Technologies:** Stakeholders want a diverse resource plan of generation technologies for clean and renewable energy, from hydroelectric to nuclear, not just solar.
- **Reduction of Costs:** Stakeholders would like generation costs and rates to be reduced**.**
- **System Resilience and Reliability:** Stakeholders want fewer outages and outages of shorter duration.
- **Increase of Distributed Generation and Batteries:** Stakeholders want to see more distributed generation and batteries in compliance with Act 17.
- **Improvement of Customer Service**: Stakeholders want increased and robust communication channels from LUMA.

The most common objectives were identified by tallying the votes submitted by stakeholders throughout all 17 workshop sessions of the First Round of SETPR Meetings. Figure 65 shows in detail the amount of stakeholder votes per objective.

Figure 65: Total of Votes per Objective Subcategory



Stakeholder votes on objectives were simple to categorize, especially since there was a consensus of priorities for Puerto Rico's energy future. To determine which would be the most likely scenarios after the discussion, LUMA needed to investigate further how stakeholders perceived certain aspects within the energy planning process. To that end, LUMA asked for and stakeholders provided their feedback about possible generation resources and objectives, and LUMA grouped them into categories. The categories were:

- Agriculture – Zoned Land for Renewables
- Climate Change
- Environmental Impact
- Cost of Renewables
- Economic Conditions
- Load Growth
- Others

The feedback provided by stakeholders varied. For example, in the Agriculture - Zoned Land for Renewables category, most stakeholders expressed strong opposition to utilizing agricultural land for the development of renewable energy projects. Some stakeholders agreed to development in agricultura land only in sites that are not in use, if it followed PR100 and DOE guidelines; or if it was less than 5% of all agricultural land. Some stakeholders favored the use of agricultural land only for solar, and others exclusively for wind turbines. Some stated they would agree to agricultural land use only if these had already been environmentally impacted or in the case of used brownfields.

Regarding Climate Change, stakeholders gave this category a High level of priority in terms of building an electric system that is resilient and able to withstand climate change. In the Environmental Impact category, some gave it a High level of priority while others considered it of Low priority.

For the Cost of Renewables, LUMA presented stakeholders with 12 scenarios in which the costs and strategies varied. Some agreed that, while renewable energy is cleaner, it is never cheaper or reliable. Others agreed that a strategic course of action would be to prepare the landscape for new generation technologies that are less expensive, for example, onshore and offshore wind. Several stakeholders considered a good option was long-lasting batteries and to compare their maximum and minimum projected costs. Stakeholders considered that renewable energy represented high costs. Others considered they should be economically viable and accessible to low-income individuals. However, it was also brought up that maintenance costs for rooftop PVS and BESS are too high for low-income households. Stakeholders agreed that obtaining more efficiency from renewables will compensate for their high costs, while others considered that energy storage system costs will not decrease, judging by what is currently being projected. A scenario for revitalizing hydroelectric power plants was favored since stakeholders considered this technology impacts population, economic growth, and costs.

In a related topic, stakeholders agreed that incentives and subsidies cause rate impacts and that therefore, they should be eliminated. In the Population category, most scenarios projected a declining population, and therefore, low load growth. One scenario projected a growing economy and an increasing load growth. In the Economic Conditions category, stakeholders agreed economic and energy transformation must go together, the cost of doing business in Puerto Rico should be assessed, and that the IRP should model economic conditions with an energy rate of over 20 cents per kWh. Stakeholders also argued that the Puerto Rican economy is changing due to an increase in entrepreneurship tendencies.

LUMA grouped Load Growth into its own category, and stakeholders were able to provide feedback. The stakeholders contemplated that (1) load growth would be high, (2) population is moving to metropolitan areas, (3) behavior could be assessed by customer meter instead of by population, (4) projections should contemplate actual demand and renewable energy systems' capacity and that (5) load forecast will be impacted by EV growth.

Stakeholders also expressed interest in: (1) an expansion of EV infrastructure, (2) high PV and DER control, (3) replacing the fossil fuel economy with "the electrification of everything", and (4) the development of a smart grid. In the Others category, stakeholders favored improving streetlight posts by building new ones using concrete. They also brought up topics such as health and safety issues resulting from power outages and expressed favor for more stakeholder participation in government public affairs.

Stakeholders agreed that more microgrids were needed for the central region of Puerto Rico and community centers, and that distributed solar would be beneficial to farms. While some thought that distributed energy would slow or come to a halt, others thought that it would continue to grow and that the integration of distributed solar would also increase. Among other factors to consider, stakeholders agreed that (1) the cost of distributed generation versus centralized needs to be assessed, (2) for Tranches, it is important to consider the time and capacity it takes to integrate renewable energy, and (3) there should be private investment going into renewable energy generation.

8.1.2 Second Round of Stakeholder Meetings

The SETPR Second Round of Stakeholder Meetings, held shortly after the First Round, took place between January and February 2024. The purpose of this round was to present the selected objectives and scenarios of the 2025 IRP. Stakeholder input from the First Round helped identify key characteristics that LUMA used to populate the inputs for proposed scenarios. Based on the feedback received and a thorough internal analysis, LUMA identified and selected eight planning scenarios and 11 key scenario characteristics to be used in the IRP modeling framework. [140]This approach ensured that the scenarios developed were both technically robust and aligned with the diverse perspectives of the stakeholders. Table 77 displays the scenarios and characteristics resulting from stakeholders' feedback.

Table 77: Identified Scenarios and Characteristics

Scenario Name	Characteristics
1. Base	1. Load growth
2. Plentiful Biodiesel at the Cost of Diesel	2. PV Costs
3. High-Distributed Solar and Storage Growth	3. DER Growth
4. Accelerated Load Loss	4. % Distributed Storage Control

[140] The scenarios selected with the feedback of Stakeholders back in February 2024 are not the Primary Scenarios model in the 2025 IRP. These scenarios were later revised, as requested by the Energy Bureau, and submitted on March 11, 2024. See at: https://energia.pr.gov/wp-content/uploads/sites/7/2024/03/20240311-AP20230004-Motion-Submitting-Revised-2024-Integrated-Resource-Plan-Scenarios-and-Characteristics.pdf. The Energy Bureau approved the revised core and supplemental scenarios on March 13, 2024. See at https://energia.pr.gov/wp-content/uploads/sites/7/2024/03/20240313-AP20230004-Resolution-and-Order.pdf. The Primary Scenarios modeled and considered in the 2025 IRP were approved by the Energy Bureau on May 13, 2025 to comply with Act 1-2025. See at: https://energia.pr.gov/wp-content/uploads/sites/7/2025/05/20250513-AP20230004-Resolution-and-Order.pdf

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Scenario Name	Characteristics
5. Optimistic Load Growth and Costs 6. Less Ag. Land Use 7. Compliance with Act 17 EE 8. Marine Cable	5. Storage Costs 6. New Natural Gas Units Allowed 7. Fossil Fuel Costs 8. Biofuel Fuel Costs 9. EV Growth 10. EE Forecast 11. Land Use

For the Second Round, five meetings were held and LUMA gained the input from 33 participants: 14 representing the private sector, one from government, three from social interest groups, six from professional and commercial associations, five individuals, and four generators. Ten were repeat attendees and 23 were first-time participants. Table 78 shows in detail the dates and times for each session.

Table 78: Second Round of SETPR Meetings Schedule

Modality	Date	Location	Time
In-Person	Monday, January 15, 2024	Arecibo	9:30 am – 12:30 pm
In-Person	Tuesday, January 16, 2024	Guayama	9:30 am – 12:30 pm
In-Person	Wednesday, January 17, 2024	San Juan	9:00 am – 12:30 pm
In-Person	Thursday, January 18, 2024	Mayagüez	10:00 am – 1:00 pm
Virtual	Thursday, February 8, 2024	Zoom	10:00 am – 12:00 pm

8.1.3 Third Round of Stakeholder Meetings

From January 14 until January 17, 2025, LUMA hosted a total of five meetings to present the Preliminary Resource Plans A through D resulting from Scenarios 1 to 4, consisting of three in-person sessions at the Colegio de Ingenieros y Agrimensores de Puerto Rico (CIAPR, in Spanish) in San Juan and Ponce, and two virtual sessions. These meetings counted towards Continuing Education Credits (CEC) with the CIAPR. Participants who met the required attendance received three hours of CECs for license maintenance under CIAPR regulation. Table 79 shows in detail the dates and times for each session of the Third Round of meetings.

Table 79: Third Round of SETPR Meetings Schedule

Modality	Date	Location	Time
In-Person	Tuesday, January 14, 2025	CIAPR San Juan	9:00 am – 12:00 pm
In-Person	Tuesday, January 14, 2025	CIAPR San Juan	1:30 pm – 4:30 pm
In-Person	Wednesday, January 15, 2025	CIAPR Ponce	9:30 am – 12:00 pm
Virtual	Thursday, January 16, 2025	Zoom	9:00 am – 12:30 pm
Virtual	Friday, January 17, 2025	Zoom	9:00 am – 12:30 pm

As with previous stakeholder meetings, SETPR's Third Round had strong participation from a diverse range of industries and community sectors. These meetings fostered meaningful discussion and valuable insights for both the participants and LUMA. A total of 51 stakeholders participated in the Third Round of Meetings: two from government, 18 from the nonprofit and non-governmental sector, 15 from the private sector, and two generators. In this round, more than one person from a specific entity attended the meetings, therefore the number of attendees is higher than the number of entities registered.

During the Third Round of SETPR meetings, LUMA provided an overview of the 2025 IRP development and legal requirements. LUMA also included a technical section, explaining the preliminary Resource Plans A to D resulting from the assumptions of scenarios 1 to 4. The team answered questions and concerns from participants. LUMA informed participants that a Fourth and Final Round of Meetings will be held before the 2025 IRP Report is filed with the Energy Bureau.

LUMA also encouraged stakeholders to participate as intervenors in the adjudicative process once the 2025 IRP is filed and provided information on the time constraint to submit the request to intervene before the Energy Bureau. LUMA considers active stakeholder participation fundamental during the 2025 IRP development process to ensure transparency, regulatory compliance, and alignment with energy public policy objectives.

Table 80 shows the main concerns presented by stakeholders regarding the assumptions in the 2025 IRP modeling, categorized by topic.

Table 80: SETPR Stakeholder Feedback by Topic

Topics	Comments
Modeling Assumptions	**Stakeholders raised concerns regarding the assumptions in the IRP modeling.**
Technologies Selection	• Exclusion of Municipal waste energy, nuclear power, and Offshore wind generation. • Role of Biodiesel as a primary fuel source • Consideration of Landfill Energy Recovery and Virtual Power Plants. • Net Metering and its role in the IRP • Impact of the PR100 assumptions • Energy efficiency projections
Scenario Development	• The stakeholders questioned the rationale behind different scenarios and Resource Plans, including: • Justification of Scenario 1 • Why was the Preliminary Base Case scenario (Scenario 1) chosen as the most likely outcome? • Inclusion of a High-load stress scenario • Methodology and Resource Selection • Main driver of the resource selection in Resource Plans • Levelized Cost of Energy increases over time
Biofuel conversion timing	• Project Implementation and Timeline Concerns • Stakeholders raised concerns about the inclusion of these projects in the IRP
Major Energy Projects	• Tranche 1 and Tranche 2 • 450 MW San Juan plant (P3A) • How Fixed Decisions1 are factored into the scenarios • Funding of Department of Housing programs and subsidized customer projects • Government policies and funding delays • Could impact energy project timelines, delaying project execution

Topics	Comments
Modeling Assumptions	**Stakeholders raised concerns regarding the assumptions in the IRP modeling.**
Transmission and Distribution (T&D) Infrastructure	• Stakeholders inquired about the transmission planning, grid congestion, upgrading of the T&D system, energy quality considerations, and the integration of Distributed Energy Resources (DER).
T&D Planning Considerations	• Why are Transmission Planning Areas (TPAs) aligned with senatorial districts? • Concerns regarding the transmission and distribution congestion • Unclear Timeline of the transmission system upgrades • Whether energy quality requirements are considered for industrial vs residential customers • Support on distributed energy resources
Energy Security and Fuel Dependency	• Stakeholders addressed Puerto Rico's reliance on imported fuels such as biodiesel and LNG. • Concerns about the stability of biodiesel and LNG imports
Distributed Solar Self-consumption	• Is behind-the-meter solar included in long-term planning?
Comparison with other jurisdictions	• How does the Puerto Rico energy landscape compare to Hawaii?
Financial and Cost Considerations	Cost differences between standard diesel and Biofuel • Differences in Solar Energy cost in PR vs. mainland US • Higher solar installation costs in PR compared to other locations • Impact of PREPA's Bankruptcy • Discount Rates in financial models • Implementation of prior IRP recommendations • Concerns about whether previous IRP initiatives were successfully implemented

8.1.4 Fourth Round of Stakeholder Meetings

The Fourth Round of SETPR Stakeholder Meetings was originally scheduled to take place between late April and early May of 2025. These meetings were rescheduled and held from October 7 until October 9, 2025, since the Energy Bureau granted a stay to the May 16 filing of the Final 2025 IRP Report on April 30, 2025. This R&O allowed the 2025 IRP Report to incorporate recent energy policy changes required by the enactment of Act 1-2025[141] and other changes on the generation landscape that significantly shift the original modeled environment. Some of the significant changes are:

- Removal of interim goal of RPS in Act 17-2010
- Contract extension for AES coal generation until 2032
- Addition of 800MW of temporary emergency generation
- Aguirre 1 & 2 assumed to be out of service for the full 2025 IRP planning period (2025 to 2049)

During the Fourth Round of SETPR meeting LUMA presented the PRP to stakeholders.

[141] See at https://sutra.oslpr.org/SutraFiles/anejos/153232/A-1-2025.pdf

8.2 Resource Plan Development Methodology

8.2.1 Methodology Overview

The modeling and analysis conducted to develop the 2025 IRP complies with the requirements in Regulation 9021. LUMA's methodology serves to:

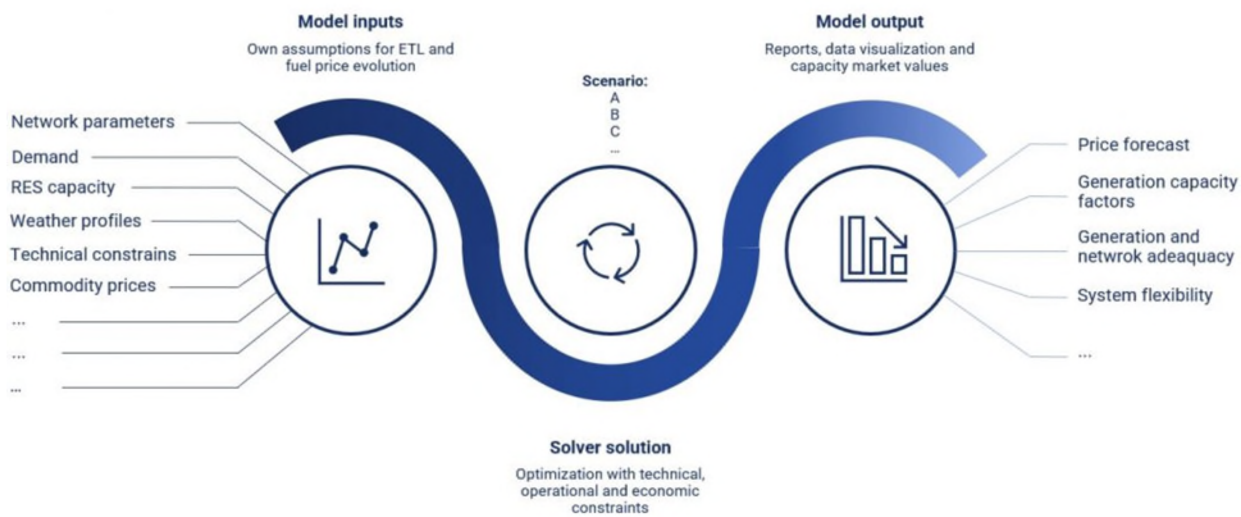
- Incorporate the input and feedback from a broad group of stakeholders through structured workshops held during multiple stages of the development process
- Optimize PVRR over the 2025 to 2044 Planning Period. LUMA employed a resource planning model developed to formulate least-cost resource plans that effectively addressed forecasted customer needs and improved reliability under a range of future scenarios which include varying load forecast, supply costs, fuel cost and fuel availability. All the candidate least cost resource plans move supply resource plans toward the target of 100% renewable by 2050
- Consider demand side resources as fundamental elements of the resource supply planning and dispatch, including progressively increasing contributions from customer EE programs, DR programs, DPV, controlled DBESS, and CHP resources.
- Includes anticipated utility borne costs of adding new energy resources to the system.
- Includes the cost and reliability assessment of retirement of existing resources in developing the least cost resource plan options.
- Incorporates a robust flexibility analysis and additional sensitivity analyses that together provide a modeling and analysis construct that fulfills the need to be both rigorous and comprehensive in the development and ranking of resource plans.

To develop the Puerto Rico 2025 IRP, LUMA used PLEXOS® as the primary modeling tool to define candidate resource plans for different IRP Scenarios. PLEXOS® is a standard energy industry modeling tool used by utilities, regulators, and stakeholders to analyze energy markets. PLEXOS® is a versatile tool capable of:

- Analyzing generation options under user-defined scenarios
- Determining optimal capacity expansion plans in the long-term (LT module), as well as detailed generation dispatch, including contributions from intermittent renewables (ST module).
- Detailed chronological modeling of the power system (load, grid, generation: thermal, renewables, hydro, storage).
- Analyzing an electric system over varying time frame (from days to decades)

PLEXOS® takes all the inputs to the electric model such as system electric demand, minimum reserves requirements, as well as all the generator characteristics, generator costs, fuel costs, etc. and uses these inputs to develop linear equations to represent the system. It then attempts to solve these equations simultaneously such that all the system requirements are met at the lowest cost. Figure 66 provides a simplified illustration of the PLEXOS process flow.

Figure 66: PLEXOS Process Flow Overview

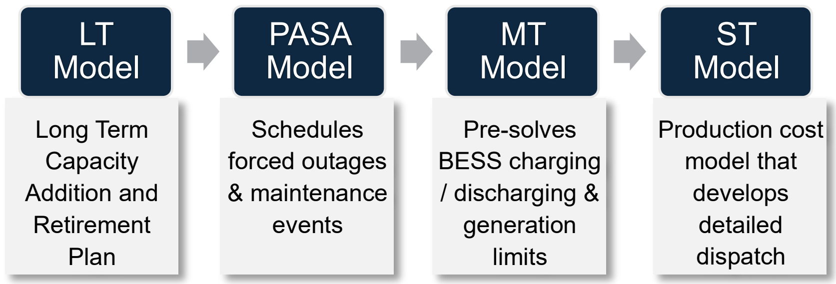


PLEXOS® works by dividing modeling into phases. Each phase performs a “handoff” and passes its results to the next phase. A brief description of the four phases of the PLEXOS® model is provided below:

- **Long Term Simulation Model (LT Model):** Performs a capacity expansion simulation over the long-term horizon. It evaluates the system and its needs over the entire horizon and attempts to minimize all types of costs (capital, fixed, variable and fuels) while meeting system requirements, providing an expansion plan.
- **Projected Assessment of System Adequacy Model (PASA Model):** Maximizes the system reliability when scheduling outages and creates scheduled maintenance events. It calculates the reliability statistics such as LOLE (Loss of Load Expectation).
- **Middle Term Simulation Model (MT Model):** The MT horizon is usually set for one year. It pre-solves the problem for the most granular phase of the model, identifying the best timing for battery charging and discharging and setting annual limits, such as CO2 emissions or annual energy limits on generators.
- **Short Term Simulation Model (ST Model):** Short Term Simulation Model is the most granular of the PLEXOS modules, and is commonly known as a production cost model. For the LUMA 2025 IRP, a chronological hourly simulation was used to solve the unit commitment and dispatch problem (SCUC & SCED), simulating actual system commitment and dispatch by LUMA operations.

These models are used in a sequential process, with each model handing off its results to the next model as illustrated in Figure 68 below.

Figure 67: PLEXOS Modeling Phases



The use of PLEXOS allowed LUMA to gain insights into complex interactions within the energy grid, anticipate challenges and devise optimal strategies for transitioning the Puerto Rico generation system to a more sustainable and reliable fleet. By using PLEXOS®, LUMA was able to gain practical knowledge to address the complexities of energy planning while transitioning to a strong, eco-friendly, and affordable power system for Puerto Rico.

8.2.2 2025 IRP Fixed Decision Assumptions

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

8.2.3 Additional Planning Criteria

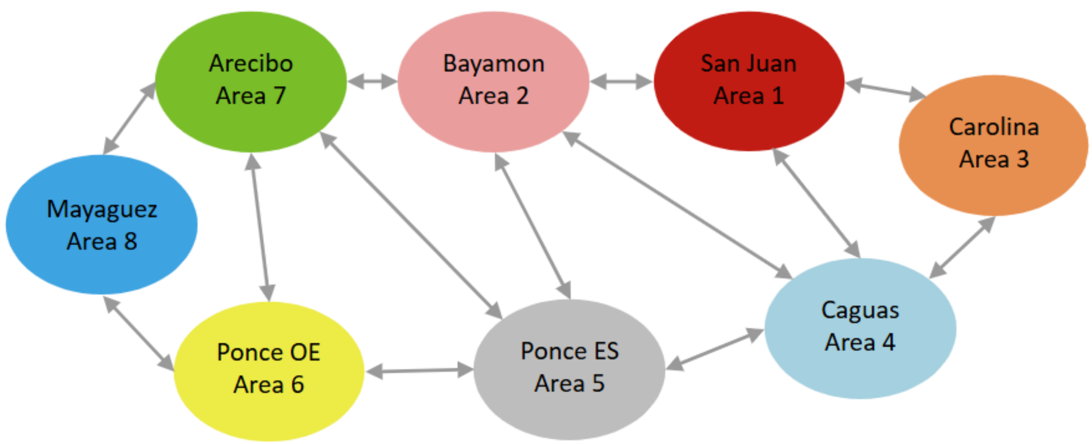
LUMA has established a list of planning criteria and outputs for multiple categories in addition to the Fixed Decisions. These were created with the input of stakeholders who participated in the SETPR meetings held around the Island. These were also reviewed with the Energy Bureau and the Energy Bureau's Consultant and updated to reflect changes in 2025. For example, the criteria related to RPS was modified by LUMA in consultation with the Energy Bureau's Consultant.

The additional planning criteria included, among others:

- Attain the new RPS requirement contained in Act 1-2025 by defining new annual targets for RPS that begins at zero in 2035 and then increases by 6.7% per year[142] reaching 100% RPS by 2050.
- Improve Loss of Load Expectation ("LOLE") to attain an industry-standard performance for Puerto Rico of 0.1 days/year (equivalent to ≤ 2.4 hours./year of unserved energy in a single outage event) within the 2025 to 2044 IRP planning horizon if possible. Since PLEXOS does not provide a LOLE value from the ST module, LUMA is using Expected Unserved Energy ("EUE") and the number of outage events to calculate LOLE.[143]
- Improve the geographic and technological diversity of energy resources
- Retire the existing heavy fuel-fired units as soon as practical

To provide reasonable geographic differentiation of energy resources sources and loads without creating an overly detailed geographic and electric model, LUMA chose to represent the Puerto Rico system as 8 Transmission Planning Areas (TPAs) in the resource planning model. Each TPA represents a group of contiguous municipalities. A similar geographic differentiation had been used in the last IRP filed by PREPA and other transmission planning analyses performed by LUMA and previously by PREPA. The existing T&D infrastructure was represented by 13 bi-directional transmission links, shown in Figure 69, that represent the collective T&D system connections and its approximate ability to move between the TPAs, i.e., the inter-TPA transfer capacity.

Figure 69: Simplified Transmission Planning Areas



The transfer capacity of these links, as measured in MWs, were used as initial constraints in the resource modeling. If the transfer limit is reached on any link and additional transfer capacity is needed, the model can choose the most cost effective option of either increasing the transfer capacity through an optional transmission upgrade and/or locating new energy resources to locations that would avoid or reduce the need for additional transfer capacity, e.g., locating new energy resources within the same TPA as the load being served. The ability of the transmission system to support the preferred resource plan and a

[142] The new RPS targets in response to the Act 1-2025 is based on beginning annual RPS targets in 2035 and reaching 100% RPS by 2050, i.e., 100% divided by 15 years = 6.7% per year.
[143] EUE: The summation of the expected number of megawatt (MW) hours of load that cannot be served because demand exceeds the available generation capacity. This energy-centric measure considers the number, magnitude and duration for all outage hours of the period. See page 44 of Resource Adequacy Study at https://energia.pr.gov/wp-content/uploads/sites/7/2023/12/20231220-AP20230004-Motion-Submitting-Final-Version-of-Resource-Adequacy-Analysis-Report.pdf

more detailed estimate of any upgrades necessary to support the plan is further assessed in a separate analysis using PSS/E, a dedicated transmission analysis tool.

8.2.4 Implementation of Planning Constraints in PLEXOS

Several planning constraints are common across the scenarios and are inputs to the PLEXOS model. LUMA and its Technical Consultant implemented some of these planning constraints as “Soft Constraints” for which a financial penalty is used to strongly encourage the constraint to be satisfied, with the associated penalty being assessed for constraint violations. The penalties are not shown as part of the actual costs of the resource plan in the PVRR values. The financial penalties serve as a strong financial incentive to the modeling software to define resource plans that meet the planning targets. The alternative to modeling a constraint as a soft constraint, is the use of a “Hard Constraint”. The latter is a constraint that must be met by the model, regardless of cost.

The key planning inputs and constraints include:

- New UBESS
  - Earliest COD is 2027
  - Added only in 20 MW blocks
  - Battery constraints implemented as Hard Constraints
- New Utility Scale Thermal and Renewable Generation
  - Earliest year solar and land-based wind can be added is 2027
  - Solar can only be added in 75 MW blocks
  - Thermal generation can only be added based on the size of the generic units described in Section 6
  - Earliest year offshore wind can be added is 2033
  - All constraints for new units implemented as Hard Constraints
- RPS Constraint
  - Among other changes, Act 1-2025 retained the target of Puerto Rico reaching 100% renewable energy for its electric supply by 2050. However, Act 1-2025 eliminated all RPS performance targets for years prior to 2050. In its May 13 R&O, the Energy Bureau ordered LUMA to model three RPS cases in the 2025 IRP that each assume a different starting point for the new interim RPS targets and their associated ramp rates for RPS increases to attain 100% RPS by 2050. The three scenarios include:

- Base Case RPS - target begins at 0% at the beginning 2035 and ramps to 100% by 2050 for all 12 Core scenarios (Scenarios 1 to 12) and all but the two supplemental scenarios noted below[144];
- Alternative RPS1 - targets begins in 2025 and ramp to 100% by 2050 (modeled only in Supplemental Scenario 16); and
- Alternative RPS2 - targets begin in 2044 and ramp to 100% by 2050 (modeled only in Supplemental Scenario 17).

- The RPS constraints were implemented in PLEXOS with the following additional characteristics:
  - Minimum Annual Constraints shown in Table 81 to achieve 100% RPS by 2050
  - RPS implemented as a Soft Constraint
  - The penalty applied for not achieving the RPS constraint is $9,000 / kWh

Table 81: Minimum Annual RPS

Year	Base Case RPS Constraint	Alternate RPS 1 Constraint	Alternate RPS 2 Constraint
2025	-	4%	-
2026	-	8%	-
2027	-	12%	-
2028	-	16%	-
2029	-	20%	-
2030	-	24%	-
2031	-	28%	-
2032	-	32%	-
2033	-	36%	-
2034	-	40%	-
2035	6.7%	44.0%	-
2036	13.3%	48.0%	-
2037	20.0%	52.0%	-
2038	26.7%	56.0%	-
2039	33.3%	60.0%	-
2040	40.0%	64.0%	-
2041	46.7%	68.0%	-
2042	53.3%	72.0%	-
2043	60.0%	76.0%	-
2044	66.7%	80.0%	16.7%
2045	73.3%	84.0%	33.3%
2046	80.0%	88.0%	50.0%

144 The results of the Core Scenarios are included in this report. The results of the supplemental scenarios are included in a supplemental report to be filed with the commission in November 2025.

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Year	Base Case RPS Constraint	Alternate RPS 1 Constraint	Alternate RPS 2 Constraint
2047	86.7%	92.0%	66.7%
2048	93.3%	96.0%	83.3%
2049	100.0%	100.0%	100.0%
2050	100.0%	100.0%	100.0%

- Expected Unserved Energy (EUE)
  - Section 5.1 provides an explanation of LUMA's selection of the target EUE values shown in Table 82
  - The modeling software uses a simplified method to account for EUE in the LT model which defines the build and retirement plan for the energy resources in the resulting resource plan. The calculation method used in the LT model estimates the impact of the EUE by treating forced outage (i.e., unplanned outages) rates as a continuous reduction in the unit capacity. The PASA module, which is run after the LT model, develops a more accurate probabilistic projection of the schedule of the reduction in unit capability during forced outages. The subsequent ST model uses the PASA projection of forecast outages and dispatches the energy resources to meet load and adjust dispatch to avoid EUE if possible, based on the resources available. The ST model uses the more accurate PASA projection of forced outages that utilizes a Stochastic simulation to forecast the random nature of forced outages. LUMA found that with the extremely high forced outage rates of the existing Puerto Rico generation fleet, the EUE results from the LT model varied significantly from EUE results from the ST model. Due to its use of the PASA module's superior Stochastic simulation-based method of estimating the impacts of forced outages, LUMA based its review of EUE performance solely on the results from the ST model[145]
  - The EUE was a soft constraint, and the penalty applied for not achieving the EUE constraint is $100,000 / kWh

Table 82: Maximum Annual EUE

Year	Maximum EUE Constraint (Hrs)
2030	60.6
2031	40.4
2032	26.9
2033	18.0
2034	12.0
2035	8.0
2036	5.3
2037	3.5

[145] The availability of an energy resource to serve load is impacted by both planned maintenance and forced outages. However, the LT and ST modules treat planned maintenance similarly so the difference in the EUE results between the two modules is primarily driven by their different methods of estimating the impacts of forced outages.

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Year	Maximum EUE Constraint (Hrs)
2038 - 2044	2.4

- Spinning reserves
  - Spinning reserve is unloaded generation that is rotating in synchronism with a utility grid. Minimum spinning reserves, synchronized to the system, equal the capacity of the largest unit online at any given time
  - Spinning reserve was implemented as a soft constraint, and the penalty applied for not achieving the spinning reserve constraint is $500 / MW
- Control reserves
  - Control reserves are short term measures used in power grids to handle unexpected events. Minimum control reserves available for system regulations are shown in Table ZZ below
  - LUMA does not currently maintain a “Regulation Down” requirement (i.e., a service that immediately decreases electricity generation in response to a system signal) since the need to decrease electricity generation is an infrequent event on the island. Loss of generation due to unplanned trips are much more frequent events. Historically when there is an event that creates a rapid and large excess of generation on the system, such as when multiple substations trip, LUMA will generally trip generation units to restore the load generation balance. The constraints used in the 2025 IRP assume that LUMA will gradually implement a Regulation Down requirement and reduce the Regulation Up requirement as more new dependable energy resources are added to the system. While the table does not represent a proposed evolution of the LUMA operating policy, it does represent a plausible evolution that can be considered as the resource fleet becomes more reliable
  - Control reserves were implemented as a soft constraint
  - The penalty applied for not achieving the Regulation Up Reserve constraint is $500 / MW
  - The penalty applied for not achieving the Regulation Down Reserve constraint is $500 / MW

Table 83: Minimum Annual Control Reserves

Year	Reserves for Regulation Up (MW)	Reserves for Regulation Down (MW)
[redacted]		

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Year	Reserves for Regulation Up (MW)	Reserves for Regulation Down (MW)
[redacted]		

- Transmission Transfer Capacity between TPAs
  - The maximum usable capacity between each TPA is listed in Table 84 below
  - Transmission transfer capacity was implemented as a hard constraint

Table 84: Summary of Estimated Transfer Capacity Between TPAs

Link Number	TPA A	TPA B	Transfer Capacity A to B (MW)	Transfer Capacity B to A (MW)
[redacted]				

* DC Transfer Limit

LUMA has modeled the Puerto Rico grid in PSSe to estimate the transfer capacity for each of the ties connecting the TPAs. Table 84 summarizes the preliminary, estimated power transfer capacity between each Transmission Planning Area resulting from this PSSe modeling. The values in Table 84 are based on an analysis completed in 2023 using a transmission model which represented the best representation of the transmission grid at the time. LUMA has continued to refine its grid models with new data from field verifications and operational experience. LUMA considers these values as estimates which could change over the course of the development of the IRP and through further refinement of the models LUMA uses to represent the electric system.

8.2.5 Planned and Forced Outage Modeling in PLEXOS

Forced outages, are both forced and unplanned outages that can occur at any time a generator is operating. Forced outage rates, or the frequency of forced outages, is largely driven by the age of a generating unit, the quality of the unit maintenance and inspections, and the historical reliability of the specific make and model of the unit. To model forced outages for resource adequacy analysis, many programs, including PLEXOS, use a generator specific Stochastic simulation method to determine a schedule of forced outages for each unit.

The purpose of using different scenarios in IRP planning is to assess the impacts of specific changes to the characteristics defined in the scenarios. For example, if a scenario was designed to test the impact of delaying the addition of a generator by one year, changes in results could be due to the generator delay but it could also be due to changes in the planned and forced outages. The delay in the generator addition can impact the modeling software's schedule for the planned outages, and each run can generate a new random placement of forced outage events. The differences in results are difficult to distinguish between those attributable to a change in the scenario characteristics and those attributable to a change in the schedule of planned or forced outages. Review of early simulation results showed that material differences in the results between runs were caused by the differences in the schedules of the planned and forced outages.

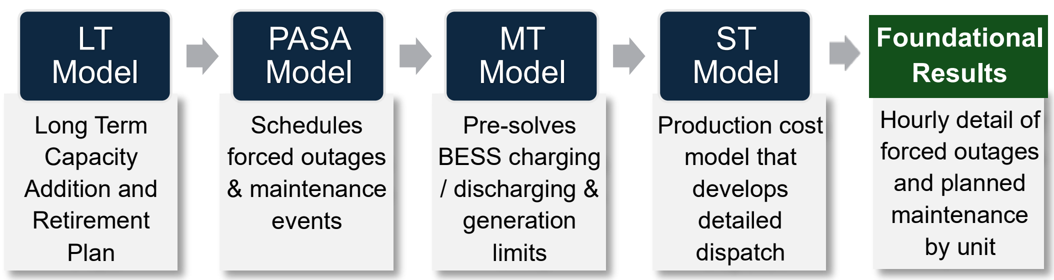
As discussed earlier, the PLEXOS modules include the LT, PASA, MT and ST, that, depending on the needs of the study, are often run sequentially in that order. Investigation of early results demonstrated an issue between the modules, related to outages. The primary role of the LT module is to determine the capacity expansion plan with a specific schedule of generation additions and retirements that will meet load and other criteria. The LT module uses a derate method as a simplified approach to estimate the long-term impacts to unit available due to planned maintenance and forced outages. For example, a 100 MW generator with a 10% forced outage rate and a planned maintenance that equates to 5% of the hours in a year, will be treated in the LT module as a perfect 85 MW generator with no maintenance or forced outage hours (i.e., 100 MW minus a 15% derate attributable to the combined effects of planned and forced outages). While this simplified approach may be appropriate for certain studies, it proved problematic for the LUMA IRP.

The planned and forced outages in the ST model are based on analysis performed in the PASA module. The PASA module schedules a specific time to perform planned maintenance, considering the planned maintenance needs of other units. The PASA module then uses a Stochastic simulation to schedule a repeatable pattern of forced outage events. These schedules of planned and forced outages are then fed into the ST module that performs the hourly unit commitment and economic dispatch. Due to the different methods of addressing planned and forced outages, the generation addition and retirement plan provided by the LT module proved insufficient to deliver acceptable EUE results in the ST module in a single pass of the PLEXOS modules.

This simplified method of deducting the planned maintenance and forced outage rates from the unit capacity to define the unit capacity available does not adequately account for the actual hourly impact of forced outages which removes 100% of the capacity of a unit during a full outage, not just the fraction of the capacity equal to the annual forced outage rate. In addition, the very high forced outage rate performance of the existing PREPA fleet of thermal generators, with a projected average forced outage rate for the IRP of 25% (weighted by capacity) which is over three times higher than the NERC national average in 2023 of 7.8%[146] for conventional generation.

To address these issues and stabilize the impact of planned maintenance and forced outages across different runs, LUMA developed a method that starts with an initial PLEXOS run, LT through ST, to determine the hourly outage schedule for individual generators, reflecting planned and forced outages. As the purpose of this foundational run is strictly to develop the outage schedule for use in all subsequent simulations, only the schedule of outages is used from this run. The outages are unknown at the time of the LT simulation but are known and available by the conclusion of the ST simulation. The resulting outage schedule is used as an input in all subsequent runs, with corresponding adjustments to the outage modelling in all of the modules (LT, PASA, MT and ST) and all runs. By including the specific outage schedule in subsequent runs, the problems associated with the LT's derate approximation for outages was resolved. Further, by holding the outages constant, there should be no variations in results, for example across scenarios, due to changes in generator outages. The process is summarized in Figure 71.

Figure 70: Foundational Run of PLEXOS



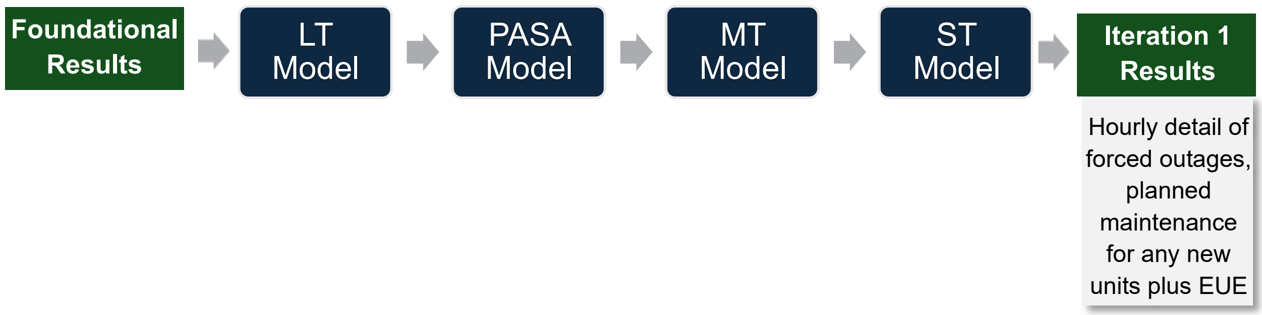
8.2.6 Loss of Load Expectation Modeling in PLEXOS

PLEXOS® does not have the capability to effectively use LOLE or EUE as a planning criteria input to drive the development of capacity expansion plans. PLEXOS does have some ability to influence energy resource build plans using soft constraint penalties for plans that do not achieve EUE results in both the LT and ST modules. However, as explained in Section 8.2.5, the simplified treatment of outages by PLEXOS in its LT model severely diminishes the ability to effectively adjust resource plans to meet EUE targets.

After consultation with the IRP Technical Consultant and Energy Exemplar, it was decided to utilize an iterative process, as a method to attain the desired LOLE results in the final resource plans. The iterative process first locks down the planned maintenance and forced outage data, as described above. It then requires feeding back into the LT model, as input to its capacity plan determination, the EUE hours, by TPA, based on the detailed results from the prior ST simulation (i.e., a feedback loop). This is done utilizing the fixed load adder variable in PLEXOS. Figure 72 below illustrates the first run performed for each scenario where the Foundational Results, described in Section 8.2.5, are fed into the LT model and then the EUE resulting from the ST model is compared to the EUE target values.

[146] North American Electric Reliability Corporation. (2024). *State of Reliability June 2024*, page 57. https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2024_Technical_Assessment.pdf

Figure 71: First Run of Each Scenario



This process is repeated in the second and subsequent iterative runs, adding to the fixed load adder for the unserved energy from all prior iterations as a cumulative fixed load input to the LT module. Adding in the EUE by hour, MW, and TPA provides a detailed signal, in terms of the hour, location (TPA), and magnitude (MW) via an artificial increase in load, using a fixed load adder to encourage the LT module to react in a fine-tuned manner to adjust the resource plan and reduce the amount of EUE ultimately to acceptable levels. Note the resource plan developed by the LT includes generation expansion, generation retirement, and transmission expansion. As the feedback loop is intended to give a refined signal to the LT model only, the feedback signal (i.e., fixed load adder) is removed before the subsequent ST is started. Figure 73 illustrates the process for the second and subsequent iterative runs.

Figure 72: Second and Subsequent Iterative Runs of Each Scenario

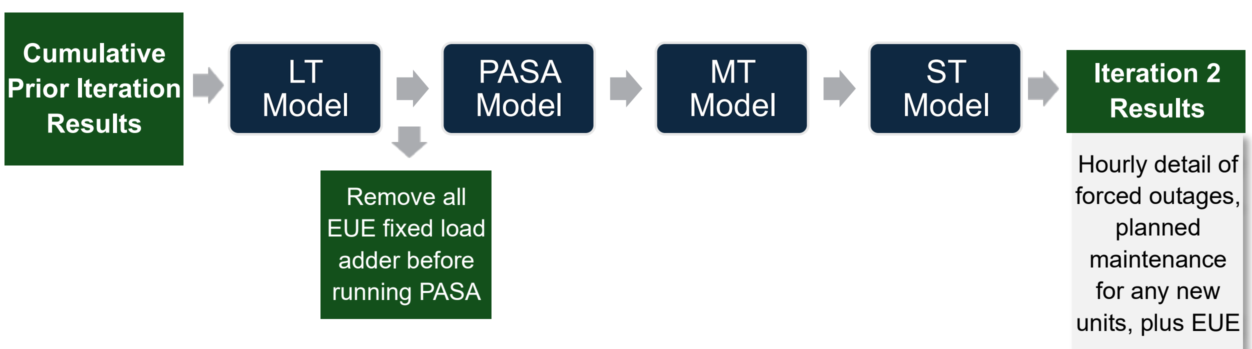
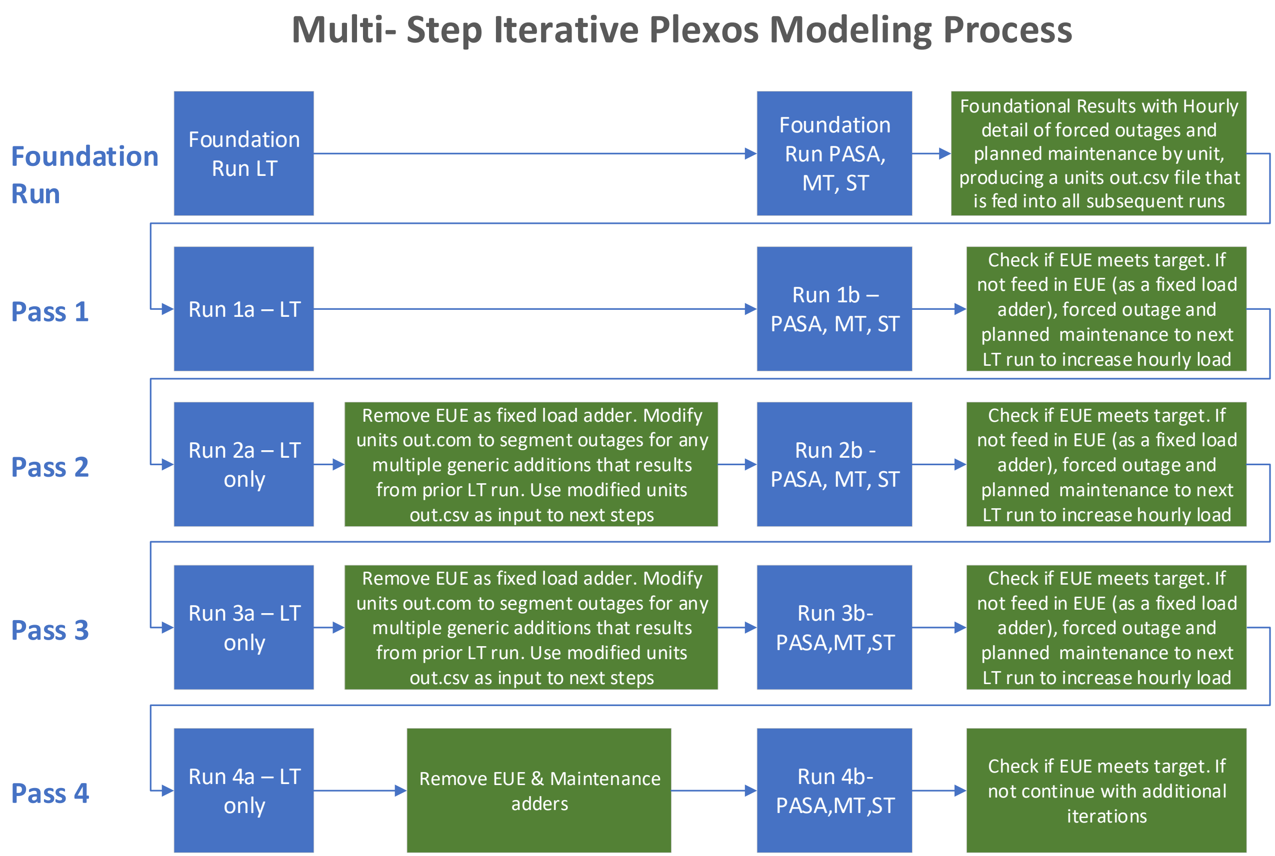


Figure 73 provides a more detailed illustration of the process used for the iterative runs.

Figure 73: Multi-Step Iterative PLEXOS Modeling Process



- The results of a foundational are used to obtain an initial set-up for forced and planned outages.
- The number of iterations needed to attain acceptable results varies by scenario but has ranged from 2 to 7 or more iterations

8.2.7 Characteristics of the Twelve Primary Scenarios

To develop a recommendation of a PRP, the Energy Bureau ordered LUMA to model and consider the results of the 12 Primary Scenarios listed in Table 8-6. The list of characteristics was discussed and agreed to by the Energy Bureau's Consultant and LUMA prior to the issuance of the Energy Bureau's May 13 R&O ordering their inclusion in the 2025 IRP. The specific characteristics of Primary Scenarios 1 - 6 and 12 were also discussed and agreed to by the Energy Bureau's Consultant and LUMA prior to the issuance of the Energy Bureau's May 13 R&O, which ordered their inclusion in the 2025 IRP. LUMA has designated the resulting resource plans optimized for these specific scenarios as Core Resource Plans. The specific characteristics of Primary Scenarios 7 – 11 were left to LUMA to decide to assess the flexibility of candidate Core Resource Plans under different conditions. LUMA has designated the resource plans that results from this Flexibility Analysis as Flex Resource Plans.

The data for the percent of customers with DBESS enrolled in a Controlled DBESS program and the percentage of battery energy capacity enrolled in a program, shown in Table 86 were defined at 5-year increments (i.e., 2025, 2030, 2035, 2040) during discussion between the Energy Bureau's technical consultant and LUMA. However, these details for the percent of customer enrollment and percent of battery capacity enrollment characteristics were not included in the Energy Bureau's May 13 R&O. To create Table 86, LUMA added annual interpolated increases to align with the 5-year incremental data discussed with the Energy Bureau's technical consultant.

Table 85: Characteristics of Twelve Primary Scenarios

Scenario	Scenario Description	Load	PV & UBESS CapEx	Natural Gas Plant CapEx + Bio Conversion Costs[147]	Level of DBESS Control	LNG Fuel Cost	Include Biodiesel	Fixed Decisions	Resulting Resource Plan
1	Base assumptions for all variables	Base	Base	Base	Base	Base	Yes	Base	Core Resource Plan A
2	High load conditions with base assumptions for other variables	High	Base	Base	Base	Base	Yes	Base	Core Resource Plan B
3	Base load with high natural gas plant capital costs	Base	Base	High	Base	Base	Yes	Base	Core Resource Plan C
4	Base load with low renewable energy capital costs and high fossil capital costs	Base	Low	High	Base	Base	Yes	Base	Core Resource Plan D
5	Base load with high natural gas fuel costs	Base	Base	Base	Base	High	Yes	Base	Core Resource Plan E
6	Base load with high natural gas fuel costs and high natural gas plant capital costs	Base	Base	High	Base	High	Yes	Base	Core Resource Plan F
7	Flex Run for Resource Plan B run under Scenario 1 conditions	Base	Base	Base	Base	Base	Yes	Base	Flex Resource Plan 1.B
8	Flex Run Resource Plan A run under Scenario 2 conditions	High	Base	Base	Base	Base	Yes	Base	Flex Resource Plan 2.A
9	Flex Run for Resource Plan A run under Low Load conditions	Low	Base	Base	Base	Base	Yes	Base	Flex Resource Plan Low.A
10	Flex Run of Resource Plan A run under Stress conditions	High	Base	High	Base	Base	Yes	Base	Resource Plan Stress.A
11	Flex Run of Resource Plan B run under Stress conditions	High	Base	High	Base	Base	Yes	Base	Resource Plan Stress.B
12	Base assumptions for all variables but biodiesel is unavailable	Base	Base	Base	Base	Base	No	Base	Core Resource Plan H

[147] Including the costs of Biodiesel conversion was not included in the characteristic of the 12 scenarios in the May 13, 2025, Energy Bureau order. LUMA chose to add biodiesel to this characteristic since LUMA judged it be consistent with the expressed intent of the Energy Bureau's Consultant's suggestion for this characteristic.

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Table 86: Variations on Controlled DBESS Program Enrollment

Variation	Percent of Customers with DBESS Enrolled in Controlled DBESS Program																% Battery Energy Capacity Enrolled in Program
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	
Most Likely	0%	0%	3%	7%	11%	15%	16%	17%	18%	19%	20%	21%	22%	23%	24%	25%	30%
Extremely High	0%	0%	6%	14%	22%	30%	34%	38%	42%	46%	50%	52%	54%	56%	58%	60%	100%

Table 87 provides a definition of the characteristics used to define the Primary and Supplemental Scenarios.

Table 87: Scenario Characteristic Description

Characteristic	Explanation
Load	Three variations of the load forecast were considered in the analysis a most likely forecast, a high forecast and low forecast. These are described in Section 3.
PV & UBESS CapEx	Two variations of the costs of utility scale PV and UBESS capital costs were included in the analysis a most likely forecast, and a low forecast. These are described in Section 6.
Natural gas plant CapEx + Bio Conversion Costs	Two variations of the costs of utility scale PV and UBESS were included in the analysis, a most likely forecast, and a high forecast. These are described in Section 6.
Level of DBESS Control	The level of the most likely DBESS control forecast, as mentioned in Table 8-7, was used in all but a single scenario. Supplemental scenario 13 incorporated an extremely high forecast for the level of DBESS control. These are described in Section 3.2.
LNG Fuel Cost	Two variations of the costs of LNG fuel cost were included in the analysis, a most likely forecast, and a high forecast. These are described in Section 7.
Include Biodiesel	Biodiesel was considered as a fuel option in all but a single scenario. Only Primary Scenario 12 excluded biodiesel with the assumption that it would be too costly to be a viable fuel option.
Fixed Decisions	The fixed decisions were the same in all 12 Primary Scenarios.

8.2.8 Flexibility Analysis Methodology Description

LUMA's resource modeling process creates resource plans that are optimized to meet the planning constraints, at the least cost, for the set of characteristics described in a single Scenario. The characteristics of Primary Scenario 1 were defined to include the most likely conditions for each of the characteristics that LUMA would expect over the planning horizon of the 2025 IRP. Since no one can reliably predict the future with confidence, it is common practice when developing an IRP to consider alternative, plausible future conditions that vary from the most likely conditions. The Energy Bureau's list of the 12 Primary Scenarios describe 12 different plausible sets of future characteristics.

For the set of conditions described by each Scenario, the modeling software can create an optimal plan for the addition and retirement of energy resources, as well as transmission expansion, based on the input assumptions and candidate resources, that meet the planning criteria at least cost. For example, LUMA first used the modeling software to define a Resource Plan (that was optimized for the conditions of Scenario 1. The resulting optimized Resource Plan, consisting of additions and retirements created based on Primary Scenario 1 conditions, was designated Resource Plan A. This process was repeated for Primary Scenario 1 to 6 and 12, yielding the resulting Resource Plan listed in the last column of Table 11.

To assess which Resource Plans perform best under a variety of uncertain future conditions, LUMA developed Flexibility Analyses. The premise behind the Flexibility Analysis is that any Resource Plan may need to operate under future conditions that differ from the original forecast. In addition, it does not make sense to assume that a prudent utility plan will remain unchanged if future conditions arise that are significantly different from that which was forecast. Therefore, the ability of a given Resource Plan to adapt to different future conditions (i.e., flexibility) is an important and valuable attribute in choosing a Preferred Resource Plan. For the Flexibility Analysis portion of the IRP development, it was assumed that:

- The Flexibility Analysis recognizes that planning expenditures and contractual commitments will need to be made that can impact the ability of plans to adapt to changing future conditions. In the Flexibility Analysis, Core Resource Plans have their resource addition plans locked-in (i.e., with no reduction or elimination of resource additions allowed) for the years 2025 to 2031. This period was chosen given that:
    - Once a Resource Plan is approved and implemented, it will take multiple years to have sufficient data to confirm that a change in the resource plan is needed to adapt to conditions that vary from the forecast.
    - The decision to lock-in the resource additions in a Core Resource Plan through 2031 was since planned additions of new resources will begin when the 2025 IRP is approved and progress through their procurement and development process. These implementation activities will result in contractual commitments that would be problematic and/or costly to modify. Therefore, all decisions for resource additions in the Core Resource Plans through and including 2031 are considered locked-in and not subject to elimination.
- The Flexibility Analysis also recognizes that prudent utilities planners would not sit idle and accept resource plans that do not, for example, provide sufficient resources to serve a customer load that is higher than originally forecasted. Therefore, the Flexibility Analysis allows incremental resource additions above those that are fixed decisions or locked in from the Core Resource Plan. Changes to delay retirement plans were also allowed in the Flexibility Analysis. Allowing incremental resources and delays in the retirement plans were to represent pre-2032 adaptation to meet higher loads than forecast. However, any incremental additions to the Core Resource Plan must include the same lead-time limitations used in the definition of the Core Resource Plans plan, i.e., no new BESS additions can be made prior to 2027 and no new generating units or transmission additions before 2030.
- Within the limitations of the constraints described in items 1 and 2 above, the modeling software is allowed to adjust the Core Resource Plan to adapt to the different scenario conditions used in the Flexibility Analyses. In summary, the flexibility analysis allowable adjustments to the Core Resource Plan include:
    - Add additional batteries beginning in 2027
    - Add additional generating units or transmission additions beginning in 2030
    - Delay the date of any retirement

For those Resource Plans that are feasible (i.e., meet the reliability requirements), the primary indicator used to assess and compare the Resource Plans is PVRR. PVRR is the total cost of electricity production including capital and operating expenditures over the 20-year term of the IRP, 2025 to 2044, which is then discounted to reflect the time value of money. The PVRR is also the primary metric to compare the ability of a Resource Plan to adapt to a range of different future conditions, including different load forecasts and cost scenarios.

8.2.9 Resource Plans Included in Flexibility Analysis

Once the Core Modeling was completed, Resource Plans A, B, and H resulting from Primary Scenarios 1, 2 and 12 were included as the primary candidate Resource Plans for assessment within the Flexibility Analysis. Each of these Resource Plans were then run under each of the conditions represented by Primary Scenarios 1, base – most likely conditions; Primary Scenario 2, high load forecast; and a stress scenario that included both high load forecast and high natural gas plant capital costs and high biodiesel conversion costs. Table 88 provides a summary of the modeling completed for the Flexibility Analysis.

Table 88: Resource Plans Included in Flexibility Analysis

Scenario	Resource Plan A	Resource Plan B
Scenario 1- Base-Most Likely	Resource Plan A optimum Resource Plan created for conditions of Scenario 1 (Scenario 1)	Resource Plan 1.B – Flex Run for Resource Plan B run under Scenario 1 conditions (Scenario 7)
Scenario 2- High Load	Resource Plan 2.A – Flex Resource Plan A run under Scenario 2 conditions (Scenario 8)	Resource Plan B – optimum Resource Plan created for conditions of Scenario 2 (Scenario 2)
Stress- High Cost and High Load	Resource Plan Stress.A – Flex run of Resource Plan A run under Stress conditions (Scenario 10)	Resource Plan Flex.B- Flex run of Resource Plan B run under Stress conditions (Scenario 11)
Low Load Scenario	Resource Plan Low.A - Flex run for Resource Plan A run under Low Load conditions (Scenario 9)	

8.2.10 Supplemental Scenarios

Table 89 lists the five Supplemental Scenarios that were defined jointly by LUMA and the Energy Bureau Consultant. These scenarios were defined to provide useful information to understand additional resource options that had been discussed but were thought to be less likely to contribute to the selection of the PRP. The results of these Supplemental Scenarios are not included in this report but will be filed in a supplemental filing that will also include the results of the PSS/E transmission modeling of the PRP.

Table 89: Supplemental Scenarios

Scenario	Description	Load	PV & UBESS CapEx	Natural Gas Plant CapEx + Bio Conversion Costs	Level of DBESS Control	LNG Fuel Cost	Include Biodiesel	Fixed Decisions	Resulting Resource Plan
13	High DBESS control with base assumptions for other variables	Base	Base	Base	High	Base	Yes	Base	Resource Plan I
14	No NGCC 460 MW San Juan	Base	Base	Base	Base	Base	Yes	No NGCC	Resource Plan J
15	Marine Cable	Base	Base	Base	Base	Base	Yes	Base	Resource Plan K
16	Alternative RPS 1 – Assumes goal starts in 2025 and then ramps to 100% by 2050.	Base	Base	Base	Base	Base	Yes	Base	Resource Plan L
17	Alternative RPS 2 – Initial targets start between 2040 and 2044 and then ramps to 100% by 2050.	Base	Base	Base	Base	Base	Yes	Base	Resource Plan M

8.2.11 Example of Multistep Iterative Results to Achieve EUE Target

As described above in Section 8.2.6, the LUMA modeling methodology incorporated a multi-step iterative process to achieve an acceptable LOLE result as measured by EUE of less than or equal to 2.4 hours/year and less than or equal to a single unserved energy event. Table 90 below summarizes the EUE results for the four iterations required to reduce the annual EUE to the targeted value for Resource Plan Hybrid A. The headings designate the step in the iterative process, with “b” indicating the results at the end of the ST for each of the steps (e.g., 1b is the first ST, 2b is the second ST). As can be seen in the table, the EUE hours and energy improve as the iterations proceed, ultimately reaching the EUE target by step 4b of the iterative process.

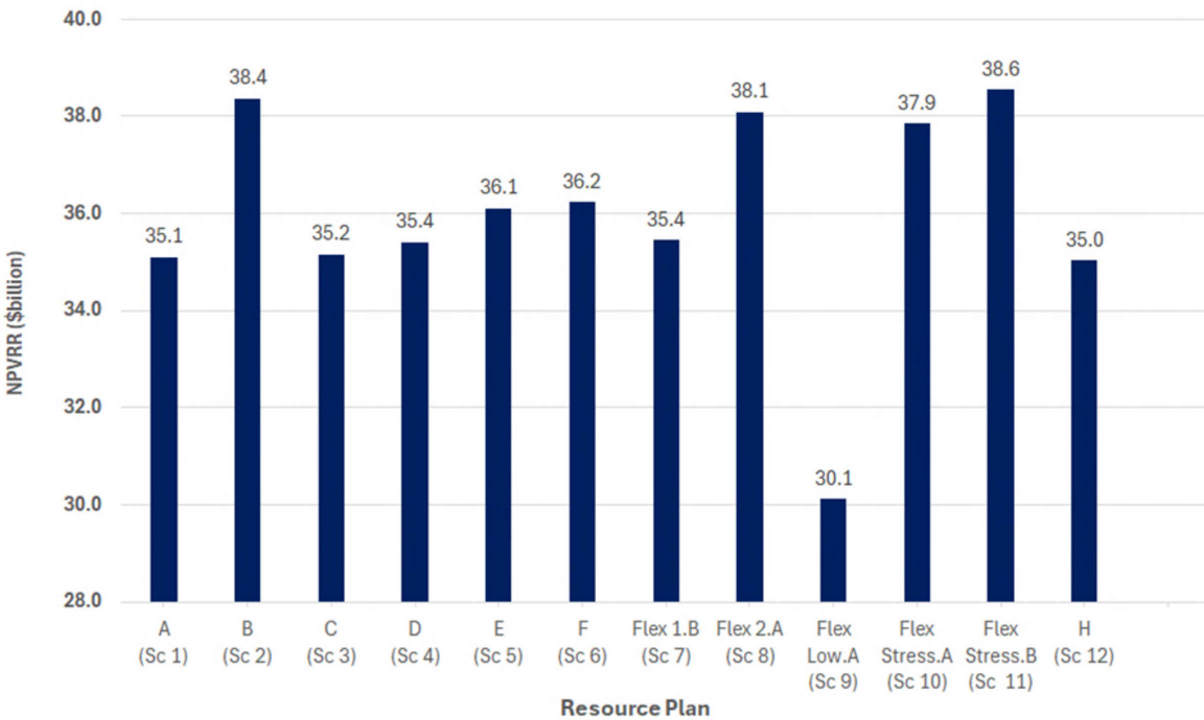
Table 90: Results of Multi-Step EUE Reduction Process for the development of Resource Plan A

Year	Run 1b		Run 2b		Run 3b		Run 4b		Target EUE (hours)	
	EUE (Hours)	EUE (GWh)	EUE (Hours)	EUE (GWh)	EUE (Hours)	EUE (GWh)	EUE (Hours)	EUE (GWh)	Number of EUE Events	
2025	377	51.7	376	51.7	375	51.7	375	51.7	79	No Target
2026	8	1.6	8	1.6	8	1.6	8	1.6	1	No Target
2027	28	3.2	29	3.2	27	3.2	34	3.2	10	No Target
2028	-	-	-	-	-	-	-	-	-	No Target
2029	-	-	-	-	-	-	-	-	-	No Target
2030	38	7.1	-	-	-	-	-	-	-	60.6
2031	67	16.0	7	0.3	4	0.2	5	0.2	3	40.4
2032	84	25.9	6	0.3	-	-	-	-	-	26.9
2033	129	24.3	36	4.3	17	2.7	-	-	-	18
2034	24	6.1	15	2.3	18	2.0	-	-	-	12
2035	128	51.7	14	2.1	-	-	-	-	-	8
2036	77	10.7	11	1.6	-	-	-	-	-	5.3
2037	92	20.1	27	7.2	-	-	-	-	-	3.5
2038	75	20.2	27	5.1	-	-	-	-	-	2.4
2039	42	5.6	45	11.9	-	-	-	-	-	2.4
2040	64	12.3	-	-	-	-	-	-	-	2.4
2041	106	20.0	-	-	-	-	-	-	-	2.4
2042	12	1.8	-	-	-	-	-	-	-	2.4
2043	-	-	-	-	-	-	-	-	-	2.4
2044	-	-	-	-	-	-	-	-	-	2.4

8.2.12 PVRR Results

A chart of Sensitivity Analysis Present Value Revenue Requirement (PVRR) results with an accompanying data table is provided below in Figure 74

Figure 74: Twenty-Year PVRR for Resource Plans Resulting from the 12 Primary Scenarios



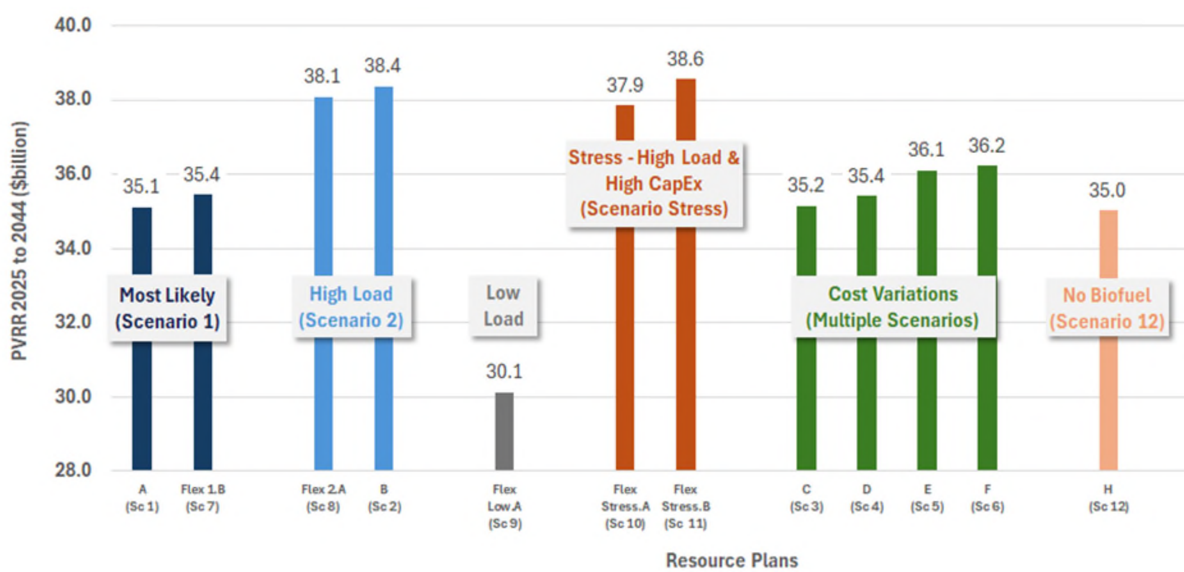
Primary Scenarios 1 to 12 have a variety of assumptions associated with costs, load, and fuel availability. Figure 75 shows the results for the same 12 Primary Scenarios rearranged and grouped according to common scenario characteristics. The Low and the Stress conditions represent additional sets of conditions which LUMA used to conduct the Flexibility Analyses, shown in Scenarios 9, 10, and 11. The Low conditions were only used as a flexibility assessment of Resource Plan Core A, therefore, there is only results shown for the single Scenario (i.e., Scenario 8) that includes the Low Conditions. The last group labeled Cost Variations (Multiple Scenarios) are the Core Resource Plans resulting from Scenario 3, 4, 5, and 6, each of which had different cost characteristics.

Each of the Resource Plans resulting from the Primary Scenarios included transmission system upgrades to increase the transfer capacity between TPAs. In addition to providing candidate expansion generation resources with their costs and technical characteristics, LUMA provided candidate transmission expansion projects to the model, so that it could choose to expand the 13 transmission links connecting the eight TPAs, as shown earlier. PLEXOS did consider the tradeoffs between building generation closer to load, or building potentially more attractive generation further from load, relying on the existing and expanded transmission grid to transmit the power from generation to the load. Table 91 lists the transmission upgrades added between the noted TPAs, and the year is it was added for each resource plan.

Table 91: 230 kV Transmission Link Upgrades

Resource Plan / Scenario	Transmission Lines (Year Built)		
PRP / Scenario 1	Carolina-San Juan (2030)	Mayaguez-Ponce OE (2030)	Ponce ES-Caguas (2030)
A / Scenario 1	Carolina-San Juan (2030)	Mayaguez-Ponce OE (2030)	Ponce ES-Caguas (2031)
B / Scenario 2	Carolina-San Juan (2030)	Mayaguez-Ponce OE (2030)	Ponce ES-Caguas (2030)
C / Scenario 3	Carolina-San Juan (2030)	Mayaguez-Ponce OE (2030)	Ponce ES-Caguas (2033)
D / Scenario 4	Carolina-San Juan (2030)	Mayaguez-Ponce OE (2030)	Ponce ES-Caguas (2030)
E / Scenario 5	Carolina-San Juan (2031)	Mayaguez-Ponce OE (2030)	Ponce ES-Caguas (2033)
F / Scenario 6	Carolina-San Juan (2030)	Mayaguez-Ponce OE (2030)	Ponce ES-Caguas (2031)
1.B / Scenario 7	Carolina-San Juan (2030)	Mayaguez-Ponce OE (2030)	Ponce ES-Caguas (2030)
2.A / Scenario 8	Carolina-San Juan (2030)	Mayaguez-Ponce OE (2030)	Ponce ES-Caguas (2031)
	Ponce ES-Bayamon (2030)	Ponce OE-Arecibo (2030)	Bayamon-Arecibo (2033)
Low.A / Scenario 9	Carolina-San Juan (2030)	Mayaguez-Ponce OE (2030)	Ponce ES-Caguas (2031)
Stress.A / Scenario 10	Carolina-San Juan (2030)	Mayaguez-Ponce OE (2030)	Ponce ES-Caguas (2031)
	Ponce ES-Bayamon (2030)	Ponce OE-Arecibo (2030)	
Stress.B / Scenario 11	Carolina-San Juan (2030)	Mayaguez-Ponce OE (2030)	Ponce ES-Caguas (2030)
H / Scenario 12	Carolina-San Juan (2030)	Mayaguez-Ponce OE (2030)	Ponce ES-Caguas (2030)

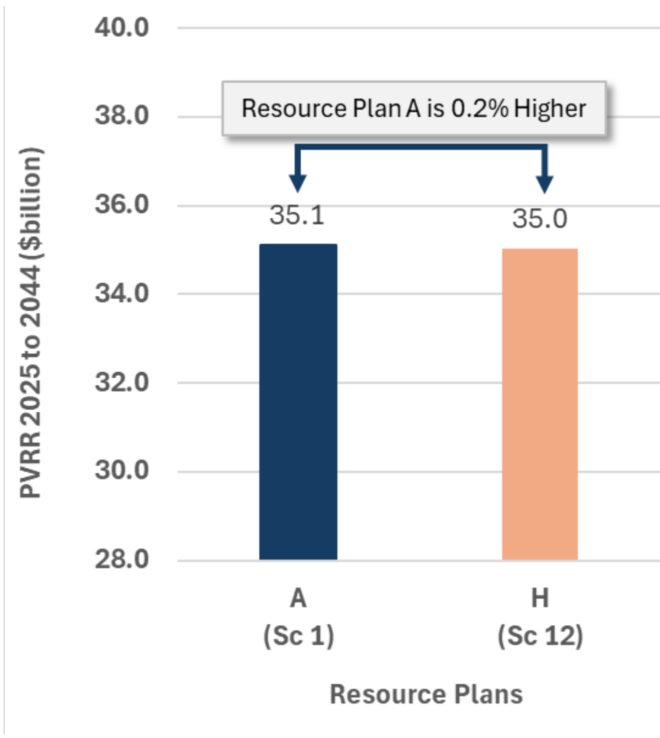
Figure 75: Reordered 20-Year PVRR for Resource Plans Resulting from the 12 Primary Scenarios



8.2.13 Results for Resource Plan A and Resource Plan H

The Flexibility Analysis provides results that indicate that with the most likely forecasts and assumptions represented by Scenario 1, Resource Plan H (the no biodiesel resource plan) provides the least cost alternative. However, as shown in Figure 76, the PVRR difference between Resource Plan A (created under the most likely conditions) and Resource Plan H (also created under the most likely conditions except that biodiesel is excluded as an option) is only 0.2%

Figure 76: PVRR Difference Between Core Resource Plan A and Core Resource Plan H



Given the near-parity of these results, LUMA chose to further investigate these two resource plans by performing a sensitivity analysis for two issues: (1) battery round trip efficiency; and (2) amount and timing of the battery additions.

8.2.14 Battery Round Trip Efficiency

While reviewing the results of Core Resource Plan A and H, it became apparent to LUMA that both the UBESS and the DBESS round trip efficiency (i.e., the combined effect of the charge and discharge efficiencies) had been entered into PLEXOS at unrealistically high numbers. The UBESS round trip efficiency was set at 90% and the DBESS was set at 100% efficiency. Further, LUMA found this error in the battery efficiency was common to all the scenario results that had been completed. By the time the error in the UBESS and DBESS efficiencies data had been discovered, the majority of the planned PLEXOS modeling had been completed with the erroneous efficiency data. LUMA determined there was insufficient time remaining to revise and remodel the numerous PLEXOS runs that had been completed prior to the required October 17, 2025, filing for the 2025 IRP report.

Using a corrected 85% round trip efficiency from the 2024 National Renewable Energy Laboratory (NREL) 2024 Annual Technology Baseline[148] for both the UBESS and DBESS, LUMA reran the PLEXOS runs for Resource Plan A and Resource Plan H. LUMA chose to rerun the two resource plans to compare the results prior to the correction to determine the impact resulting from the BESS round trip efficiency error. The reruns yielded only a 0.1% higher PVRR value through 2044 for both Resource Plan A and Resource Plan H when comparing the results with the battery efficiency correction to the earlier results without the correction. The difference between the PVRR of the two Resource Plans, A and H, with the battery efficiency correction compared to the difference for both resource plans without the correction was only $1.9M, or 0.005% of the PVRR. Based on the results of rerunning these two resource plans with and without the battery efficiency correction, LUMA formed two conclusions:

- First, the correction to the battery round trip efficiency did not materially impact the PVRR values or change the relative ranking of the PVRR results between Resource Plans A and H.
- Second, since there was not a significant difference in the number of batteries built across the 12 Primary Scenarios (most of the batteries built were fixed decisions that were common across all the scenarios), correcting the battery efficiency value in the remaining resource plans should not materially impact the PVRR values or change the relative ranking of the Resource Plan PVRR results.

8.2.15 Battery Addition Analysis of Resource Plan A and H

Resource Plans with significant variable renewable energy resources, such as wind and solar PV generation, often benefit from the addition of batteries to assist with the role of storing the renewable energy for later use during peak loads or real-time smoothing of the variable production output. As noted, the Fixed Decisions include 1,005 MW of new solar generation and 1,790 MW of battery capacity, all with planned operation prior to 2028.

Resource Plan A builds and converts energy resources to use biodiesel and does not build any other renewable technologies as economic additions. The only new utility scale solar additions built in Resource Plan A were those included as fixed decisions. In addition, no additional UBESS were built in Resource Plan A, beyond those included in the Fixed Decisions. Table 92 provides a summary of the economic additions of the utility scale renewable technologies in Resource Plan A.

Table 92: Resource Plan A Economic Additions of Renewable Resources (MW)

Technology	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
Biodiesel Conversions - Legacy Units	178									210	**388**
New Genera Peaking Unit Biodiesel Conversions	36				172						**208**
New and Converted Biodiesel		226	452		452	373					**1,503**
Total	**214**	**226**	**452**	**-**	**624**	**373**	**-**	**-**	**-**	**210**	**2,099**

LUMA noticed the economic additions defined in the results of Resource Plan H added a significant amount of new solar, land-based wind and offshore wind to meet the RPS targets that begin in 2035. In addition, as with Resource Plan A no additional UBESS were built in Resource Plan H beyond those

[148] NREL (National Renewable Energy Laboratory). 2024. 2024 Annual Technology Baseline, Version 3. Golden, CO: National Renewable Energy Laboratory. The roundtrip efficiency of the NREL data for the utility, commercial and residential batteries are all 85%.

included in the fixed decisions. Table 93 provides a summary of the economic additions of the utility scale renewable technologies in Resource Plan H.

Table 93: Resource Plan H Economic Additions of Renewable Resources (MW)

Technology	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
New Solar						75	300	225		75		**675**
New Wind	225								150	150	300	**825**
New Offshore Wind								75	75	75	75	**300**
Total	**225**	**-**	**-**	**-**	**-**	**75**	**300**	**300**	**225**	**300**	**375**	**1,800**

LUMA viewed the lack of economic UBESS additions in Resource Plan H as notable since LUMA expected that there would be a much larger need for battery capacity in Resource Plan H than in Resource Plan A given the additional 1,800 MW of variable renewable energy resources in the plan. Based on the lack of additional battery additions in Resource Plan H, LUMA decided to vary the amount of batteries included as Fixed Decisions by rerunning Resource Plans A and H to make the ASAP Phase 2 batteries optional additions and to correct the round-trip efficiencies for all batteries to 85%. This change allowed the modeling program to choose when and how much new battery capacity was justified based on economics or reliability reasons. As discussed in Section 6, in the original modeling runs for the scenarios, LUMA had included as a fixed addition of 424.9 MW of ASAP Phase 2 capacity (assumed to be 1699.6 MWh energy capacity), added in December 2026, from a total of 13 BESS projects. If the system had too much battery capacity or it was added too early, LUMA expected the results of remodeling Resource Plans A and H to show a difference in the amount of BESS built, the date it was built or both.

The results of changing the ASAP Phase 2 batteries to optional resources shifted the timing of BESS installation. Specifically, the results showed that by changing the ASAP Phase 2 batteries from fixed to optional decisions, both scenarios delayed the addition of the batteries to later years. Table 94 summarizes the impact from changing the ASAP Phase 2 batteries from fixed to optional additions and correcting the round-trip efficiencies for all batteries for both Resource Plans A and H.

Table 94: Comparison of Resource Plans A and H for Fixed vs. Economic Additions of ASAP Phase 2 Batteries and Battery Efficiency Correction

Resource Plan	2026 Additions (MW)	2030 Additions (MW)	2031 Additions (MW)	2039 Additions (MW)	Total Additions (MW)	PVRR ($Billion)	PVRR ($Billion)	PVRR (%)
Resource Plan A								
With ASAP Ph 2 Addition as a Fixed Decision	424.9				424.9	$35.10		
With ASAP Ph 2 Optional Addition + Efficiency Change		94.5	330.4		424.9	$34.63	$34.63	
Reduction in PVRR With Optional ASAP Ph 2 and Efficiency Correction						**($0.47)**		**(1.3%)**
Resource Plan H								
With ASAP Ph 2 Fixed Addition as a Fixed Decision	424.9				424.9	$35.03		
With ASAP Ph 2 Optional Addition + Efficiency Change		56.0	366.0	42.9[149]	464.9	$34.91	$34.91	
Reduction in PVRR With Optional ASAP Ph 2 and Efficiency Correction						**($0.12)**		**(0.3%)**
Difference in PVRR for Resource Plan A and H With ASAP Ph 2 Optional and Efficiency Correction							**($0.28)**	**(0.8%)**

[149] The 2039 battery additions for Resource Plan H with ASAP Ph 2 as optional batteries and correcting the round-trip efficiency, include the final 2.9 MW of ASAP Phase 2 batteries plus the addition of a 40 MW battery with 10-hour of storage capacity. The original results for Resource Plan H with the ASAP Phase 2 batteries as fixed additions and the original erroneous higher battery round trip efficiencies did not add any optional batteries through 2044.

The results of the ASAP Phase 2 as optional additions showed that the full capacity of the ASAP Phase 2 battery projects (i.e., 424.9 MW) was needed in both resource plans. The results also showed that the ASAP Phase 2 batteries were not needed until 2030 and 2031. This delay to the battery installation resulted in substantial savings in PVRR for Resource Plan A, $0.47 billion savings even with the offset of higher costs due to the lower but more accurate battery efficiency. Similar changes to Resource Plan H resulted in a $0.12 billion PVRR savings. In addition, the combined impact of changing the ASAP Phase 2 batteries to optional and correcting the battery efficiency results in Resource Plan A showing a $0.28 billion lower PVRR than that of Resource Plan H with the same changes. Table 95 below provides a graphical illustration of the differences in Resource Plans A and H with both including the ASAP Phase 2 optionality and the battery efficiency correction.

8.2.16 New Thermal Generation Additions

Resource Plan A with the ASAP Phase 2 batteries as optional additions includes an efficient transition of new thermal generation to renewable resources burning biodiesel fuel. As shown in Table 95, a full 70% of the new thermal generation added in Resource Plan A is either planned to burn biodiesel from its initial operation or is converted to burn biodiesel prior to 2044.

Table 95: Resource Plan A Percentage of New Thermal Generation Built or Converted to Renewable Biodiesel

Thermal Generator	Capacity Built (MW)[150]	Capacity Built or Converted to Renewable Biofuel (MW)	Percentage of Capacity Built or Converted to Renewable Biofuel	Notes
Fixed Decision Thermal Generation				
Energiza	478	0		
New Genera Units	244	36		Built as NG then 36 MW is converted
New Natural Gas Generation				
7F.05 1x1_S Juan	373	373		Built as NG then converted
LM2500 1x0_S Juan	35			
7F.05 1x1_Ponce OE	373	373		Built as NG then converted
18V50DF 1x0_Ponce OE	18	18		Built as NG then converted
New Biodiesel Generation				
7F.05 1x0_Ponce ES Biodiesel	226	226		Built as biodiesel
7F.05 1x0_S Juan Biodiesel	226	226		Built as biodiesel
7F.05 1x0_Caguas Biodiesel	226	226		Built as biodiesel
7F.05 1x0_Bayamon Biodiesel	226	226		Built as biodiesel
Total	**2,425**	**1,704**	**70%**	

As shown in Table 96 Resource Plan H, with no biodiesel and the ASAP Phase 2 as optional additions, also adds 2,400 MW of new thermal generation, all of which is fueled with natural gas. However, all the new natural gas fueled generation would have rapidly diminishing usefulness as the island moves

[150] The thermal capacity built does not include the 800 MW of emergency generation that is included in the Fixed Decisions that is expected retire after the installation of the San Juan 478 MW.

towards its goal of 100% renewable generation unless an alternate renewable fuel such as renewable diesel or hydrogen fuel becomes a viable option.

Table 96: Resource Plan H Percentage of New Thermal Generation Built or Converted to Renewable Fuel

Thermal Generator	Capacity Built (MW)[151]	New and Converted Renewable Capacity (MW)	Percentage of Capacity Built or Converted to Renewable Fuel	Notes
Fixed Decisions				
Thermal Gen	478	**0**		**No biofuel conversion**
New Genera Units	244	**0**		**No biofuel conversion**
New Natural Gas Gen				
7F.05 1x0_Ponce OE	226	**0**		**No biofuel conversion**
7F.05 1x0_S Juan	452	**0**		**No biofuel conversion**
7F.05 1x1_S Juan	373	**0**		**No biofuel conversion**
LM2500 1x0_S Juan	35	**0**		**No biofuel conversion**
LM2500 1x0_Ponce OE	**70**	**0**		**No biofuel conversion**
7F.05 1x0_Caguas	226	**0**		**No biofuel conversion**
7F.05 1x0_Mayaguez	226	**0**		**No biofuel conversion**
LM2500 1x0_Arecibo	35	**0**		**No biofuel conversion**
LM2500 1x0_Ponce ES	35	**0**		**No biofuel conversion**
Total	**2,400**	**0**	**0%**	

8.2.17 Transmission Network Considerations for Biodiesel vs No Biodiesel Resource Plans (A vs H)

Resource Plan A adds the largest capacity new energy resources to either San Juan or Costa Sur where there is existing fuel delivery infrastructure and existing transmission interconnections to the legacy generators. Resource Plan H adds a significant amount of wind and solar generation. These generators will need to be in locations with excellent solar and wind potential, which will be in new, greenfield locations, away from existing transmission infrastructure. Resource Plan H also requires significant new thermal generation. For these reasons, Resource Plan H will require more investment in grid improvements than Resource Plan A.

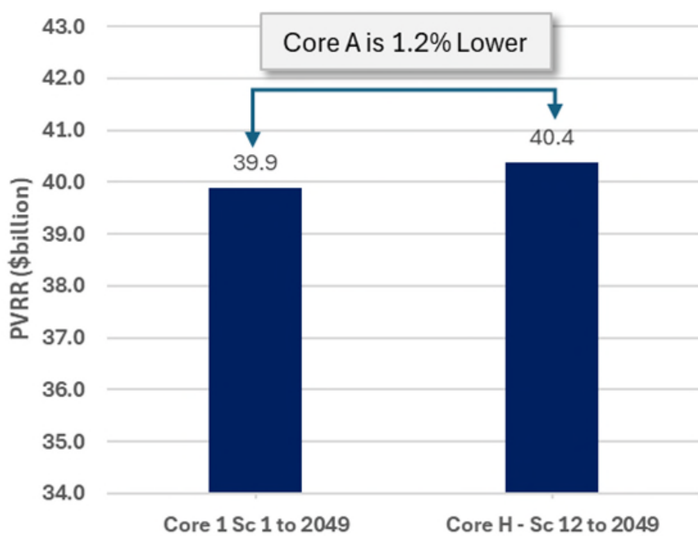
8.2.18 Extended Analysis Until 2050 for Biodiesel vs No Biodiesel Resource Plans (A vs H)

As is prudent practice in planning and financial models, to ensure “end effects” did not have an inappropriate influence on the results (e.g., look ahead window) the LT configuration was extended through 2049. Modeling results over a particular planning window can be skewed by end effects when a significant amount of resources is installed around the end of the planning period. In addition, during the planning period, as part of its feasibility and optimality considerations, PLEXOS looks beyond each year being simulated, into future years, to capture the impact of events throughout the planning period. Though the planning period for the 2025 IRP ends in 2044, the LT was configured to simulate through the end of 2049 to assess the appropriateness of end effects at the end of 2044. Due to the closeness of the PVRR

[151] Ibid

numbers for Resource Plans A and H, the remaining modules of PLEXOS were configured to run the additional years (2045-2049) and the PVRR calculations extended to capture the period through 2049. This was done independent of the ASAP Phase 2 consideration (i.e., ASAP Phase 2 BESS were continued to be modelled as fixed, without the BESS efficiency correction in this set of simulations).

Figure 77: PVRR extended through 2049



As described previously, the RPS requirement starts in 2035 and is ramping up to 100% in 2050, consistent with Act 1. As a result, in Resource Plan H, solar and wind generation ramps up to satisfy the increasing RPS requirement toward the end of the planning period, and it is supported by increasing amounts of BESS. In Resource Plan A, the increasing RPS is supported by biodiesel, including biodiesel conversion, which is at a lower cost, and generally comes in earlier in the planning period. This is why, when all options were available, PLEXOS developed the Resource Plan A expansion plan, at a lower cost of $0.5 billion (1.2%), compared to Resource Plan H. PLEXOS's optimization algorithms are seeking the lowest cost alternative.

8.2.19 PVRR Test with Alternative WACC Values

LUMA's base case value for the PREPA weighted average cost of capital (WACC) used in the IRP is 8%. However, since PREPA is in a financial situation that makes it difficult to forecast a long-term cost of capital with any confidence, LUMA chose to assess what it believes to be a plausible range of potential WACC for the IRP. LUMA tested the results of the PVRR using WACC values of 4%, 5%, 6%, 7% and 8%. The results using the different WACC values to calculate the PVRR, under base load conditions, are shown in a color coded Table 97, where green indicates the lower cost performance in each column for a given WACC, red indicates the higher costs and yellow indicates a cost in the middle of the range. Only the resource plans that were modeled under the base case load conditions are shown in the table. As can be seen with results, changing the WACC value has no impact on the relative ranking of the PVRR values in each column. Resource Plan Hybrid A with ASAP Phase 2 BESS as optional and with the battery efficiency corrected offers the least cost alternative, under the base case load conditions.

Table 97: PVRR of Resource Plans Calculated with Different WACC Values

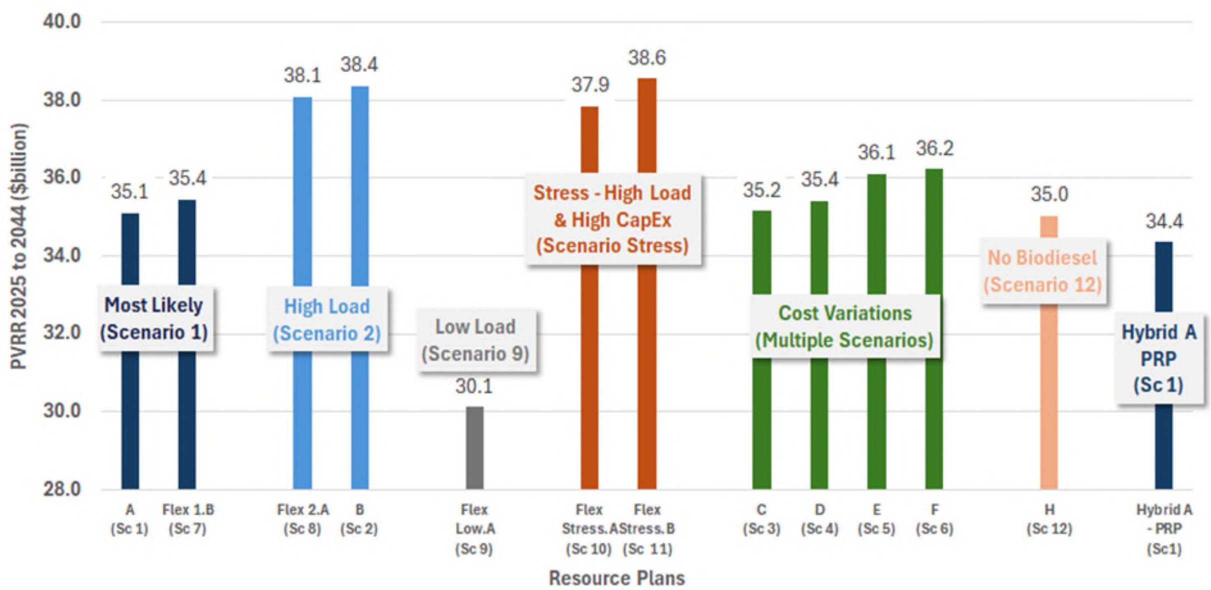
Resource Plan	Scenario	Load	Costs	Biodiesel Available	PVRR WACC 8% ($B)	PVRR WACC 7% ($B)	PVRR WACC 6% ($B)	PVRR WACC 5% ($B)	PVRR WACC 4% ($B)
Hybrid A - PRP	Scenario 1	Base	Base	Yes	34.4	37.6	41.3	45.6	50.5
Core A	Scenario 1	Base	Base	Yes	35.1	38.5	42.3	46.7	51.7
Core B	Scenario 7	Base	Base	Yes	35.4	38.8	42.6	47.0	52.1
Core C	Scenario 3	Base	High V2	Yes	35.2	38.5	42.3	46.7	51.7
Core D	Scenario 4	Base	High V3	Yes	35.4	38.8	42.6	47.1	52.1
Core E	Scenario 5	Base	High V4	Yes	36.1	39.5	43.4	47.8	52.9
Core F	Scenario 6	Base	High V5	Yes	36.2	39.7	43.6	48.0	53.2
Core H	Scenario 12	Base	Base	No	35.0	38.4	42.2	46.6	51.6

8.2.20 Development of New Resource Plan Hybrid A – The PRP

Based on its assessment of the modeling results for the Primary 12 Scenarios and the additional sensitivity analysis conducted on Resource Plans A and H, LUMA hypothesized that a new resource plan that incorporated the findings of the sensitivity runs, ASAP Phase 2 as optional and BESS efficiencies, was worth developing and analyzing. The resource plan that resulted from this modeling was designated Resource Plan Hybrid A (i.e., a hybrid or modified version of the original Core A Resource plan). The PVRR of Hybrid A resource plan yielded a resource plan with a PVRR of $34.4 billion, or 0.8% lower than the results of Core A, and improved reliability (EUE).

As discussed further in this Section and Section 8.0, LUMA ultimately selected Resource Plan Hybrid A as its Preferred Resource Plan (PRP). Figure 78 illustrates the Hybrid A Resource Plan on the same graph as the Resource Plans Resulting from the 12 Primary Scenarios.

Figure 78: 20-Year PVRR for Resource Plans Resulting from the 12 Primary Scenarios and Resource Plan Hybrid A



8.2.21 Performance Indicator Results

Each of the core Resource Plans were then assessed against the objectives and performance indicators included in the IRP Scorecard which was created with the input of stakeholders that participated in the SETPR meetings held around the Island. The performance indicators incorporated the PVRR results from the Flexibility Analysis described above and other performance indicators.

To assess the relative performance of multiple alternative resource plans and to document the basis of the assessment in the 2025 IRP filing, LUMA used the PVRR quantitative values as the primary performance indicator in comparing the different candidate Resource Plans and the remaining indicators were shown as numeric values where appropriate. The overall comparison of the indicators used a color-coded matrix, or what is commonly referred to as a “heat map,” to display the results in a simple color-coding that reflects the relative performance of each Resource Plan for each of the performance indicators. [152]

The color-coding visually serves to illustrate the relative results of the quantitative indicators of results of individual objectives, facilitates the focus on the resource plans that achieve favorable results at the least cost, and shows how each Resource Plan compares to the objectives of the 2025 IRP.

Table 98 and Table 99 show the results based on the objectives assigned to the scenarios. The color-coding matrix shows green as Low or as the most favorable, yellow as Medium, and red as High or least favorable.

[152] Id.

Table 98: Resource Plan Indicators Results- Scorecard Part 1[153]

Portfolio / Scenario	Environment				Affordability (Costs)				Compliance	Diversity of Generation				
	Avg CO2eq- 2025 to 2044 (tons/GWh)	Avg CO2eq- 2044 (tons/GWh)	Acres of Land Used	Year last heavy fuel oil unit operates	PVRR for source scenario ($B)	LCOE ($/kWh) 5-year 2025 to 2029	LCOE ($/kWh) 10- year 2025 to 2034	LCOE ($/kWh) 20-year 2025 to 2044	% RPS Achieved in 2044 (67% was Target)	Fossil energy in 2044 (%)	Solar energy in 2044 (including DPV) (%)	Biodiesel energy in 2044 (%)	Wind energy in 2044 (%)	Other energy sources in 2044 (%)
PRP / Scenario 1	360	164	6,030	2032	34.355	0.183	0.193	0.209	67%	44%	31%	22%	2%	1%
A / Scenario 1	354	144	6,030	2032	35.106	0.183	0.195	0.212	67%	43%	32%	22%	2%	1%
B / Scenario 2	359	168	6,030	2031	38.366	0.181	0.195	0.209	67%	43%	26%	28%	1%	1%
C / Scenario 3	357	162	6,030	2032	35.150	0.183	0.196	0.212	67%	43%	32%	22%	2%	1%
D / Scenario 4	357	161	6,030	2032	35.406	0.183	0.197	0.214	67%	43%	32%	22%	2%	1%
E / Scenario 5	358	160	6,030	2032	36.103	0.191	0.203	0.218	67%	43%	32%	22%	2%	1%
F / Scenario 6	355	160	6,030	2032	36.228	0.191	0.204	0.219	67%	43%	32%	22%	2%	1%
1.B / Scenario 7	346	161	6,030	2031	35.443	0.184	0.200	0.214	67%	44%	32%	22%	2%	1%
2.A / Scenario 8	362	169	6,030	2034	38.089	0.181	0.193	0.208	67%	44%	26%	28%	1%	1%
Low.A / Scenario 9	339	136	6,030	2031	30.117	0.189	0.202	0.215	67%	43%	50%	2%	3%	1%
Stress.A / Scenario 10	367	168	6,030	2034	37.855	0.181	0.191	0.206	67%	43%	26%	28%	1%	1%
Stress.B / Scenario 11	359	167	6,030	2031	38.552	0.181	0.195	0.210	67%	44%	26%	28%	1%	1%
H / Scenario 12	354	141	71,955	2034	35.028	0.183	0.194	0.211	71%	44%	40%	0%	15%	1%

Low - Better
Medium
High

High - Better
Medium
Low

[153] The acres of land used are based on 7 acres/MW for solar PV farms and 75 acres/MW for wind farm developments based on NREL's Tribal Options Analysis Rules of Thumb: Solar, Wind, and Biomass, June 2019 (https://www.energy.gov/sites/prod/files/2019/05/f63/gagne-rule-thumb-ppt.pdf). Only Portfolio H added additional incremental wind. The reader should note wind farm developments often preserve the ability to use most of the windfarm land. Where 75 MW/acre represents the average of the range of total land requirements for wind farms, only about 1 acre/MW is considered permanent land requirement for the foundation and immediate surroundings of the wind turbines.

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Table 99: Resource Plan Indicators Results- Scorecard Part 2

Portfolio / Scenario	System Reliability and Resiliency			System Reliability and Resiliency								DBESS control (%)
	Year 0.1/year LOLE achieved & sustained	Total LOLP Hours (2025 to 2044)	% Annual Energy from DER (2044)	Year 2044 %TPA Peak Load (MW) at system peak hour* that is served by internal MW capacity in TPA (includes utility scale generation, UBESS, DR & CHP)								
				San Juan	Bayamon	Arecibo	Mayaguez	Ponce OE	Ponce ES	Caguas	Carolina	
PRP / Scenario 1	2032	422	20%	223%	10%	31%	3%	310%	173%	29%	8%	25%
A / Scenario 1	2032	417	20%	257%	-2%	97%	4%	241%	103%	26%	10%	25%
B / Scenario 2	2030	1291	17%	218%	3%	91%	13%	352%	120%	19%	24%	25%
C / Scenario 3	2039	404	20%	156%	2%	77%	6%	423%	72%	66%	38%	25%
D / Scenario 4	2028	398	20%	222%	-2%	47%	15%	280%	143%	40%	34%	25%
E / Scenario 5	2034	419	20%	230%	-2%	42%	6%	314%	133%	39%	18%	25%
F / Scenario 6	2033	407	20%	230%	3%	93%	0%	310%	85%	36%	8%	25%
1.B / Scenario 7	2028	399	20%	181%	17%	34%	4%	426%	99%	51%	18%	25%
2.A / Scenario 8	2030	1292	17%	195%	19%	19%	1%	475%	130%	26%	89%	25%
Low.A / Scenario 9	2036	130	28%	166%	6%	75%	5%	349%	109%	72%	14%	25%
Stress.A / Scenario 10	2028	398	20%	229%	14%	82%	40%	359%	46%	34%	25%	25%
Stress.B / Scenario 11	2030	1292	17%	242%	19%	46%	16%	348%	113%	25%	18%	25%
H / Scenario 12	2034	398	17%	183%	2%	83%	6%	343%	112%	41%	35%	25%

Low - Better
Medium
High

High - Better
Medium
Low

8.2.22 Selection of the Preferred Resource Plan

Based on cumulative insight gained from stakeholders in the SETPR meetings, modeling of resource options and the results of the IRP Scorecard results, with PVRR providing the primary selection indicator, LUMA recommends Resource Plan Hybrid A as the PRP. This proposal represents the lowest PVRR results under the most likely assumptions for costs and loads. However, LUMA also recommends that all future solicitations for generation purchases, or long-term purchased power agreements include:

- Options for biodiesel fueled generators, solar and wind technology options with the final technology selection based on a technology agnostic assessment of the bid prices, technical and commercial elements of the proposals, and land use considerations.
- A provision that any new thermal generation should be designed to use either LNG, diesel, diesel blended with biodiesel or 100% biodiesel.

8.3 Detailed Results for Preferred Resource Plan

8.3.1 Preferred Resource Plan - Resource Plan Hybrid A

The PRP builds upon Scenario 1, which serves as its foundational reference. Scenario 1 incorporates all defining characteristics of the “Base” scenarios, representing the most probable trajectory of key planning assumptions.

A key distinction between the PRP and Scenario 1 lies in the treatment of the ASAP BESS Phase 2 projects. While Scenario 1 assumes these projects as fixed components of the resource plan, the PRP considers them optional. This approach allows for greater flexibility in resource selection and supports a more adaptive planning framework.

Additionally, the PRP refines the battery energy storage system (BESS) efficiency assumptions used in Scenario 1. Whereas Scenario 1 applies a generic efficiency value, the PRP incorporates updated and more accurate performance expectations, enhancing the reliability of modeling outcomes.

Annual Capacity Contribution by Resource

Table 100 and Table 101 present the capacity of energy resource additions and retirements that occur under the Preferred Resource Plan. Combined, the information on those tables shows significant activity with additions and retirements over the planning period. A total of 1,622 MW of new thermal generation is added in the PRP (including the 478 MW Energiza unit but not including the 800 MW of emergency generation) of which 1069 MW, or 66% of the new thermal generation is either built to initially burn renewable biodiesel fuel or is converted to biodiesel prior by 2044. In addition, three transmission lines of 230 kW were added in the PRP as a component of the optimal expansion plan. The three transmission lines are added in the year 2030. The lines added are a Carolina-San Juan 230 kW line, a Mayagüez-Ponce OE 230 kV line and a Ponce ES-Caguas 230kV line.

Table 100: Capacity Addition Summary (MW) for Preferred Resource Plan

Units	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total

[redacted]

Units	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
[redacted]																					

Table 101: Preferred Resource Plan Resource Capacity Retirements (MW)

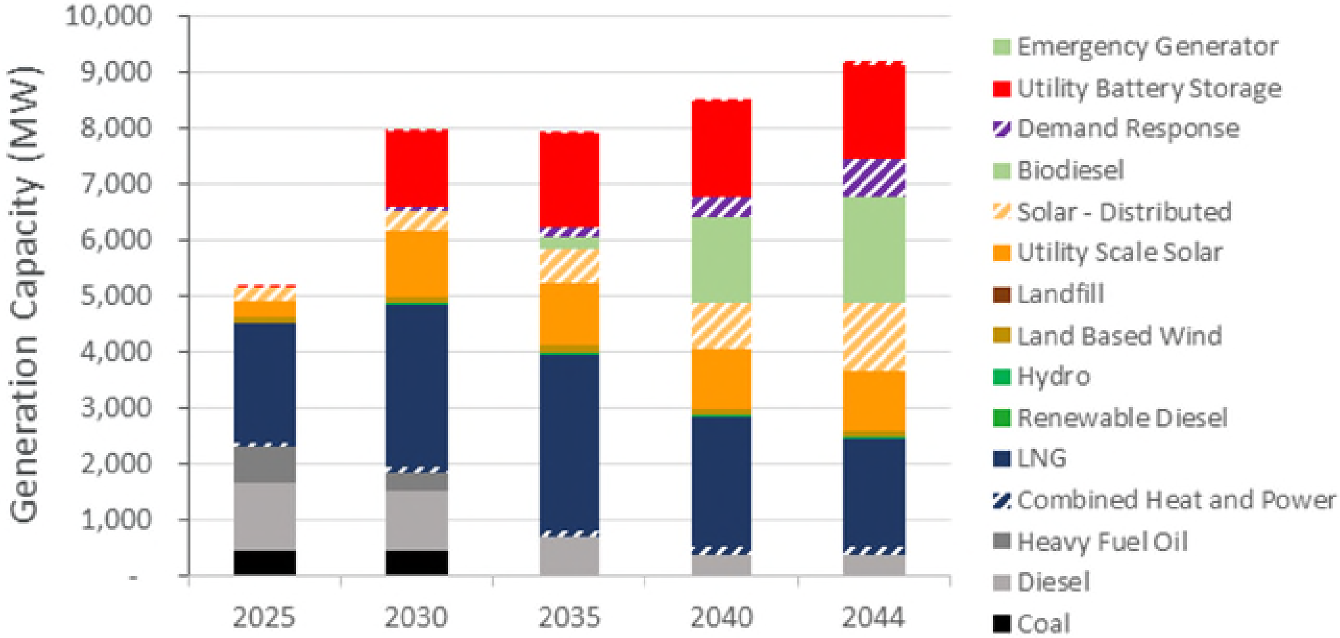
Units	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
[redacted]																					

154 [redacted]

Units	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Total
[redacted]																					

[156] Unit conversions from gas to biodiesel are shown as retirements in resource model outputs and workpapers (i.e., since they are retired from natural gas fuel service when converted to biodiesel and then immediately enter service as a biodiesel generator) but fuel conversions have been excluded from this table of retirements. With the agreement of the Energy Bureau Consultant, Aguirre ST 1 & 2 which burn heavy fuel oil were considered out of the service for the entirety of this IRP study period (2025 to 2044). Aguirre ST 1 & 2 if operable, would presumably be retired scheduled for official retirement during the IRP study period.

Figure 79: Preferred Resource Plan Installed Capacity (MW)



Energy Production by Fuel or Resource

Table 102 details on the source of energy production by fuel type and resource. There is notable growth in energy generation by biodiesel contributing to progress toward the RPS target. The table also shows the contribution of various renewable generation sources to the overall energy production mix.

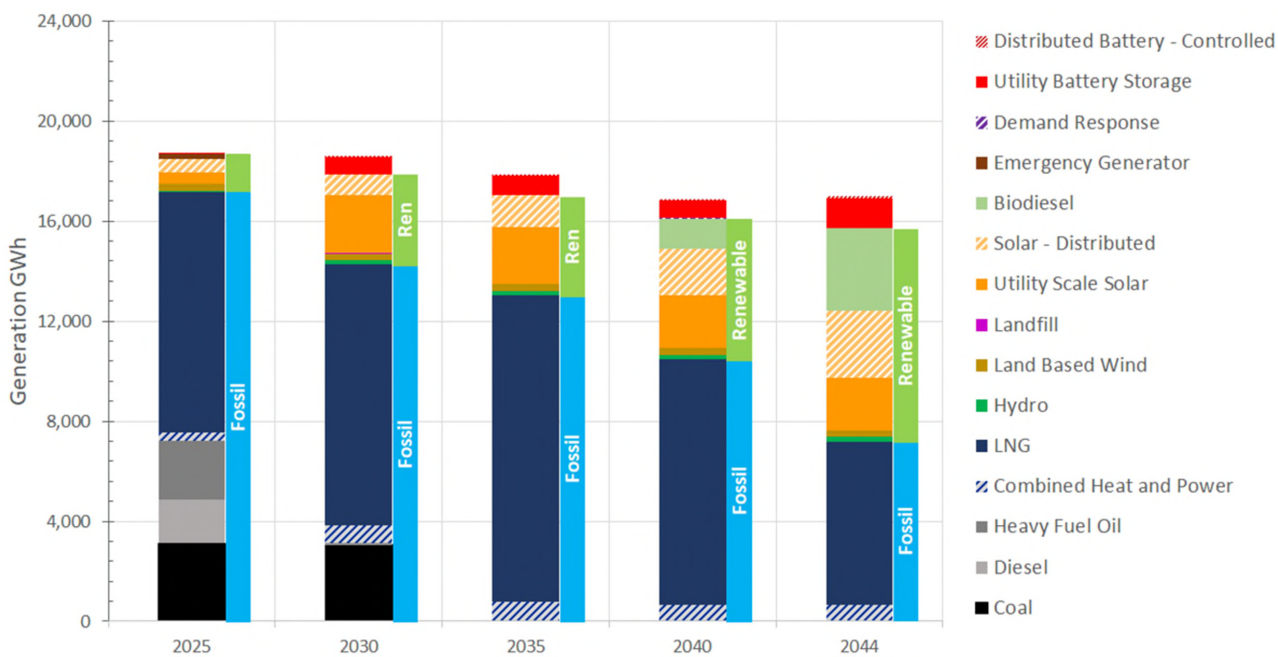
Table 102: Preferred Resource Plan Energy Production by Fuel or Resource (GWh)

Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
[redacted]																				

Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044

[redacted]

Figure 80: Preferred Resource Plan Energy Generation by Resource (GWh)



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Annual Emissions by Resource

Table 103 below showcases the annual emissions by resource. The table does not show hydro, solar PV, demand response, wind and batteries, as there are no emissions associated with energy generation by these resources.

Table 103: Preferred Resource Plan Annual Emissions by fuel (thousand tons CO2eq)

Fuel	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
[redacted]																				

Annual Fuel Consumption by Fuel Type

Table 104 below shows the annual fuel consumption by fuel type. The table does not show hydro, landfill, solar PV, demand response, wind and batteries, as there is no fuel consumption associated with them. In addition, the table does not show CHP fuel consumption as these systems are located behind the meter, acting as load modifiers. As such, they do not generate electricity for the grid and its fuel consumption would be out of scope for this study.

Table 104: Preferred Resource Plan Annual Fuel consumption by Fuel Type (BBtu)

Fuel	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
[redacted]																				

Cash-Flow Table (PVRR)

Table 105 shows the cost components of the PRP throughout each of the years of the planning period and the total PVRR needed to recover the PRP costs. It includes the production costs of the system each year, including fuel costs, fixed O&M costs, variable O&M costs, and costs associated with unit starts and shutdowns. Also listed are the fixed costs associated with the program costs for demand response programs, distributed BESS programs, and other unit additions. For each year, the total system cost in Table 105 equals the sum of the production and fixed costs.

Table 105: Preferred Resource Plan System Costs and PVRR

Cost	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Fuel Cost ($000)	2108	1416	1277	1074	1080	1075	1083	1075	1134	1152	1166	1153	1158	1176	1281	1360	1465	1516	1571	1648
VO&M Cost ($000)	251	375	427	420	421	422	423	423	405	403	400	385	358	350	351	362	354	340	338	342
FO&M Cost ($000)	709	990	1142	1389	1376	1381	1491	1506	1331	1356	1376	1378	1382	1369	1362	1378	1405	1427	1458	1493
Start & Shutdown Cost ($000)	16	9	7	4	5	5	5	5	4	4	4	4	4	3	5	6	6	6	5	7
Variable Production Costs ($000)	2376	1801	1711	1498	1506	1503	1511	1503	1543	1559	1569	1541	1519	1530	1637	1728	1825	1863	1913	1996
Total Production Cost ($000)	3084	2790	2853	2886	2882	2884	3002	3009	2874	2915	2945	2919	2902	2899	2999	3106	3230	3290	3371	3489
Demand Response Programs Levelized Costs ($000)	0	0	0	0	2	4	8	11	14	16	19	24	31	42	57	72	91	115	138	150
DBESS Program Cost ($000)	0	0	1	2	3	5	6	7	8	9	10	11	13	15	17	20	21	23	25	27
Unit Additions Annualized Capital Costs ($000) (includes fixed decisions annual costs)	76	245	500	657	750	753	789	793	903	907	912	916	1041	1045	1049	1053	1058	1062	1067	1071
Unit Additions Capital Costs ($000) (for variable unit additions)	0	0	0	0	0	145	308	0	1020	0	5	0	1155	0	0	0	0	0	0	0

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Cost	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Total System Cost ($000) (includes EE program costs)	3287	3142	3422	3620	3691	3704	3864	3881	3862	3883	3921	3870	3987	4000	4122	4251	4622	4522	4626	4760
Present Value Revenue Requirement (PVRR) ($000)	2818	5313	7828	10292	12618	14779	16867	18808	20597	22262	23819	25242	26600	27861	29064	30213	31370	32417	33410	34356
Average Production Cost Load Based, $/kWh	0.166	0.153	0.157	0.160	0.161	0.162	0.170	0.173	0.167	0.171	0.174	0.175	0.176	0.178	0.186	0.194	0.203	0.209	0.216	0.225
Average System Cost Load Based, $/kWh	0.177	0.173	0.189	0.201	0.206	0.209	0.219	0.223	0.224	0.227	0.232	0.232	0.242	0.246	0.256	0.266	0.290	0.288	0.296	0.307

*Total system costs are not equivalent to tariffs.

Section 9: Caveats and Limitations

9.0 Caveats and Limitations

9.1 Caveats to Flexibility Analysis Design

9.1.1 Time Constraints Limited Stakeholder Involvement and Scope of Revised Analysis

LUMA had limited time available to complete revisions to the 2025 IRP that addressed the changes in the plan necessitated by the passing of Act 1 of 2025, which amended Act 17-2019, known as the Puerto Rico Public Energy Policy Act. Both LUMA and the Energy Bureau aimed to avoid unnecessary delays in filing the IRP. However, additional time was needed to incorporate the impacts of Act 1 and other project updates, some of which might significantly affect the results. The list of 12 scenarios ultimately pursued represented a combination of the two individual lists of scenarios that LUMA and the Energy Bureau's consultant viewed as the minimum list of Scenarios that could be completed within the timeframe and that could form the basis of a robust and rigorous analysis, as is required to select a preferred resource plan (PRP). The number of scenarios and the variation in the scenario characteristic was necessarily limited due to the constraints on time. The shortened modeling timeframe also did not allow LUMA sufficient time to seek input from stakeholders for the revised scenarios, and the interim results, which had been a key element of LUMA's activities for the originally planned 2025 IRP filing. While the analysis time frame and modeling scope was necessarily constrained for this report, LUMA believes the analysis and recommendations described in this report still fulfill the intent and requirements of Regulation 9021.

9.2 Caveats to Assumptions

9.2.1 Liquid Natural Gas Infrastructure

The Genera natural gas-fueled generation at the San Juan and Costa Sur plants is served by existing LNG import and delivery infrastructure. Genera's fleet already includes natural gas-fired generation located in Palo Seco that is supplied by trucked LNG that originates from the San Juan LNG delivery location and is then stored onsite at Palo Seco.

For the purposes of the 2025 IRP, LUMA has assumed that new combined cycle units, or any natural gas-fueled units that are expected to operate at capacity factors approximating intermediate to base load levels will only be located at sites within the Transmission Planning Areas (TPAs) of existing LNG delivery infrastructure, specifically San Juan and Costa Sur. New natural gas generation expected to operate as peaking units, such as simple cycle gas turbines and RICE units, may be located in any TPA, however, their fuel supply is assumed to be limited to trucked LNG. San Juan is considered the sole source of LNG for all trucked deliveries in the 2025 IRP. Nonetheless, the development of an additional or alternate trucked LNG filling station at Costa Sur remains an option as do any new LNG import facilities that may be developed in the future.

To expand the potential locations of new gas fueled combined cycle units, LUMA evaluated but ultimately dismissed the potential of adding new LNG import locations in additional TPAs, building overland pipelines to deliver gas from import locations to remote plants in other TPAs, or trucking LNG to those locations. Multiple parties have proposed expanding future sea-borne imports of LNG to other locations including Mayagüez and Aguirre. Should these or other new import locations be approved and implemented, the location of future natural gas fueled intermediate, or baseload generation could expand to include any new import locations. However, LUMA did not include any of the proposed new import locations in the 2025 IRP since there is still significant uncertainty regarding whether these proposals will be successfully developed. The same is true for gas pipelines which have been proposed but never approved due in part due to public and regulatory concerns. LUMA judged the uncertainty of success too high to include any new gas pipelines that span between TPAs, which could have expanded the location of future natural gas fueled intermediate or baseload generation. Finally, LUMA estimated the quantities of LNG trucks that would be required to service a large, combined cycle unit operating at reasonable capacity factors. The number of required daily LNG fuel truck deliveries was judged by LUMA too high and likely to face strong opposition from multiple stakeholders. Based on this analysis of the number of required daily LNG fuel trucks daily truck deliveries required to service a combined cycle plant, LUMA limited the location of new combined cycles to the two TPAs noted.

9.2.2 Hydroelectric Generation Increases

LUMA has assumed in all scenarios that the contract for purchased power from the EcoEléctrica plant can be negotiated and extended beyond its current 2032 end date. The EcoEléctrica plant remains a critical generation contributor to Puerto Rico. LUMA believes its continued operation is expected to be important to LUMA's goal of improving the near-term reliability of Puerto Rico's electric service. While additional analysis with and without the EcoEléctrica plant would be useful, LUMA believes it doubtful that an alternative resource could replace the energy from EcoEléctrica's at a lower cost.

In June 2021 a "Feasibility Study for Improvements to Hydro Electric System" report was completed by an independent consultant to assess the PREPA hydroelectric generation facilities and form recommendations regarding their condition and the potential repair and improvement to the facilities. Based on this study's findings, PREPA HydroCo developed a plan to repair and refurbish a number of its hydroelectric facilities. On October 11, 2023, in Docket NEPR-MI-2021-0002, the Energy Bureau approved projects totaling $320,790,000 for PREPA repair and refurbishment of these hydroelectric facilities. LUMA's understanding was that these projects were to be funded by FEMA funds available to PREPA. Based on this history, LUMA included in its Fixed Decisions for all Scenarios the assumption that PREPA HydroCo will complete refurbishment of its existing hydroelectric facilities by 2026 that result in an increase to the generation capacity by 38 MW or more. The Hydro capacity assumption used in the IRP for the year 2025 is 20 MW, combined with the forecasted increase of 38 MW brings the capacity to a total of 58 MW in 2026 and the following years. LUMA chose to include in the 2025 IRP only a portion of the potential 90 to 120 MW potential of the facilities. LUMA believes the ability to deliver this additional capacity in the timeframe forecasted is uncertain. LUMA recommends that the capacity and energy forecasted for these projects be removed in future modeling until PREPA provides additional information for these projects that would support a confident forecast that project funding is likely and what capacity, energy and operation date can be expected for these projects.

9.3 Caveats to Known Data Issues

9.3.1 Battery Charging and Discharging Efficiency

As noted above, in August 2025, while LUMA was conducting PLEXOS modeling of the 12 Primary scenarios and performing reviewing of the results, LUMA became aware that both the UBESS and the DBESS round trip efficiency (i.e., the combined effect of the charge and discharge efficiencies) values had been entered into PLEXOS at unrealistically high levels. The UBESS round trip efficiency was set at 90% and the DBESS was set at 100%. Unfortunately, by the time the error in the UBESS and DBESS efficiencies data was identified, the majority of the planned PLEXOS modeling had been completed with the erroneous efficiency data. LUMA determined there was insufficient time remaining to revise and remodel the numerous PLEXOS runs that had been completed prior to the required October 17, 2025, filing for the 2025 IRP report. Using a corrected 85% round trip efficiency from the 2024 National Renewable Energy Laboratory (NREL) 2024 Annual Technology Baseline[157] for both the UBESS and DBESS, LUMA reran the PLEXOS for Scenario 1 (most likely conditions), Resource Plan A, to compare it to the results prior to the correction and determine the impact of the BESS round trip efficiency error. The runs with and without the BESS efficiency correction yielded only 0.1% difference in the PVRR values through 2044.

LUMA then performed the same analysis for the Scenario 12 (no biodiesel) comparing the results with and without the BESS efficiency correction and found once again there was only a 0.1% difference in the PVRR values through 2044.

Based on the small impact to the PVRR from the battery efficiency correction, LUMA judged the difference in results to be too small to impact the ranking of resource plans resulting from the 12 primary scenarios, LUMA's flex analysis. In addition, the battery efficiency was corrected in the analysis and results of the PRP, Resource Plan Hybrid A.

9.3.2 ASAP Phase 2 BESS as Fixed versus Optional Additions

Also as noted above, the ASAP Phase 2 BESS additions were included as a fixed decision for all scenarios with each of the Phase 2 projects installed in December 2026. However, LUMA noted that very few additional batteries were being installed in the resource plans for which the modeling had been completed by early August 2025.

To assess whether all of the ASAP BESS Phase 2 capacity was required and if it was required in 2026, LUMA ran sensitivity tests for the resource plans resulting from Scenario 1 (Resource Plan A) and Scenario 12 (Resource Plan H) by changing the ASAP BESS Phase 2 projects from fixed to an optional addition. This sensitivity design allowed PLEXOS to decide how much Phase 2 battery capacity was required and when it was required based on economics and reliability criteria in PLEXOS. The results of sensitivity runs for both A and H indicated the full ASAP Phase 2 BESS capacity was required but that the installation could be delayed 3 or more years depending on the scenario. This delay of the projects results in a 1.3% reduction in PVRR cost for Resource Plan A with the ASAP Phase 2 as optional and the correction of the round-trip efficiency of the batteries and 0.3% reduction for Resource Plan H. Ultimately, changing the ASAP, Phase 2 BESS projects to an optional decision was adopted as an element of the revised assumptions for the PRP, Resource Plan Hybrid A.

9.3.3 Fixed Operating Cost Correction

Late in the modeling process LUMA became aware of what it believes is a bug in the modeling software that created an error resulting in FOM values for the AES 1, AES 2, and EcoEléctrica plants that were higher than intended. While the correct FOM values were properly entered into the modeling software, the software used an earlier input for these plants, which should have been ignored. Since the bug in the software involved FOM costs that did not vary across the scenarios, the resulting error in the PVRR was identical for all resource plans. Using the corrected FOM data for the AES and EcoEléctrica plants yield a

[157] NREL (National Renewable Energy Laboratory). 2024. 2024 Annual Technology Baseline, Version 3. Golden, CO: National Renewable Energy Laboratory. The roundtrip efficiency of the NREL data for the utility, commercial and residential batteries are all 85%.

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reduction of $0.47 billion in the PVRR of all scenarios. As a fixed cost change that would have been identical in all scenarios, the FOM correction, had it been entered prior to the modeling, would not have impacted the modeling results or the relative PVRR ranking of the resource plans. In addition, LUMA had insufficient time remaining prior to the required filing of the 2025 IRP to remodel the scenarios with the corrected FOM. Therefore, LUMA chose to enter the FOM correction to the summary spreadsheets that were used to calculate the PVRR and present other results. The PVRR results contained in the report include the correction to the PVRR related to the FOM software bug.

9.3.4 2027 Controlled DBESS Retired Capacity

Again, late in the modeling process LUMA became aware of a small error in the capacity for the Controlled DBESS. The numbers for 2027, and all years after, are correct. However, for 2024 through 2026, instead of the intended values of 0MW, an earlier set of inputs (e.g., 6MW total for 2026), were used. Hence, in the transition from 2026 to 2027, there was an unintended reduction of 3MW in DBESS. As the incorrect inputs are in the first 3 years of the study period, during which time PLEXOS does not have the flexibility to make changes (e.g., add new generation or transmission, retire generation), the numbers are small relative to the size of the system, and the issue was discovered after several of the simulations had been completed, it has not been corrected. The simulations were checked to ensure they all had the same issue, and steps were taken to ensure the issue persists. This ensures that comparisons between scenarios are done correctly. In other words, the relative differences between scenarios should not be impacted by this issue.

9.3.5 Caveats to Additional Regulation 9021 Requirements

Regulation 9021, Subsection 2.03(F)(1)(b)(viii) requires new generation meet the requirement for "high efficiency" generation, as that term is defined by the Energy Bureau, in accordance with Section 6.29(a) of Act 57. This regulation was interpreted by the Energy Commission in its November 16, 2021 Resolution in case CEPR-MI-2016-0001 and requires new units be able to generate at a cost of $0.100/kWh, or less, adjusted to 2018$ and must have average annual CO^2 emission rates of 1,433 lbs/MWh for natural gas fueled units. As shown in Table 106, the new 7F.05 1x1 combined cycle recommended in the PRP for installation meets that generation efficiency and CO^2 emission requirement for each year of its recommended operation fueled with natural gas, from 2033 to 2039, the three natural gas fueled LM2500 simple cycle units do not meet the generation efficiency require (only the first 5 years of operation for the LM2500 units are shown). All the new units meet the CO^2 emission limits stated in the requirements.

Table 106: High Efficiency Compliance Check for Average $/kWh Cost

Unit	Year	Generation (GWh)	Capacity (Max or Rated) (MW)	Capacity Factor (%)	Average $/kWh - Nominal$	Average $/kWh Adjusted to 2018$ (based on FOMB inflation rates)	CO^2 Emission lbs/MWh
7F.05 1x1_S Juan	2033	3,047	373	93	$0.13	$0.10	821
7F.05 1x1_S Juan	2034	2,969	373	91	$0.14	$0.10	800
7F.05 1x1_S Juan	2035	2,982	373	91	$0.14	$0.10	803
7F.05 1x1_S Juan	2036	3,020	373	92	$0.14	$0.10	812
7F.05 1x1_S Juan	2037	3,029	373	93	$0.14	$0.10	816

Unit	Year	Generation (GWh)	Capacity (Max or Rated) (MW)	Capacity Factor (%)	Average $/kWh - Nominal$	Average $/kWh Adjusted to 2018$ (based on FOMB inflation rates)	CO^2 Emission lbs/MWh
7F.05 1x1_S Juan	2038	2,991	373	91	$0.15	$0.10	806
7F.05 1x1_S Juan	2039	2,888	373	88	$0.15	$0.10	779
LM2500 1x0_Arecibo	2031	41	35	14	$0.44	$0.34	1,189
LM2500 1x0_Arecibo	2032	37	35	12	$0.48	$0.37	1,186
LM2500 1x0_Arecibo	2033	27	35	9	$0.60	$0.45	1,194
LM2500 1x0_Arecibo	2034	26	35	9	$0.63	$0.47	1,190
LM2500 1x0_Arecibo	2035	31	35	10	$0.55	$0.40	1,195
LM2500 1x0_Ponce OE	2031	66	35	22	$0.32	$0.25	1,190
LM2500 1x0_Ponce OE	2032	62	35	20	$0.33	$0.26	1,185
LM2500 1x0_Ponce OE	2033	53	35	17	$0.37	$0.28	1,190
LM2500 1x0_Ponce OE	2034	47	35	15	$0.41	$0.30	1,192
LM2500 1x0_Ponce OE	2035	46	35	15	$0.42	$0.30	1,192
LM2500 1x0_S Juan	2031	73	35	24	$0.30	$0.23	1,187
LM2500 1x0_S Juan	2032	62	35	21	$0.33	$0.25	1,185
LM2500 1x0_S Juan	2033	48	35	16	$0.40	$0.30	1,190
LM2500 1x0_S Juan	2034	47	35	15	$0.41	$0.30	1,186
LM2500 1x0_S Juan	2035	49	35	16	$0.40	$0.29	1,189

In the PRP, this combined cycle unit is converted to a biodiesel/diesel fuel blend in 2040, to contribute to the RPS requirements, after which, with the higher cost of the biofuel blend would exceed the $0.100/kWh efficiency requirement. The three 35 MW, LM 2500 simple cycle units recommend for installation in 2031 cannot meet the $0.100/kWh generation efficiency requirement even if they were operated at a 90% capacity factor.

Subsection 2.03(F)(4)(a) of Regulation 9021 requires a description of the anticipated use of the storage additions, whether to reduce renewable curtailment, provide voltage and frequency stability and/or regulation, or other purposes. The planned 2028 addition of the four 25 MW, 4-hour batteries (referred to as Regulation Only BESS, or 4x25 BESS) are planned for only system regulation under normal operation. The remaining battery additions will all serve as a multifunction role to reduce renewable curtailments, provide energy shift (storing energy during peak solar production and discharging to meet demand at other times during the day), regulation service and other services as needed.

9.4 Conclusion

Following the analysis of Resource Plans resulting from the 12 Primary Scenarios and the subsequent analysis of Resource Plans A and H, LUMA created a hybrid of the original Scenario 1 which corrected the BESS efficiencies and changed the ASAP Phase 2 batteries from fixed additions to optional additions. The resulting Resource Plan was designated Hybrid A and its PVRR results, and other performance criteria led LUMA to select it as the Preferred Resource Plan (PRP).

Section 10: Action Plan

10.0 Action Plan

10.1 Action Plan Overview

This section of the report is intended to summarize key actions that LUMA recommends take place in the first five years of the 2025 IRP. Since this IRP is being filed near the end of 2025, LUMA has included plans for the six years 2025 to 2030. LUMA has included recommended actions starting in 2025 through December 2030 to incorporate recommended actions associated with the ongoing progression of the fixed decision projects that are not dependent on the approval of the 2025 IRP.

10.1.1 Recommended Energy Resource Additions

Table107 below summarizes the energy resource additions for 2025 to 2030.

Table107: Preferred Resource Plan Energy Resource Additions for 2025 to 2030 (MW)

Energy Resource	2025	2026	2027	2028	2029	2030	Grand Total
[redacted]							

As shown in Table107, almost 5 GW of energy resources are planned for installation by 2031.

LUMA must perform many activities to successfully enable the interconnection, and to a lesser extent, implement the capacity that aligns with the PRP. However, much of the success of these projects will be largely outside of LUMA's control. A summary of the energy resource categories and their respective total additions through 2030 is shown in Table108 below. An analysis of the data in Table108 shows that LUMA's PRP recommendations represent only 1% coming from customer programs. A summary of the expenditures through 2030 includes:

- 9%, or 378 MW are distributed generation additions for which the capacity and dates of installation will be driven solely by customer decisions
- 90%, or 2,565 MW are projects based on fixed decisions for the addition of generation and batteries prior to LUMA's filing of the 2025 IRP Report
- 1%, or 56 MW of forecasted customer programs will be implemented by LUMA, if this plan is approved by the Energy Bureau

Table108: Preferred Resource Plan Energy Resource Additions By Category in First 5-Years (MW)

Energy Resource	Grand Total 2025 to 2030	Percent	Summary of LUMA's Actions to Support Implementation
Distributed Generation	378	9%	Process and assess interconnection applications, and continue upgrades to distribution system to enable increased distributed generation
Fixed Decision Generation	2,565	59%	Process and assess interconnection applications of interconnection applications, negotiation of interconnection agreements and implementation of any required transmission network upgrades.
Fixed Decision Batteries	1,365	31%	Process and assess interconnection applications interconnection applications, negotiation of interconnection agreements and implementation of any required transmission network upgrades.
PRP Customer Programs	56	1%	Design and administration of programs approved by the Energy Bureau
Grand Total	**4,364**	**100%**	

Most of the capacity and many of the project activities required to implement the projects listed in Table107 will neither be performed by LUMA nor will LUMA have control over when or if the activities are initiated and completed. Therefore, LUMA has focused its detailed action plan in Section 10.2 on recommended activities for LUMA and the Energy Bureau to best support and drive their timely and successful implementation.

In addition to the Energy Resource additions, the PRP includes three transmission link upgrades which will be needed to increase the transfer capacity between TPAs to accommodate the planned generation. The three transmission link upgrades include increasing the 230 kV transfer capacity between the following TPA links:

1. Carolina to San Juan
2. Mayaguez to Ponce OE

3. Ponce ES to Caguas

These transmission lines were identified as economically justified based on the results of the resource modeling software for the PRP. However, LUMA considers these upgrades to be initial recommendations that will be updated based on the ongoing PSSe analysis of the transmission impact of the PRP. The results of the PSSe analysis are to be filed with the Energy Bureau on November 21, 2025.

10.1.2 Recommended Energy Resource Retirements

The recommended retirements in the PRP are all contingent on the timely addition of the new resources recommended in Section 10.1.1. Table109 summarizes the recommended retirements in the PRP. The retirement of the 800 MW of Emergency Generators is dependent first on their addition prior to 2029 and on the addition and commercial operation of the Energiza CC unit shown in in Table108. The retirement of the seven 21 MW GT units is contingent on the planned addition of the New Genera Peaking Units identified in Table108. The retirement of Palo Seco 4 and San Juan 7 units should be dependent on future resource adequacy analysis indicating the system has sufficient capacity to provide a forecast of acceptable reliability results, as measured by LOLE, EUE or similar indicators.

Table109: Preferred Resource Plan Energy Resource Retirements for 2025 to 2030 (MW)

Energy Resource	2025	2026	2027	2028	2029	2030
[redacted]						

10.2 Action Plan Detail by Project

10.2.1 Distributed Generation

- **CHP** – LUMA must be able to make regular revisions to its planning forecasts, including for CHP. The utility consumption from customer-developed CHP, other forms of self-generation or plans for self-generation are an increasing element of uncertainty in LUMA's ability to forecast the usage and impact of these customers. LUMA recommends that the Energy Bureau establish reporting and interconnection requirements that would require all industrial customers and large commercial customers known to have, planning, or contemplating CHP or other large, distributed generation projects of any technology to report these activities to the Energy Bureau and LUMA to aid in the LUMA's planning processes.

- **DPV** – LUMA will continue to provide updates as required in existing dockets.

10.2.2 Fixed Decision Generation

- **PREPA HydroCo Repairs** – Consistent with the theme of making regular updates to forecasts, LUMA needs to know the status of the plans and activities for the repair and refurbishment of PREPA's hydroelectric facilities. To aid in that endeavor, LUMA recommends that the Energy Bureau request monthly updates from PREPA HydroCo on the status of its repair and refurbishment projects and that those updates also be provided to LUMA for use as an input to LUMA's regular planning processes.

- **Emergency Generators** – LUMA recommends the Energy Bureau obtain and distribute to LUMA monthly status reports on the emergency generators from the Puerto Rico Public-Private Partnership Authority's independent Third-Party Procurement Office (3PO) and PREPA until all the capacity is operating. Once operational, quarterly operating reports should be required until the capacity is removed from service.

- **Energiza Gas CC** – LUMA recommends the Energy Bureau obtain and distribute to LUMA monthly status reports from Energiza and PREPA until the project begins operations. The information will provide LUMA needed input to its regular planning processes.

- **New Genera Units** – LUMA recommends the Energy Bureau obtain and distribute to LUMA monthly status reports from Genera until the projects begin operations. The information will provide LUMA needed input to its regular planning processes.

- **Non-Tranche Solar** – LUMA recommends the Energy Bureau obtain and distribute to LUMA monthly status reports from Ciro1 and Xzerta until the projects begin operations. The information will provide LUMA needed input to its regular planning processes.

- **Solar Tranche 1 and 2** – LUMA recommends the Energy Bureau obtain and distribute to LUMA monthly status reports from all ongoing Tranche Solar project developers until the projects begin operations. The information will provide LUMA needed input to its regular planning processes.

10.2.3 Fixed Decision Batteries

- **ASAP Phase 1 BESS** – LUMA recommends the Energy Bureau obtain and distribute to LUMA monthly status reports from the individual resource providers until the projects begin operations. The information will provide LUMA needed input to its regular planning processes.

- **New Genera BESS Units** – LUMA recommends the Energy Bureau obtain and distribute to LUMA monthly status reports from Genera until the projects begin operations. The information will provide LUMA needed input to its regular planning processes.

- **Regulation 4x25 BESS** – LUMA will continue to provide updates as required in existing case NEPR-MI-2021-0002.

- **BESS Tranche 1, 2, and 4** – LUMA recommends the Energy Bureau obtain and distribute to LUMA monthly status reports from the individual resource providers until the projects begin operations. The information will provide LUMA needed input to its regular planning processes.

10.2.4 Preferred Resource Plan Customer Programs

- **Demand Response** – Assuming the Energy Bureau approves LUMA's action plan for economic demand response utilizing load reduction strategies and associated budgets by the start of FY2027 in Case No. NEPR-MI-2022-0001, LUMA will refine design, launch, and recruit for new economic demand response programs by the end of Q4 FY2027. LUMA also plans to monitor potential adverse impacts on customer enrollment due to market dynamics with LUMA's Emergency Load Reduction Program offering and to submit refined action plans to the Energy Bureau annually.

- **Demand Response and Controlled DBESS** – LUMA will continue to provide updates as required in existing dockets.

10.2.5 Preferred Resource Plan Action Plan Summary Table

Table110 provides a summary listing of the recommended action plan.

Table110: Action Plan Summary Table

Energy Resource	Frequency Of Update or Communication	Primary Responsibility	Stakeholders to be Informed
CHP	Bi-annual	Energy Bureau	LUMA
Hydro	Monthly	PREPA	LUMA, Energy Bureau
Emergency Generators	Monthly	PREPA	LUMA, Energy Bureau
Energiza Gas CC	Monthly	3PO	LUMA, Energy Bureau, P3A
New Genera Units	Biweekly	Genera	LUMA, Energy Bureau
Non-Tranche Solar	Monthly	Energy Bureau	LUMA, PREPA
Other projects	Monthly	Energy Bureau, PREPA or 3PO	LUMA
ASAP Phase 1	Biweekly - Stay	Energy Bureau	LUMA
ASAP Phase 2	Biweekly - Stay	Energy Bureau	LUMA
New Genera Batteries	Biweekly	Genera	LUMA, PREPA
BESS Tranche 1, 2 & 4	Biweekly	PREPA	Energy Bureau