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

IN RE: PUERTO RICO TEST FOR DEMAND RESPONSE AND ENERGY EFFICIENCY	**CASE NO:** NEPR-MI-2021-0009 **SUBJECT:** Avoided Cost Study for Application to Energy Efficiency Plan Cost-Effectiveness Evaluations.

RESOLUTION AND ORDER

I. Introduction

In this Resolution and Order, the Energy Bureau of the Public Service Regulatory Board of Puerto Rico ("Energy Bureau") issues its Avoided Cost Study for application to energy efficiency planning and analysis between now and when it can be updated to align with an approved updated Integrated Resource Plan in Case No. NEPR-AP-2023-0004[1]. The benefits addressed in this study include: (1) avoided energy generation costs, (2) avoided capacity costs, and (3) avoided greenhouse gas (GHG) emissions costs. Avoided environmental compliance costs and some of the avoided ancillary services are a component of the avoided energy generation costs and are thereby also included in this study.

II. Summary of Procedural History

A. Avoided Cost Study Initiation

On May 14, 2021, this Energy Bureau issued a Resolution and Order initiating the referenced proceeding to develop the Puerto Rico Benefit Cost Test ("PR Test") as required by the Energy Bureau's Regulation for Demand Response of December 21, 2020, Regulation 9246, and under the then Proposed Energy Efficiency Regulation issued by the Energy Bureau on April 22, 2021.[2] On August 13, 2021, the Energy Bureau issued a Resolution and Order informing that it was developing an avoided cost study to be used to develop values for the PR Test ("Avoided Cost Study").[3] The Energy Bureau reiterated this determination in a subsequent Resolution and Order issued on December 14, 2021, wherein it scheduled a virtual Technical Conference for February 8, 2022, to discuss the initial results of the Avoided Cost Study.[4]

B. Technical Conference #1

On February 8, 2022 the Energy Bureau held Technical Conference #1 ("Technical Conference #1") in which the Energy Bureau consultants provided a presentation on the initial results of the Avoided Cost Study (the "February 8 Presentation").[5] On March 7, 2022

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[1] *In re: Review of the Puerto Rico Electric Power Authority Integrated Resource Plan,* Case No. NEPR-AP-2023-0003.

[2] Resolution and Order, *In re: Puerto Rico Test for Demand Response and Energy Efficiency*, Case No. NEPR-MI-2021-0009 issued on May 14, 2021.

[3] *Id.*, August 13, 2021.

[4] *Id.*, December 14, 2021.

[5] *Id., Puerto Rico Avoided Cost Modeling Technical Conference*. February 8, 2022. Available at: https://energia.pr.gov/wp-content/uploads/sites/7/2022/02/20220207-NEPR-MI-2021-0009-PR-Avoided-Cost-Modeling-Presentation_02_08_22_FINAL.pdf ("February 8 Presentation")

LUMA[6] submitted a document titled *Motion Submitting LUMA's Comments on Attachments A and B of the Energy Bureau Resolution and Order of February 7, 2022, and on Avoided Cost Modeling Presentation,* in which LUMA filed its comments to the February 8 Presentation ("March 7 Motion").[7] On June 6, 2022 the Energy Bureau issued a Resolution and Order ("June 6 Resolution") providing its responses to the questions and comments submitted by LUMA in its March 7 Motion and scheduled a Technical Conference to discuss the Avoided Cost Study for June 22, 2022.[8]

C. Technical Conference #2

On June 22, 2022, the Energy Bureau held Technical Conference #2 ("Technical Conference #2") wherein the Energy Bureau consultants provided a presentation on the results of the Avoided Cost Study (the "June 22 Presentation") which included a discussion of LUMA's Questions and Comments provided in the March 7 Motion, the consultants' avoided capacity costs determination, and the avoided greenhouse gas emissions costs.[9]

In addition, as part of their June 22 Presentation, the Energy Bureau consultants set forth the following three discussion questions:

1. Lower peak load and lower energy needs leads to lower overall resource requirements and fuel consumption. Different capacity trajectory analyses could be considered, but all would give rise to roughly similar patterns as seen here. Is there value in continuing to "sensitivity test" capacity trajectories, given the purpose of this exercise?

2. Year-over-year values fluctuate significantly. Should we consider average values when computing actual benefits?

    a. Use "no energy efficiency" case marginal energy costs/prices for avoided energy metric, applied on an annual basis
    b. Use differential case assessment for the avoided capacity metric, but apply an average over the planning horizon

3. There is no explicit carbon price for greenhouse gas emissions cost savings in Puerto Rico. What is the best way to estimate the carbon savings benefit of energy efficiency implementation?

During the June 22 Presentation, LUMA asked questions and made comments regarding the avoided capacity costs determination. LUMA also requested that it be provided time

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[6] LUMA Energy, LLC, and LUMA Energy ServCo, LLC (jointly referred as, "LUMA").

[7] *In re: Puerto Rico Test for Demand Response and Energy Efficiency*, Case No. NEPR-MI-2021-0009 *Motion Submitting LUMA's Comments on Attachments A and B of Energy Bureau Resolution and Order of February 7, 2022, and on Avoided Cost Modeling Presentation Subject: Comments on Attachments A and B to Resolution and Order of February 7, 2022, and on Avoided Cost Modeling Presentation* filed by LUMA on March 7, 2022 ("March 7 Motion")

[8] Resolution and Order, *In re: Puerto Rico Test for Demand Response and Energy Efficiency*, Case No. NEPR-MI-2021-0009 issued on June 6, 2022.

[9] *In re: Puerto Rico Test for Demand Response and Energy Efficiency*, Case No. NEPR-MI-2021-0009 *Puerto Rico Avoided Cost Study: Avoided Capacity Cost,* June 22, 2022. Available at: https://energia.pr.gov/wp-content/uploads/sites/7/2022/06/Avoided-Cost-Technical-Conference-20220622-002.pdf ("June 22 Presentation")

following Technical Conference #2 to submit its written responses to the discussion questions presented by the Energy Bureau's consultants.

The Energy Bureau then issued a bench order directing LUMA to submit to the Energy Bureau, by June 29, 2022, the updated data on the pricing of the PV and BESS Projects approved in the Tranche 1 procurement process, and, by July 8, 2022, LUMA's input on the discussion questions put forth by its consultants during the Technical Conference (the "June 22 Bench Order"). In compliance with the June 22 Bench Order, on June 29, 2022, LUMA submitted, under seal of confidentiality, the updated pricing data of the PV and BESS Projects approved in the Tranche 1 procurement process to date.[10] On July 8, 2022, LUMA submitted comments in response to the three discussion questions included in the June 22 Presentation and high-level comments on subjects LUMA raised during Technical Conference #2.[11]

III. Next Steps

This Avoided Cost Study demonstrates the Energy Bureau's method for developing and structuring avoided costs and provides values for LUMA to use in developing its first three-year energy efficiency plan. The Energy Bureau **ADOPTS** the avoided cost values in the Avoided Cost Study for use by LUMA and others interested in cost-effectiveness screening of LUMA energy efficiency programs, until the Energy Bureau updates these values to reflect an updated IRP. LUMA is set to file a new IRP soon. Once the Energy Bureau has approved the 2024 IRP, the avoided energy, capacity, and greenhouse gas emissions costs will be updated to correspond to the approved IRP and the Energy Bureau will release an updated version of the Avoided Cost Study with those values.

Quantification of additional benefits will occur in later phases of work. The modeling for this Avoided Cost Study provides insight and data that can inform several more benefits, including the avoided Renewable Portfolio Standard compliance cost, avoided transmission capacity and system losses, and avoided distribution capacity and system losses. The Energy Bureau expects LUMA to review, comment on, and integrate additional avoided cost values into energy efficiency planning as they are available.

IV. Orders

The Energy Bureau **ORDERS** LUMA to apply the avoided energy, capacity, and greenhouse gas emissions values in this Avoided Cost Study in developing its first three-year energy efficiency plan and projecting the benefits of that plan.

Be it notified and published.

NEGOCIADO DE ENERGÍA DE PUERTO RICO
NEPR
JUNTA REGLAMENTADORA DE SERVICIO PÚBLICO

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[10] *In re: Puerto Rico Test for Demand Response and Energy Efficiency*, Case No. NEPR-MI-2021-0009 *Motion to Submit Solar Energy Generation and Storage Price Data in Compliance with Energy Bureau's Bench Order Issued During Technical Conference on June 22, 2022* filed by LUMA on June 29, 2022.

[11] *Id., Motion to Submit Comments in Response to Discussion Questions Presented During the Technical Conference of June 22, 2022, and in Compliance with Energy Bureau's Bench Order of that Date* file by LUMA on July 8, 2022.

Edison Avilés Deliz
Chairman

Lillian Mateo Santos
Associate Commissioner

Ferdinand A. Ramos Soegaard
Associate Commissioner

Sylvia B. Ugarte Araujo
Associate Commissioner

Antonio Torres Miranda
Associate Commissioner

CERTIFICATION

I certify that the majority of the members of the Puerto Rico Energy Bureau agreed on July 17, 2024. Also certify that on July 17, 2024, I have proceeded with the filing of this Resolution and Order and was notified by email to lionel.santa@prepa.pr.gov; laura.rozas@us.dlapiper.com; margarita.mercado@us.dlapiper.com.

I sign this in San Juan, Puerto Rico, today, July 17, 2024.

Sonia Seda Gaztambide
Clerk

NEGOCIADO DE ENERGÍA DE PUERTO RICO
NEPR
JUNTA REGLAMENTADORA DE SERVICIO PÚBLICO

Avoided Costs of Energy Efficiency Resources in Puerto Rico, 2023-2045

Avoided Energy Generation, Capacity, and Greenhouse Gas Emissions Costs for Use in Puerto Rico Cost Test and Related Benefit-Cost Analyses of Prospective Energy Efficiency Resources

Prepared for Puerto Rico Energy Bureau

June 5, 2024

AUTHORS
Jenn Kallay
Jon Tabernero
Asa Hopkins, PhD
Bob Fagan
Kyle Schultz
Divita Bhandari
Shannon Liburd

Synapse Energy Economics, Inc.

485 Massachusetts Avenue, Suite 3
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

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EXECUTIVE SUMMARY

Puerto Rico's legislative mandates require a reduction in electricity consumption by increasing investments in and energy savings from the installation of energy efficient equipment.[1] To set interim annual energy efficiency (EE) savings targets and approve programs and budgets, the Puerto Rico Energy Bureau (PREB) requires information on the cost-effective potential of EE programs. Determining the cost-effectiveness of EE programs requires quantitative values for costs and benefits and application of these values.

Energy efficiency cost inputs are more readily available than benefits inputs. The purpose of this Avoided Cost Study is to calculate the most impactful avoided costs (or benefits) and guide application of these monetized benefits to cost-effectiveness. The benefits addressed in this study include: (1) avoided energy generation costs, (2) avoided capacity costs, and (3) avoided greenhouse gas (GHG) emissions costs. Avoided environmental compliance costs and some of the avoided ancillary services are a component of the avoided energy generation costs and are thereby also included in this study.

To make these calculations, Synapse Energy Economics (Synapse) leveraged the avoided cost approach used in the Avoided Energy Supply Cost Study for New England states.[2] Synapse used the EnCompass power planning software to model the planning and operation of the Puerto Rico grid. We developed total cost and load projections for two hypothetical futures in which the utility or third-party program administrator does not install any new EE measures in 2023 or later years (referred to as the No EE scenario) and with EE (referred to as the Full EE scenario). Each scenario uses a capacity expansion profile to generate a set of resources to meet load, and then simulates hourly dispatch across all years of the planning horizon, 2021-2038. These scenarios are grounded in Puerto Rico's Modified Approved Integrated Resource Plan.[3]

We calculate the avoided energy generation costs by aggregating load-weighted real marginal energy prices for every hour of every year by three recommended time periods. Based on the underlying data, we recommend: Daytime: 7am-4pm (hours 7-16), Evening (peak): 4pm-11pm (hours 16-23), and Overnight: 11pm-7am (hours 23-7). We calculate the avoided capacity costs using the difference between the fixed costs (adjusted for depreciation) in the No and Full EE scenarios divided by the delta in peak load. We calculate the avoided greenhouse gas emissions costs using the difference in emissions

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[1] Act 17-2019 requires a 30 percent increase in energy efficiency by 2040.

[2] Synapse Energy Economics, Resource Insight, Les Deman Consulting, North Side Energy, and Sustainable Energy Advantage. *Avoided Energy Supply Components in New England: 2021 Report.* Prepared for AESC 2021 Study Group. Released March 15, 2021. Amended May 14, 2021. Available at: https://www.synapse-energy.com/avoided-energy-supply-costs-new-england-aesc

[3] Puerto Rico Energy Board. Case No.: CEPR-AP-2018-0001. *Final Resolution and Order on the Puerto Rico Electric Power Authority's Integrated Resource Plan.* August 24, 2020. Available at: https://energia.pr.gov/wp-content/uploads/sites/7/2020/08/AP20180001-IRP-Final-Resolution-and-Order.pdf

in metric tons in the No and Full EE scenarios divided by the difference in energy generation in MWh. We multiply this value by the approved federal social cost of carbon with a 3 percent discount rate from February 2021 in dollars per metric ton.[4] We extend all avoided cost values through 2045 by holding the 2038 value constant through the end of the study period.[5]

Table ES-1 below summarizes the avoided costs, including breakouts for avoided energy generation and GHG emissions costs by three periods. All values in this report are in 2023 dollars unless otherwise stated. We provide an electronic version of this table in Excel as Appendix A.

[4] Whitehouse.gov. Technical Support Document: Social Cost of Carbon and Nitrous Oxide Interim Estimates under Executive Order 13990. Interagency Working Group on Social Cost of Greenhouse. February 2021. Available at: https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

[5] All values can be extended beyond 2045 to accommodate measures with longer measure lives by holding the 2045 values constant in real terms.

Table ES-1. Avoided Energy Generation, Capacity, and Greenhouse Gas Emissions Costs, 2023–2045

Year	Avoided Energy Generation Costs ($/MWh)			Avoided Capacity Cost ($/kW-year)	Avoided GHG Emissions Costs ($/MWh)		
	Daytime	Evening (Peak)	Overnight		Daytime	Evening (Peak)	Overnight
2023	$98	$141	$108	$0	$0	$0	$0
2024	$79	$122	$99	$0	$0	$0	$0
2025	$70	$109	$94	$50	$12	$41	$31
2026	$67	$100	$91	$74	$6	$20	$10
2027	$72	$91	$91	$91	$17	$19	$21
2028	$84	$95	$96	$62	$36	$8	$9
2029	$85	$95	$96	$(19)	$24	$10	$5
2030	$80	$89	$91	$(8)	$12	$7	$(2)
2031	$77	$86	$86	$2	$10	$13	$8
2032	$69	$77	$78	$82	$12	$14	$17
2033	$47	$85	$88	$116	$3	$7	$2
2034	$43	$82	$86	$104	$4	$9	$5
2035	$40	$78	$81	$95	$4	$9	$8
2036	$40	$81	$85	$88	$3	$9	$10
2037	$36	$76	$80	$82	$3	$9	$11
2038	$34	$76	$81	$76	$3	$9	$11
2039	$34	$76	$81	$76	$3	$9	$11
2040	$34	$76	$81	$76	$3	$9	$12
2041	$34	$76	$81	$76	$3	$9	$12
2042	$34	$76	$81	$76	$3	$9	$13
2043	$34	$76	$81	$76	$3	$10	$13
2044	$34	$76	$81	$76	$3	$10	$14
2045	$34	$76	$81	$76	$3	$10	$14

The avoided energy generation and greenhouse gas emissions costs comprise the bulk of the value of EE resources for Puerto Rico in the nearer term. Avoided energy generation and greenhouse gas emissions costs in the early years are based on direct savings from using less residual fuel oil (RFO) and natural gas as marginal generating resources. The avoided costs decline over time as the resources on the margin (i.e., those that determine hourly prices) gradually include greater amounts of battery energy storage. Unlike fossil peaking capacity, battery capacity has an everyday role in the energy system regardless of the level of peak load. These avoided costs are impacted by the presence of battery energy storage in increasingly large amounts over the study period, allowing shifting of ever-increasing solar production and operation of battery storage resources as the marginal resource. Battery energy storage costs are lower cost due to the lower energy charging costs from the use of increased solar PV on the system. These avoided costs continue to include savings from less fuel oil and natural gas use in the later years, as these fuels continue as marginal until they are no longer utilized in Puerto Rico. However, the source of the savings shifts to include a reduction in the level of solar PV needed as overall load is reduced.

Avoided energy generation and greenhouse gas emission costs are highest in the evening hours through the first four years of the study period, when they meet the values in the overnight hours and remain relatively steady through the end of the study period. The notable exception is the daytime avoided energy generation cost, which declines and diverges as it does so; this reflects the increasing penetration of solar PV throughout the study period.

The avoided capacity value peaks in 2027, falls through 2029, and rises again through 2033, before leveling out in the later years of the planning horizon. The avoided capacity costs from lower peak loads are based on reduced capacity needed to meet peak hour loads, which does not take place until much later in the planning period. This is because the resources include a substantial amount of new solar PV and battery storage, at similar paces and levels across the No EE and Full EE scenarios. In the outer years of the planning horizon, there is lower overall solar PV and overall battery resources in the Full EE scenario as compared to the No EE scenario. The negative values in some years are an artifact of the modeling algorithm that builds new capacity in different sequences in the two scenarios and the calculations of the benefit of EE measures that impact peak load will generally average out the fluctuations resulting from this modeling result.

As a next step, LUMA is set to file a new integrated resource plan in 2024. Once the Energy Bureau has considered the new IRP and finalized a new, approved plan, the methods used to develop the avoided costs in this report can be updated to correspond to the new plan and used for efficiency program planning and cost-effectiveness screening. The modeling for this Avoided Cost Study provides insight and data that we will use to inform quantification of several more benefits in the next phase of this work, including the avoided Renewable Portfolio Standard compliance cost, avoided transmission capacity and system losses, and avoided distribution capacity and system losses.

1. INTRODUCTION

Puerto Rico's legislative mandates[6] require a reduction in electricity consumption by increasing the energy efficiency (EE) of equipment using electricity (such as lights, refrigerators, air conditioners, water heaters, and electronic devices). These mandates require sustained and systematic programmatic support by Puerto Rico Electric Power Authority (PREPA), LUMA, third-party program administrators, and installation contractors in Puerto Rico to replace outdated and/or inefficient equipment. Utility-sponsored programs that improve awareness of energy efficiency, increase access to efficient equipment, and lower upfront costs of this equipment help to remove barriers to uptake.

To set interim annual EE savings targets, the Puerto Rico Energy Bureau (PREB) requires information on the cost-effective potential of EE programs to meet both electric grid and customer needs. Determining the cost-effectiveness of these EE programs requires a two-step process:

1. A cost-effectiveness screening test (the "Puerto Rico Test") to define what costs and benefits to include in the evaluation of EE cost-effectiveness. This step was addressed by a previous effort and a summary is provided as Table 1 below.[7]

2. Quantitative values to populate the Puerto Rico Test and application of these values. This report provides some of the quantitative values for application in this step.

All the impacts included in this study are highlighted in blue in Table 1.[8] We also shaded several rows in the table in lighter grey which are not PREB's responsibility to develop as the value is either LUMA's responsibility to provide or the value is not available in the near-term as it is more difficult to determine.

[6] Act 17-2019 requires a 30 percent increase in energy efficiency by 2040.

[7] Puerto Rico Test for Demand Response and Energy Efficiency. Case No. NEPR-MI-2021-0009. Notice of Proposed Regulation and Request for Public Comment. February 7, 2022. Available at: https://energia.pr.gov/wp-content/uploads/sites/7/2022/02/20220207-MI20210009-Resolution-and-Order-NPR-RPC-1.pdf

[8] The components and descriptions below are from pages 7–16 and 19–20 of the Puerto Rico Benefit-Cost Test Technical Workshop Summary Report from December 15, 2021.

Table 1. Proposed Puerto Rico Test Framework with Avoided Cost Study Phase I Benefits Highlighted

Category	Impact	Include in First Application	Monetize in First Application	Method for First Application
Utility System Impacts				
Generation	Energy Generation	Yes	Yes	Avoided Cost Study
	Capacity	Yes	Yes	Avoided Cost Study
	Environmental Compliance	Yes	Yes	Avoided Cost Study
	Renewable Portfolio Standard Compliance	Yes	Yes	Jurisdiction-specific value needed
	Ancillary Services	Yes	Yes	Jurisdiction-specific value needed
Transmission	Transmission Capacity	Yes	Yes	Jurisdiction-specific value needed
	Transmission System Losses	Yes	Yes	Jurisdiction-specific value needed
Distribution	Distribution Capacity	Yes	Yes	Jurisdiction-specific value needed
	Distribution System Losses	Yes	Yes	Jurisdiction-specific value needed
General	Utility Program Incentives	Yes	Yes	LUMA Plan Filing
	Program Administration Costs	Yes	Yes	LUMA Plan Filing
	Program Administrator Performance Incentives	Yes if applicable	Yes	LUMA Plan Filing
	Credit and Collection Costs	No	Yes	Supplied by LUMA pending data availability
	Utility Rate Riders	No	Yes	Supplied by LUMA pending data availability
	Risk	Yes	No	Qualitative
	Reliability	Yes	No	Qualitative
	Resilience	Yes	No	Qualitative

Category	Impact	Include in First Application	Monetize in First Application	Method for First Application
Host Customer Impacts				
Host Customer Energy Impacts	Host Customer Portion of DER Costs	Yes	Yes	Market data or proxy
	Interconnection Fees	No	Yes	N/A
	Risk	No	No	N/A
	Reliability	No	No	N/A
	Resilience	No	No	N/A
	Tax Incentives	No	No	N/A
Host Customer Non-Energy Impacts	Other Fuels and Water	Yes	Yes	Jurisdiction-specific value needed
	Property Asset Value	Yes	No	Adder
	Health & Safety	Yes	No	Adder
	Empowerment, Satisfaction & Pride	Yes	No	Adder
	Comfort	Yes	No	Adder
	Productivity	Yes	No	Adder
	Low-Income Host Customer NEIs	Yes	No	Adder
Societal Impacts				
Societal Impacts	GHG Emissions	Yes	Yes	SCC
	Other Environmental	Yes	No	Qualitative
	Economic and Jobs	Yes	No	Qualitative
	Energy Security	Yes	No	Qualitative

Energy efficiency cost inputs are more readily available than benefits inputs. As a result, the purpose of this Avoided Cost Study is to calculate the avoided costs for the most impactful benefits and inform application of these monetized benefits to cost-effectiveness evaluations of EE potential studies and implementation plans. The benefits addressed in this study include: (1) avoided energy generation costs, (2) avoided capacity costs, and (3) avoided GHG emissions costs. Installation of energy efficiency measures that reduce overall annual energy requirements for the Puerto Rico system and reduce the peak load result in reduced annual fuel consumption and lower overall capacity needs (and, over time, a reduced need for additional renewable energy).

- <u>Avoided energy generation costs:</u> The reduction in fuel and other varying operating costs is the avoided energy. The avoided energy generation costs include expenses from the production or procurement of energy (i.e., kWh) from generation resources on behalf of customers. These expenses should include the fuel cost and variable O&M costs and can vary by season and time of day. Avoided environmental compliance costs and some of the avoided ancillary services are a component of the avoided energy generation costs and are thereby also included.[9]

- Avoided capacity costs: The reduced capacity needed is the avoided capacity. The avoided capacity costs are based on whether the EE resource coincides with the system peak.

- Avoided greenhouse gas emission costs: Reducing the total energy required also avoids emission of greenhouse gases. These avoided emissions have a societal value that can be expressed in monetary terms.

Application of these values involves conducting a benefit-cost analysis (BCA). BCA is assessed by comparing the sum of the present value of all the benefits (in dollars) to the sum of the present value of all the costs. The results of BCA can be reported in the form of (1) present values of costs and benefits, (2) net benefits, which involves subtracting the present value costs from the present value benefits, and (3) a benefit-cost ratio (BCR), which involves dividing the present value benefits by the present value costs. A positive net benefit and a BCR of 1.0 or higher indicates that the benefits of the investment are equal to or greater than the costs.

The remainder of the report is organized as follows:

- Section 2 discusses the development process and timing for the analysis and outputs.
- Section 3 provides an overview of the methodology and results.
- Section 4 outlines next steps.
- Appendix A provides the summary results table in Excel, for direct application in modeling.
- Appendix B provides a detailed discussion of key inputs and assumptions.

2. DEVELOPMENT PROCESS AND TIMING

The Avoided Supply Cost Study originates from Case No. NEPR-MI-2021-0009 PR Test Proceeding through a process that began in July 2021 and concludes with the issuance of a final report. During this time, PREB held three technical conferences which offered stakeholders the opportunity to ask questions and provide comments on the process, methodology, and inputs. The first technical conference in November 2021 clarified the scope, process, and schedule for the study and requested

[9] The modeling assumes environmental compliance with the Clean Air Act, Mercury and Air Toxic Standards, and the Clean Water Act (among others listed in the IRP) and these costs are reflected in the avoided energy generation costs. Similar to avoided environmental compliance costs, avoided ancillary services costs are reflected in the avoided energy generation costs. We only quantify a portion of the avoided ancillary services costs associated with avoided operation and maintenance costs.

data and information. The second technical conference in February 2022 provided a review of the draft avoided energy generation cost results and requested feedback. The third technical conference in June 2022 provided updates to the avoided energy generation cost results. This last conference also included a review of the draft avoided capacity and greenhouse gas emissions cost results and solicited further feedback.

The process of developing avoided costs began with PREB issuing data requests to LUMA and PREPA on August 13, 2021. The purpose of these data requests was to ensure that the Avoided Cost Study included the best available data and information and applied an appropriate methodology. On August 17, 2021, LUMA requested PREB to stay the resolution and order of August 13 and schedule a technical conference to resolve issues and questions related to the development of avoided cost estimates for use in benefit-cost analysis of energy efficiency programs. This first technical conference occurred on November 18, 2021.

The November technical conference revealed that LUMA and PREPA had helpful data and information and PREB reissued its data requests to LUMA and PREPA shortly thereafter. LUMA provided initial responses on January 10, 2022. These responses were integrated into the draft avoided energy cost results that were reviewed at the technical conference on February 8, 2022.

As requested, LUMA submitted feedback on the data inputs and methodology on March 7, 2022. LUMA's feedback informed updates to the avoided energy generation cost modeling which were reviewed along with the draft avoided capacity and greenhouse gas emission costs at the final technical conference on June 21, 2022. As requested, LUMA submitted feedback on the data inputs and methodology on July 8, 2022. This feedback did not change the modeling approach but was incorporated into this report as requested by LUMA.

3. METHODOLOGY AND RESULTS

This section describes the methodology and calculations used to develop the avoided energy generation, capacity, and greenhouse gas emission costs and the results. To make these calculations, Synapse Energy Economics (Synapse) leveraged a similar avoided cost approach to that used in the avoided energy supply cost study for New England states.[10] We discuss the avoided energy generation and capacity costs first and the avoided greenhouse gas emission reduction costs second.

[10] Synapse Energy Economics, Resource Insight, Les Deman Consulting, North Side Energy, and Sustainable Energy Advantage. *Avoided Energy Supply Components in New England: 2021 Report.* Prepared for AESC 2021 Study Group. Released March 15, 2021. Amended May 14, 2021. Available at: https://www.synapse-energy.com/avoided-energy-supply-costs-new-england-aesc.

3.1. Avoided Energy Generation and Capacity Costs

Synapse used the EnCompass power planning software to model the planning and operation of the Puerto Rico grid. Developed by Anchor Power Solutions, EnCompass is an optimization model that covers all facets of power system planning, including:

- Short-term scheduling, including detailed unit commitment and economic dispatch, with modeling of load shaping and shifting capabilities;
- Mid-term energy budgeting analysis, including maintenance scheduling and risk analysis;
- Long-term integrated resource planning, including capital project optimization, economic generating unit retirements, and environmental compliance; and
- Market price forecasting for energy, ancillary services, capacity, and environmental programs.

Synapse modeled the avoided energy and capacity costs at a PREPA-wide level and assumed unlimited transmission across the different regions. Synapse used a timeframe through 2038 to roughly align with the integrated resource plan (IRP) timeframe. Synapse then extended this timeframe to 2045 to cover the useful lives of the measures to be implemented in the EE programs.[11] The key inputs to this model include: (1) system parameters, (2) annual energy and peak load, (3) fuel prices, (4) renewable portfolio standard (RPS), (5) energy resource mix, (6) unit retirements, and (7) resource costs. Fuel prices are one of the most important inputs into the modeling because the energy that is avoided due to EE is fossil-fuel-based.

Fuel prices are one of the most important inputs into the modeling because the energy that is avoided due to EE is fossil-fuel-based.

Synapse originally populated the model using a database of Puerto Rico generation and load created by Horizons Energy. This database builds from the key assumptions made within the 2018–2019 IRP. For the No EE scenario, Synapse used the IRP's Scenario 3 Strategy 2 (S3S2) No Energy Efficiency with New Eco PPOA to align with the most recent PREB IRP Order and used the IRP's S3S2 (Base) scenario (also with New Eco PPOA) for the Full EE case. For new candidate resources, Synapse updated the capital cost expenditures to be consistent with the 2022 National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB).[12]

[11] The avoided cost trends can be extended beyond 2045 by holding the 2045 value constant in real terms, to accommodate measures with longer measure lives.

[12] National Renewable Energy Laboratory (NREL). 2022 Annual Technology Baseline. Electricity Annual Technology Baseline (ATB) Data Download. Available at: https://atb.nrel.gov/electricity/2022/data

As recommended by PREPA and LUMA, Synapse updated the avoided supply cost modeling to reflect the best available data at the time it was conducted. Synapse received and incorporated updates from PREPA and LUMA including:

- Annual energy and peak load forecasts and load shapes: The load forecast is based on the 2021 PREPA Fiscal Plan and shows higher load across all years.
- Energy efficiency forecast: The modeling reflects an updated full program launch date of 2025 with ramp-up starting in 2023.
- Fuel prices: The modeling applies futures prices from the U.S. Energy Information Administration's (EIA) Annual Energy Outlook 2022,[13] and 2021 prices are scaled up from a more complete set of fuel data for 2021 (11 months instead of 5 months). Fuel prices are higher in the early years due to higher futures prices that reflect greater oil and gas price uncertainty.
- Retirement dates: 42 MW of diesel capacity is available in the early years instead of retired as ordered in the IRP, resulting in fractionally higher diesel generation in the earlier years.
- RPS targets: Synapse constrained the buildout of solar and batteries to better reflect the procurement delays and the general lumpiness involved with procuring solar and batteries.[14] As a result, the proportion of renewable generation over time follows a non-linear trajectory and falls short of meeting the 2025 RPS requirement under the No EE and Full EE scenarios.

In the modeling environment, EnCompass tracks the quantity and cost of capacity added to the model to serve the peak load. The capacity required also includes additional reserves to meet planning and operating requirements. The model estimates the annual costs associated with carrying the investment required for new capacity, based primarily on the capital cost of the new resource amortized over time. These annual capacity carrying costs are directly available in the model for both the scenarios tested, and for all years of the planning horizon. The model also tracks the fixed costs associated with the existing fossil-fuel fleet, in addition to the operating costs of those resources if or when they are used to generate energy in the model. When those resources are retired, their fixed costs (in addition to their operating or variable costs) fall to zero in the model's cost accounting.

The modeling uses common assumptions across the two scenarios for fuel costs, new resource costs, and operation and maintenance (O&M) costs. The modeling results produce component costs for each year for fuel, non-fuel variable O&M, fixed O&M, and capital expenditures. The energy generation portion includes the fuel and non-fuel variable O&M. The capacity portion includes fixed O&M and capital expenditures. Synapse assumed capital expenditures are amortized based on the cost of capital and the period over which the resource is used (generally 20, 25, or 30 years), and computed an annual

[13] U.S. Energy Information Administration (EIA). Annual Energy Outlook 2022. Available at: https://www.eia.gov/outlooks/archive/aeo22/.

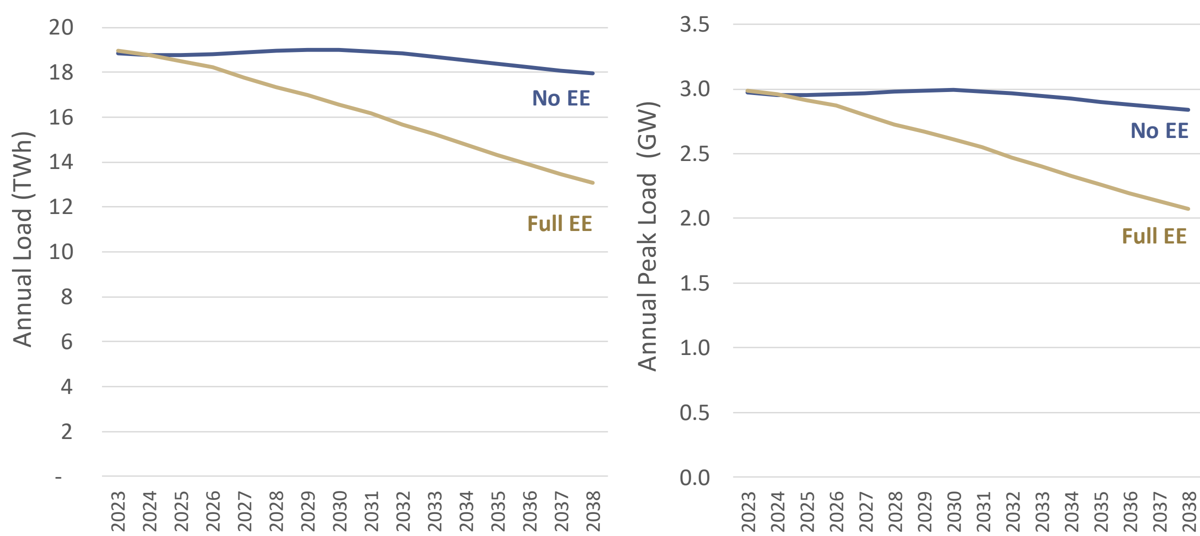
[14] Batteries included 4-hour and 6-hour resources. The modeling did not include 2-hour resources.

revenue requirement associated with that capital expense. Synapse also included marginal transmission and distribution technical losses in the forecast of avoided energy costs because efficiency reduces losses between generation and end use.

EnCompass dispatches the available resources to meet the actual hourly load (inclusive of system losses) in each hour. The model keeps track of the total production costs required to meet the load in each hour. The model continually tracks the extent to which zero-fuel-cost solar PV or wind resources are available and dispatched, and the need for fossil-based resources to meet the remaining need. The model also tracks the charging and discharging of battery energy resources, and the losses incurred in each charge-discharge cycle. These parameters – annual costs of new capacity, annual fixed costs for existing capacity, and annual production costs for energy dispatched – combined make up the total energy and capacity costs by year for each of the two scenarios modeled.

Figure 1 below shows the annual load and peak load projections for the No EE and Full EE scenarios. The No EE scenario assumes relatively flat trajectories. The Full EE scenario shows declining trajectories beginning in 2025, assuming EE program ramp-up during 2023–2024.

Figure 1. Annual Load and Peak Load Projections, No EE and Full EE Scenarios



Each scenario uses a capacity expansion profile to generate a set of resources to meet load, and then a simulated hourly dispatch across all years of the planning horizon, 2023–2038. Synapse used fixed or hard-coded input assumptions for oil, coal, and gas steam/combined-cycle resources, informed by the Modified Approved Integrated Resource Plan.[15] For example, the model assumed that oil steam retires by 2025, coal retires by the end of 2027, and EcoEléctrica (gas combined cycle) retires by the end of

[15] Puerto Rico Energy Board. Case No.: CEPR-AP-2018-0001. *Final Resolution and Order on the Puerto Rico Electric Power Authority's Integrated Resource Plan.* August 24, 2020. Available at: https://energia.pr.gov/wp-content/uploads/sites/7/2020/08/AP20180001-IRP-Final-Resolution-and-Order.pdf

2032, but the modeling could retire these resources earlier if they were not needed. We allowed more flexibility for other resources. For example, the model did not assume a fixed retirement date for Costa Sur 5 & 6 (gas steam) and San Juan 5 & 6 conversion (gas combined cycle). Appendix B provides a detailed unit-by-unit description of the approach to retirements.

Figure 2 below shows the No EE scenario retirements. Residual fuel oil (RFO) retires in 2024, diesel combustion turbines retire from 2024 to 2026, coal retires in 2027, Costa Sur 5 & 6 retire in 2028, and EcoEléctrica retires in 2032.

Figure 2. No EE Scenario Retirements

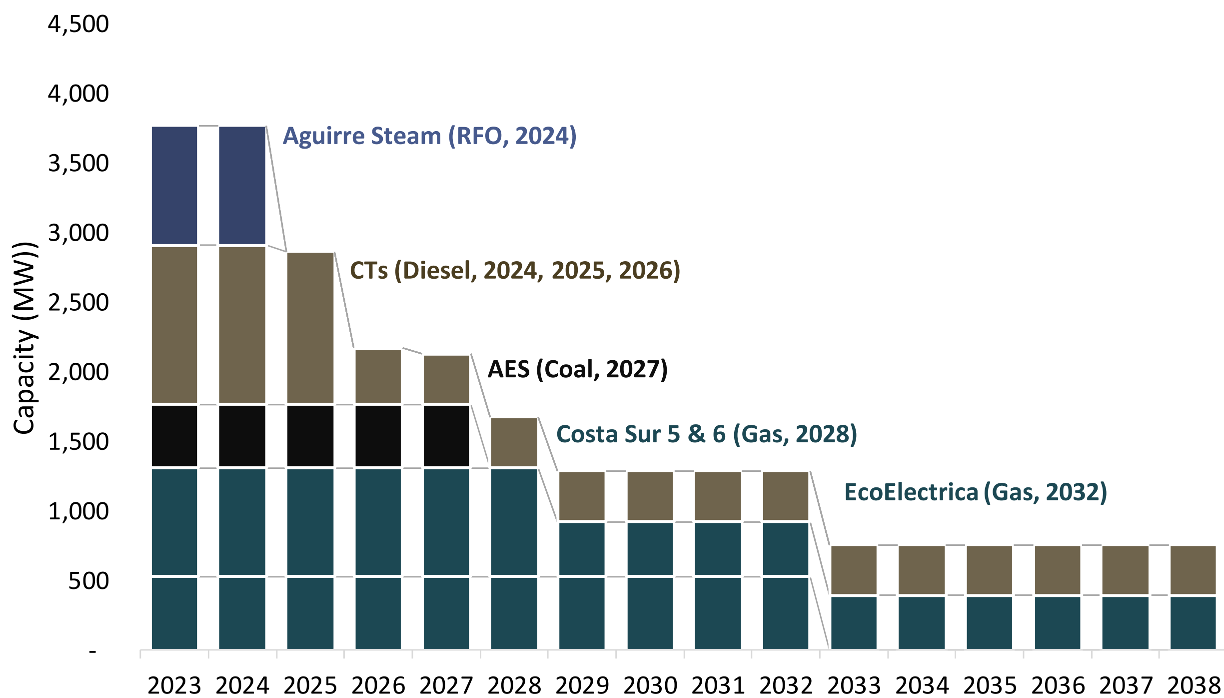
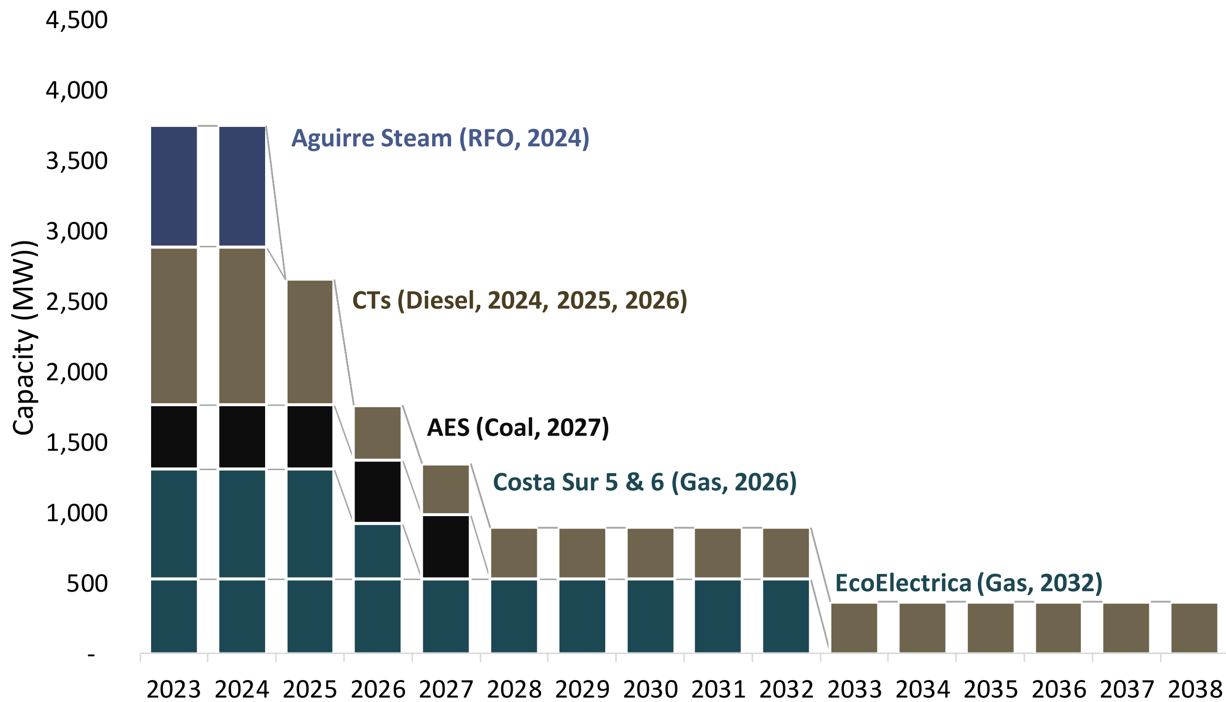


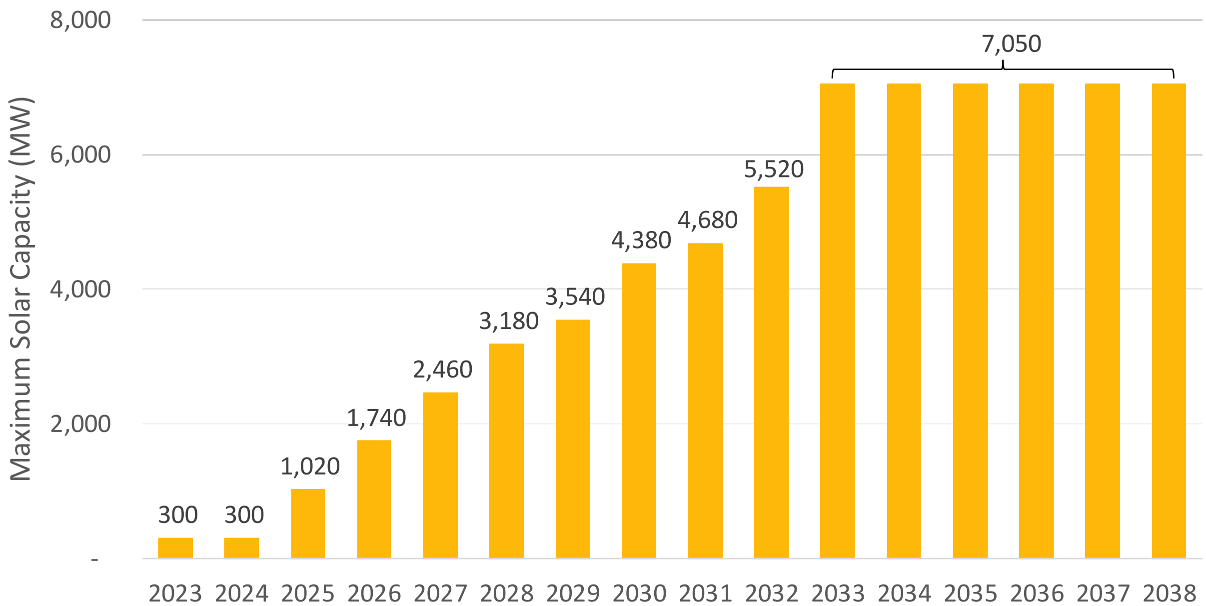
Figure 3 below shows the Full EE scenario retirements. In general, lower peak load in the Full EE scenario leads to earlier retirement for diesel combustion turbines and Costa Sur 5 & 6. The oil, coal, and EcoEléctrica retirements are the same as in the No EE scenario.

Figure 3. Full EE Scenario Retirements



Synapse used the optimization features of the EnCompass model to determine the ultimate buildout in the later years for new gas units (including combined-cycle, combustion-turbine, and reciprocating internal combustion engine units) and battery resources. New solar PV resources were capped in both scenarios, at levels for each year as shown in Figure 4 below. The No EE scenario built up to the maximum amount of solar each year, reflecting the increased need for additional generation given the absence of EE. The Full EE scenario built up to the maximum annual additions from 2023 to 2032 and slightly below the maximum from 2033 onwards.

Figure 4. Maximum Cumulative Solar PV Builds, No EE and Full EE Scenarios



Synapse then compared the model results to Puerto Rico’s RPS targets to see if the modeling results achieve the RPS targets. Puerto Rico’s RPS targets are 40 percent by 2025, 60 percent by 2040, and 100 percent by 2050.

Figure 5 below shows that the No EE scenario does not achieve the RPS targets from 2025 to 2027, when the renewable generation ranges from 23 to 37 percent. The No EE scenario then increases significantly to achieve a renewable fraction of 85 percent by 2038, well over the target.

Figure 5. Puerto Rico RPS Targets Compared to No EE Scenario RE Generation Results

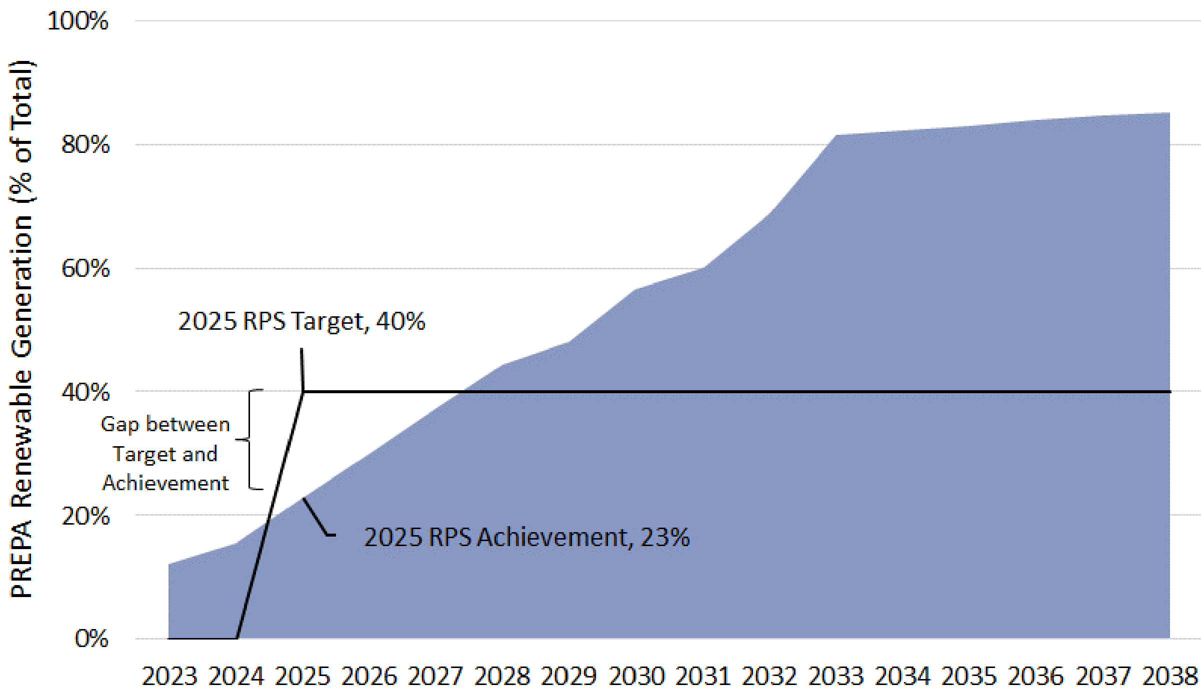


Figure 6 below shows that the Full EE scenario does not reach the RPS targets from 2025 to 2027, when the renewable generation ranges from 23 to 40 percent (similar to the No EE scenario). However, the Full EE scenario increases more than the No EE scenario, to reach a renewable energy fraction of 97 percent by 2038. Capacity additions in all scenarios are not dependent upon, or bound by, the RPS targets. Instead, renewable resources are built as quickly as practicable due to their favorable economics.

Figure 6. Puerto Rico RPS Targets Compared to Full EE Scenario RE Generation Results

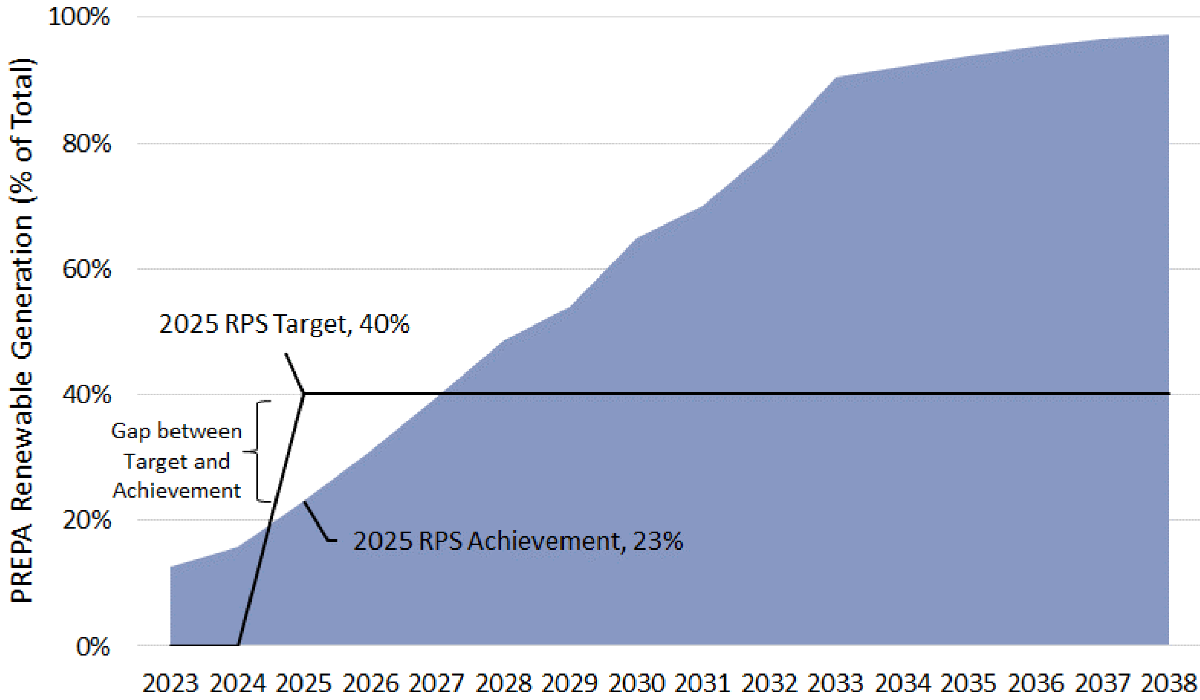


Figure 7 shows the capacity by year for the No EE scenario.

- RFO and diesel capacity decline significantly with larger unit retirements in 2024 and 2025, respectively.
- Coal capacity remains relatively steady through 2027, when it retires.
- Gas capacity increases due to the addition of a 302 MW gas combined-cycle unit in 2025. Gas capacity then remains relatively steady until 2028 and 2032 when Costa Sur 5 & 6 and EcoEléctrica retire, respectively.
- Solar capacity increases from 147 MW in 2023 to 7,266 MW in 2038.
- Battery capacity increases from 80 MW in 2024 to 4,600 MW in 2038.

Figure 7. Capacity by Year, No EE Scenario

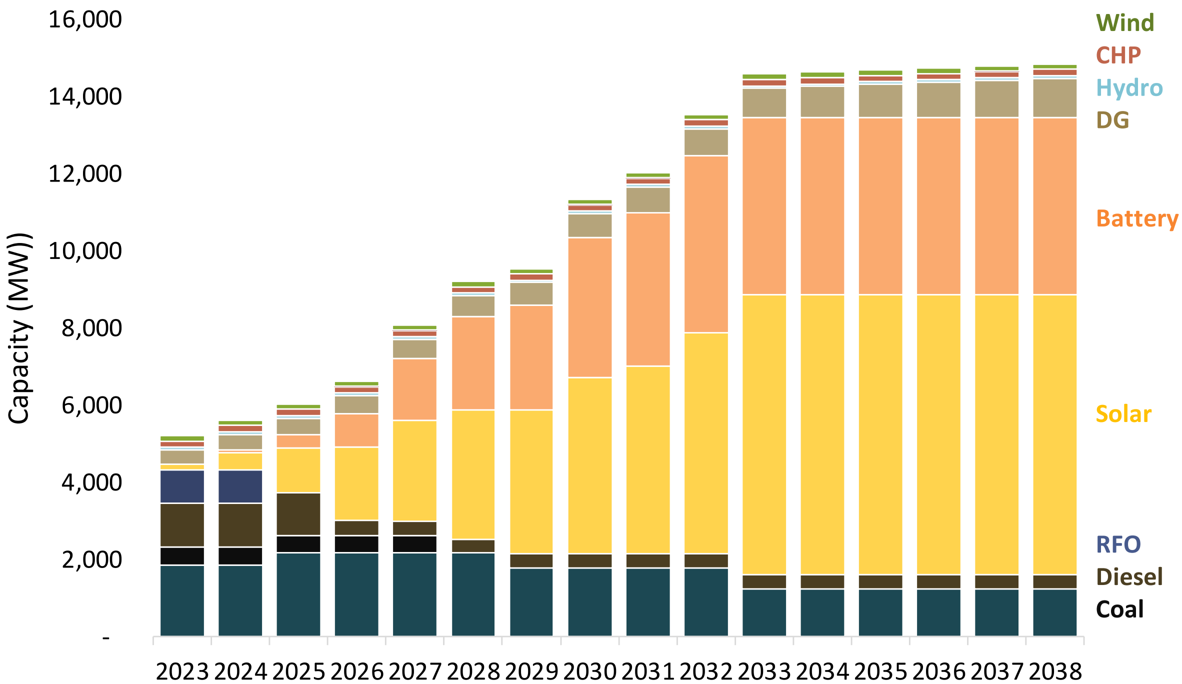


Figure 8 shows the capacity by year for the Full EE scenario. The Full EE scenario has a similar pattern as No EE scenario, but with lower levels of battery and solar PV as less new generation is needed to serve the lower load levels.

- RFO and coal capacity declines are the same as in the No EE scenario.
- Diesel capacity declines at a faster rate than in the No EE scenario.
- The gas capacity increase in 2025 is the same as in the No EE scenario, however it decreases after that year in the Full EE scenario. Costa Sur 5 & 6 retires earlier, and more gas capacity retires.
- Solar capacity increases from 147 MW in 2023 to 6,597 MW in 2038.
- Battery capacity increases from 280 MW in 2024 to 4,280 MW in 2038.

Figure 8. Capacity by Year, Full EE Scenario

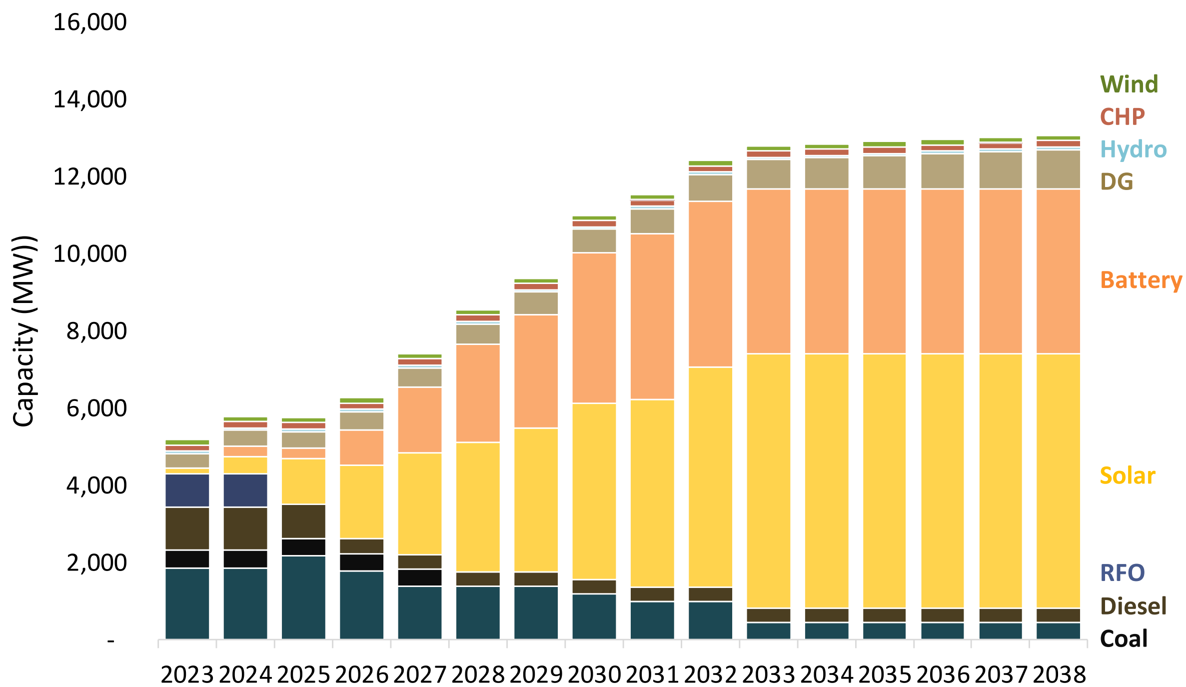


Table 2 summarizes the capacity in MW that is added (positive) or removed (negative) by resource in the No EE scenario as compared to the Full EE scenario. Without EE, 204 additional MW of gas and battery capacity is needed in 2025 and 923 additional MW of solar and battery capacity is needed in 2038.

Table 2. Capacity of No EE Scenario Minus Full EE Scenario, Total MW

Resource Type	2025	2038
Gas (Combustion Turbine)	144	-66
Battery	60	320
Solar	0	669
Total	**204**	**923**

Figure 9 shows the energy generation by year for the No EE scenario. Solar replaces much of the residual fuel oil (RFO), coal, and gas over time.

Figure 9. Energy Generation by Year, No EE Scenario

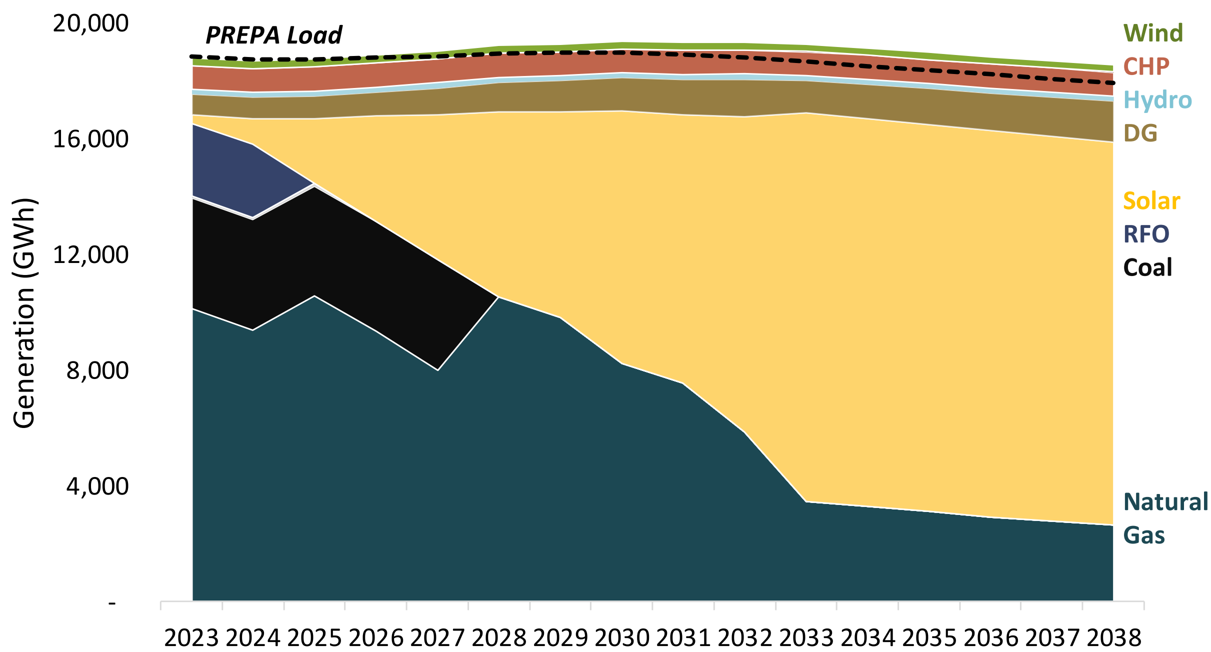


Figure 10 shows the energy generation by year for the Full EE Scenario. Full EE has a similar pattern to No EE (with solar replacing much of the fossil fuel generation), but with lower levels of solar given lower overall load levels. Also, gas use is nearly eliminated.

Figure 10. Energy Generation by Year, Full EE Scenario

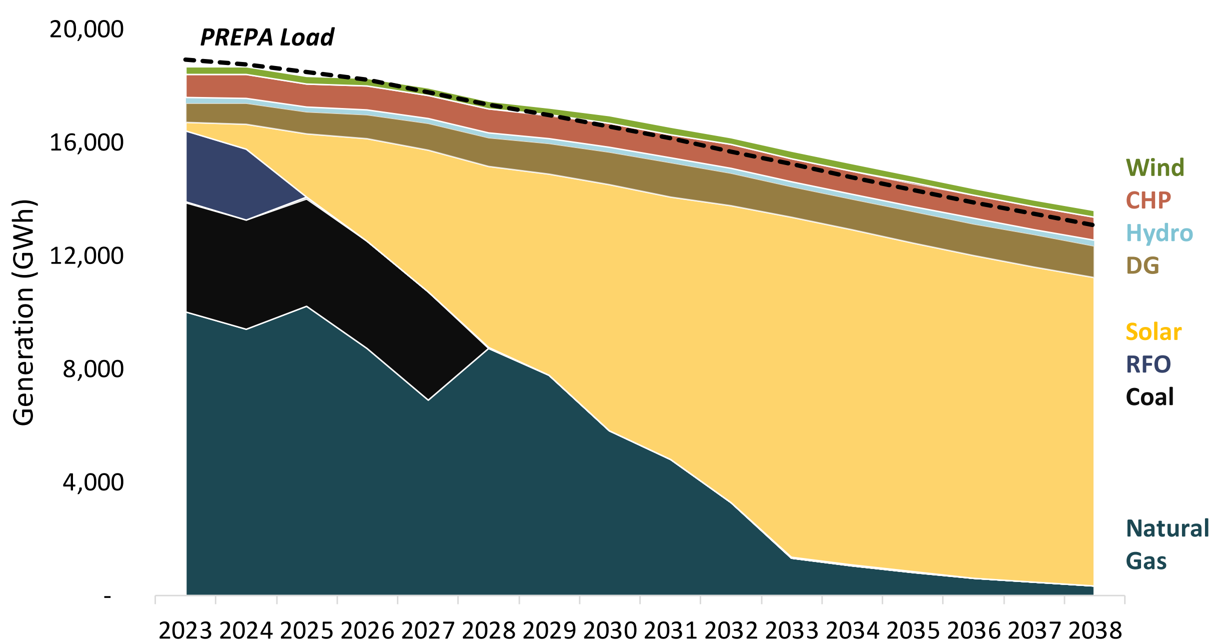


Table 3 provides the energy generation in GWh that is added (positive) or removed (negative) by resource in the No EE scenario, as compared to the Full EE scenario. Without EE, 516 additional GWh of mostly gas and battery generation is needed in 2025 and 6,120 additional GWh of mostly solar, gas, and battery generation is needed in 2038.

Table 3. Energy Generation of No EE Scenario Minus Full EE Scenario, Total GWh

Resource Type	2025	2038
Gas	372	2,310
Solar	3	2,388
Battery	94	1,149
Distributed generation	18	261
Coal	19	0
Wind	1	14
Diesel	10	-2
Total	**516**	**6,120**

The marginal energy prices associated with the No EE scenario reflect a rough measure of average hourly avoided energy costs because the marginal energy price is what would be required to meet the next increment of load. Electricity production costs vary across the hours of the day, as the load varies and the set of generating resources required to meet the load changes. Generally, the system dispatches less expensive resources first and the most expensive electricity generation is only utilized during the highest load hours of the day. The highest-cost resource needed to meet load at any given hour is referred to as on the margin and its cost defines which generating resources may be operating in that hour. Lower load due to the presence of EE resources leads to avoiding the higher costs of resources that would otherwise be on the margin; those avoided costs may vary in every hour.

By 2030, batteries are the marginal resource in more than 80 percent of the hours, as shown in Figure 11 below. Puerto Rico has many drivers for installing battery energy storage as a capacity resource including the need to retire older power plants and the need to shift solar PV production from midday periods to evening peak periods. On the margin, lower peak load and reduced total energy from EE effects causes an incremental reduction in later year battery requirements to serve nightly peaks.

Figure 11. Resources on the Margin in the No EE Scenario

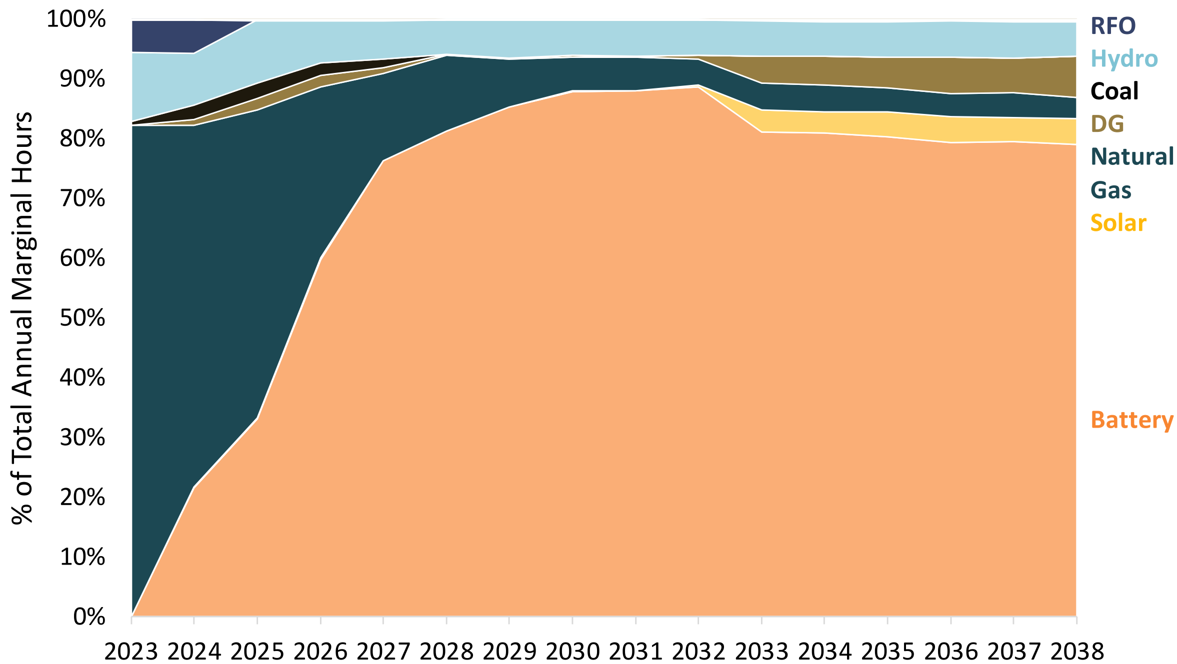
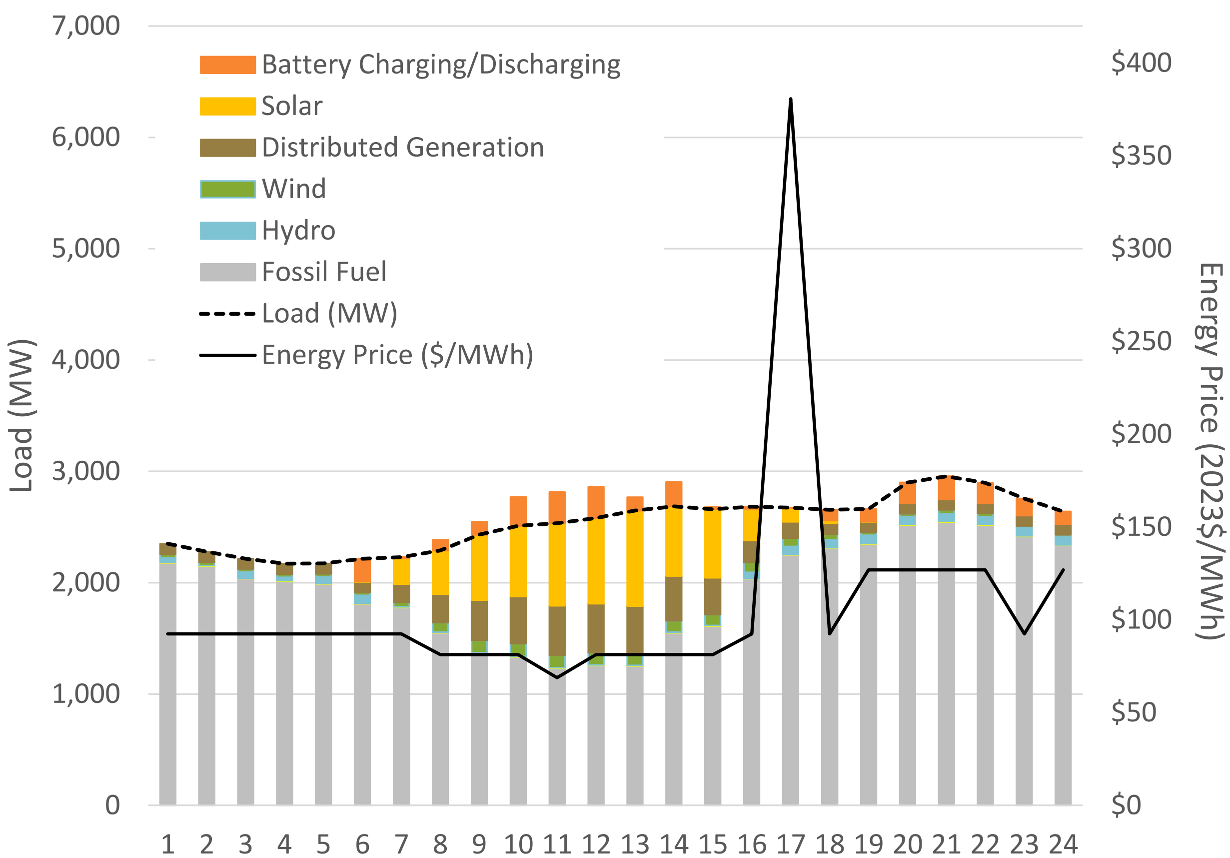


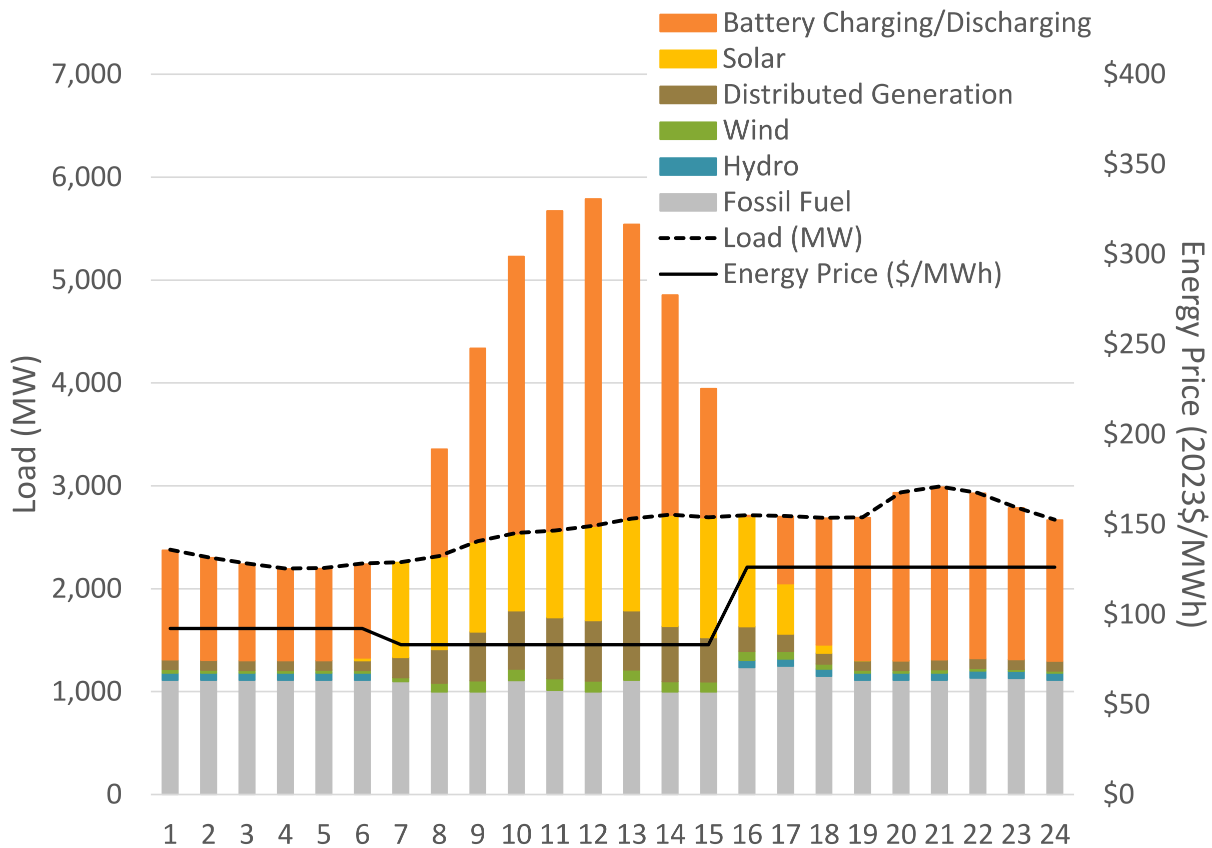
Figure 12, Figure 13, and Figure 14 below summarize the peak day load, resources, and energy prices (in 2023$/MWh) in the No EE Scenario for 2025, 2030, and 2038, respectively. These figures show how the resources affect energy pricing in each hour of the peak day. In 2025, energy prices spike to $380 per MWh at 5pm as the generation from solar resources tapers off. From that point through midnight each day, energy prices hover around $100 to $125 per MWh, a value largely determined by the fuel price and efficiency of the marginal fossil fuel generator.

Figure 12. 2025 Peak Day Load, Resources, and Energy Prices, No EE Scenario



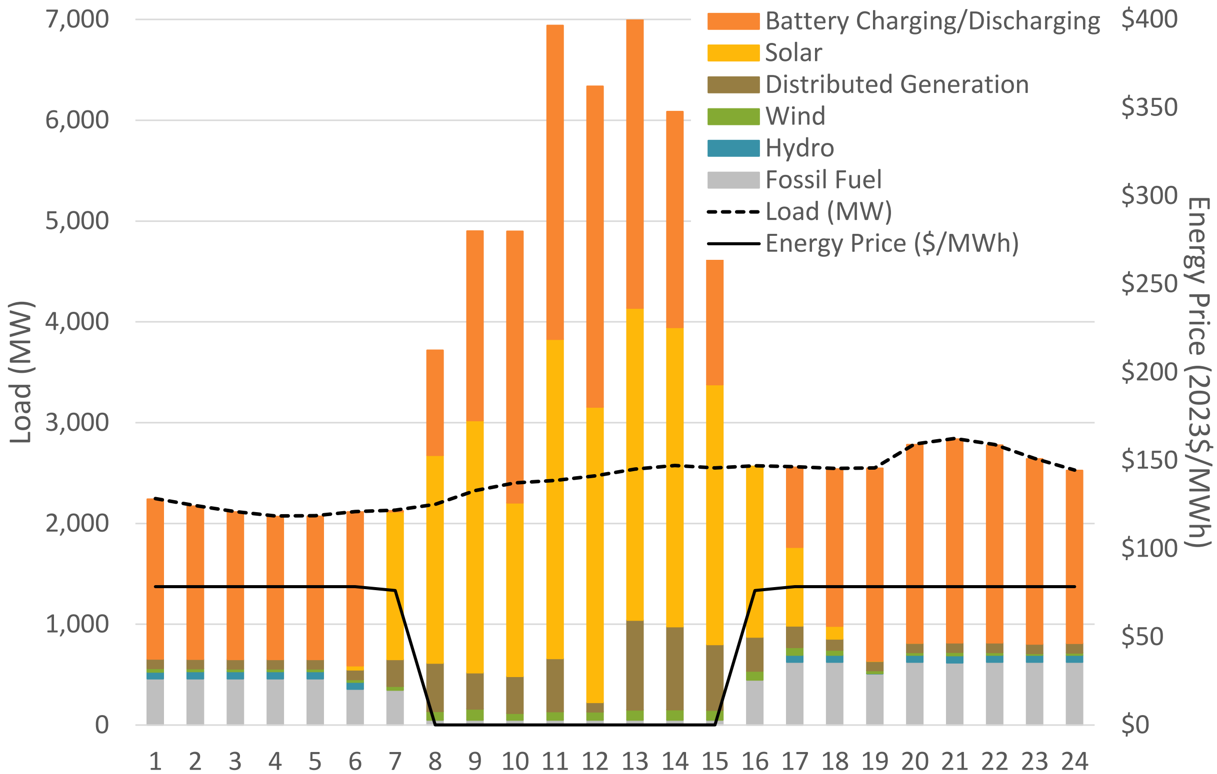
On the peak day in 2030, energy prices increase from $80 per MWh prior to 4pm to $125 per MWh at 4pm as the generation from solar resources tapers off. Prices continue at that level through midnight.

Figure 13. 2030 Peak Day Load, Resources, and Energy Prices, No EE Scenario



In 2038, energy prices on the peak day are $0 per MWh from 8am to 3pm as solar provides nearly all the energy required. Energy prices hover at $80 per MWh in all other hours of the day, largely reflecting the cost of solar PV generation recovered from battery storage.

Figure 14. 2038 Peak Day Load, Resources, and Energy Prices, No EE Scenario



Over any given period (such as on-peak hours) the total costs avoided are equal to the sum of the costs avoided in each hour. When expressing "avoided costs" for a given year, or month, or season, or even for part of a day, the costs avoided represent an average of those marginal costs that were avoided in each hour. To calculate the avoided energy generation costs aggregated across several time periods, we sum the marginal energy costs across hours and divide this by the sum of the load across those same hours.

We first calculated load-weighted real hourly marginal energy prices for each month (in 2023$/MWh) to visualize trends. Table 4, Table 5, and Table 6 below summarize the load-weighted price data for the No EE scenario in heatmaps for 2025, 2030, and 2038, respectively. In 2025, we see three pricing periods emerge over the course of the day which are relatively consistent across the months of the year and years of the study period.

- Prices are generally the lowest during the daytime hours (the greenish hours in the center, approximately 7am to 4pm).
- Prices are generally highest during evening hours (the reddish hours to the right, roughly 4pm to 11pm).

- Prices decrease from the evening peak in the overnight hours (the yellowish hours to the left, from 11pm to 7am).

Table 4. 2025 Load-Weighted Marginal Energy Price ($2023/MWh) by Month and Hour of Day, No EE Scenario

	Hour Ending																							
Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	96	94	84	83	83	84	84	81	65	65	55	40	55	64	66	80	107	91	88	118	98	97	88	89
February	86	84	84	83	83	83	84	76	58	52	33	18	28	51	60	80	85	90	98	91	90	109	99	98
March	88	86	84	83	83	85	83	72	53	40	24	28	46	51	64	82	91	91	111	134	114	101	91	90
April	99	85	84	85	83	84	82	68	57	47	32	32	45	58	70	87	100	91	112	105	104	111	111	110
May	91	89	87	87	87	87	84	77	74	70	62	62	72	74	82	101	112	93	94	123	159	114	102	94
June	90	90	90	90	90	89	81	78	76	75	71	71	77	77	80	122	103	110	92	108	107	101	95	113
July	92	91	90	90	90	89	81	77	74	72	65	66	73	75	79	108	91	101	123	108	112	102	104	92
August	104	92	93	91	92	92	84	79	76	74	64	62	72	77	78	100	115	96	132	127	128	107	111	106
September	123	92	92	92	92	92	88	80	79	79	71	71	72	79	82	112	144	106	151	126	140	148	126	107
October	94	94	93	93	93	93	91	83	81	80	70	69	72	80	82	89	105	115	119	128	124	109	105	113
November	98	96	94	91	91	94	92	87	84	84	82	74	72	78	85	87	109	111	107	119	109	139	119	119
December	94	90	89	87	88	90	90	86	82	81	81	79	78	80	82	84	95	116	106	128	107	105	96	95

By 2030, the prices across the three daily periods are similar. The daytime pricing is higher than in 2025 and the evening is lower. The overnight period pricing is similar to 2025.

Table 5. 2030 Load-Weighted Marginal Energy Price ($2023/MWh) by Month and Hour of Day, No EE Scenario

	Hour Ending																							
Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	89	89	89	89	89	89	89	81	80	80	80	80	80	80	80	80	89	89	89	89	89	89	89	89
February	80	80	80	80	80	80	80	73	72	72	72	72	72	72	72	73	80	80	80	80	80	80	80	80
March	81	81	81	81	81	81	80	68	68	68	66	64	68	68	68	72	81	81	81	81	81	81	81	81
April	81	81	81	81	81	81	79	69	69	69	65	63	69	69	70	78	80	80	80	80	80	80	80	80
May	89	89	89	89	89	89	84	79	79	79	79	79	79	79	80	88	88	88	88	88	88	88	88	88
June	87	87	87	87	87	87	81	78	78	78	78	78	78	78	79	86	87	87	87	87	87	87	87	87
July	85	85	85	85	85	85	80	76	76	76	76	76	76	76	76	84	85	85	85	85	85	85	85	85
August	88	88	88	88	88	88	84	78	78	78	78	78	78	78	78	87	88	88	88	88	88	88	88	88
September	112	112	112	112	112	112	108	91	91	91	91	91	91	91	93	96	103	103	102	102	102	103	102	102
October	105	105	105	105	105	105	105	88	87	87	87	87	87	87	87	100	105	105	105	105	105	105	105	105
November	100	100	100	100	100	100	100	90	89	89	89	89	89	89	89	89	98	98	98	98	98	98	98	98
December	92	92	92	92	92	92	92	84	83	83	83	83	83	83	83	83	92	92	92	92	92	92	92	92

By 2038, the daytime period pricing dips substantially. Evening and overnight pricing decline as well, though less so, and remain similar to one another.

Table 6. 2038 Load-Weighted Marginal Energy Price ($2023/MWh) by Month and Hour of Day, No EE Scenario

	Hour Ending																							
Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	77	77	77	77	77	77	77	29	29	29	29	24	27	29	29	29	75	75	75	75	75	75	75	75
February	86	86	86	86	86	86	85	28	23	23	21	23	23	23	23	32	73	73	73	73	72	72	72	72
March	72	72	72	72	72	73	70	27	27	18	20	22	24	22	27	32	73	73	73	73	73	72	73	72
April	44	44	44	44	44	45	36	18	17	13	10	10	17	17	21	32	40	40	40	40	40	40	40	39
May	63	63	62	62	62	62	48	39	39	39	28	32	37	39	40	62	63	63	63	63	63	63	63	63
June	85	85	85	85	85	85	50	19	19	19	15	15	19	20	20	84	84	83	83	84	83	83	83	83
July	79	79	79	79	79	79	55	24	24	24	16	10	21	23	24	78	79	79	79	79	79	79	79	79
August	96	96	96	96	96	96	89	15	15	15	13	13	15	15	15	73	103	103	103	103	103	103	102	102
September	93	93	93	93	93	93	85	33	30	30	18	20	25	30	30	51	87	86	86	87	87	87	87	86
October	99	99	99	99	99	99	99	34	28	28	26	19	19	24	29	40	99	99	99	99	99	99	99	99
November	87	87	87	87	87	87	87	59	56	56	56	53	48	51	56	56	86	86	86	86	86	85	85	85
December	86	86	86	86	86	86	86	79	77	77	77	77	77	77	77	77	87	87	87	87	87	87	87	87

While we calculate load-weighted real marginal energy prices for each hour in each month of each year (in 2023$/MWh), it is time-consuming to apply the avoided costs in this way and can lead to a false sense of precision. We recommend aggregating the avoided costs into three time periods, as suggested by the data:

- Daytime: 7am-4pm (hours 7-16)
- Evening (peak): 4pm-11pm (hours 16-23)
- Overnight: 11pm-7am (hours 23-7)

We summarize the avoided energy generation costs by these periods in Table 7 below. To allow for application to longer-life measures in LUMA's upcoming three-year EE plan, we extended the values from 2038 through 2045 by holding the 2038 value constant. The values can be extended beyond 2045 to accommodate measures with longer measure lives by holding the 2045 value constant in real terms.

Table 7. Avoided Energy Generation Costs (2023$/MWh)

Years	Daytime	Evening (Peak)	Overnight
2023	$98	$141	$108
2024	$79	$122	$99
2025	$70	$109	$94
2026	$67	$100	$91
2027	$72	$91	$91
2028	$84	$95	$96
2029	$85	$95	$96
2030	$80	$89	$91
2031	$77	$86	$86
2032	$69	$77	$78
2033	$47	$85	$88
2034	$43	$82	$86
2035	$40	$78	$81
2036	$40	$81	$85
2037	$36	$76	$80
2038	$34	$76	$81
2039	$34	$76	$81
2040	$34	$76	$81
2041	$34	$76	$81
2042	$34	$76	$81
2043	$34	$76	$81
2044	$34	$76	$81
2045	$34	$76	$81

In summary, the avoided energy cost is higher for all periods in the earlier years as EE is directly displacing oil or gas consumption at power plants. The avoided energy cost declines over time as the resources on the margin (i.e., those that determine hourly prices) gradually include greater amounts of battery energy storage. In the later years of the study, EE is still displacing fossil fuel but at lower proportions of the total energy produced than in earlier years. Battery energy storage costs are lower cost due to the lower energy charging costs from the use of increased solar PV on the system. Over time, EE will compete with incremental renewable energy and battery storage resources to be the lowest cost resource as Puerto Rico moves away from a dependence on oil and gas to make electricity. The EE avoided costs reflect that benefit in the form of lower avoided costs.

Traditional EE and electrification measures can be thought of as passive resources that either decrease (EE) or increase (electrification) loads relative to a reference case. The timing of those reductions or increases in loads correspond to when the affected end-uses consume energy. For example, efficient lighting will yield a greater reduction in residential loads during the evening and efficient air conditioning will yield greater reductions during summer afternoons. Thus, there are important temporal aspects to these load changes, but they tend to be well correlated with weather, seasons, daylight, and building operation.

The benefit of this passive attribute is that the load impacts are more reliable, and their timing is more predictable. From a grid services perspective, a downside of this passive attribute is there is less flexibility to alter the load profiles to meet grid objectives. Many EE resources are not dispatchable, but a new class of resources is emerging that is more active and therefore more dispatchable. A few examples include smart thermostats, smart appliances, grid-integrated water heaters, and electric vehicles. These resources can be thought of as EE measures—or electrification for the case of electric vehicles—but their controllability features allow them to be used for other grid services, such as for addressing localized or system-wide capacity constraints. Therefore, they integrate features of EE and DR and are sometimes referred to as integrated DSM (iDSM) resources. Load impact profiles for iDSM will vary based on things like how much flexibility they offer, how they are controlled, and when they are needed by the grid, which means that developing load savings profiles requires consideration of different use cases. Some DR resources are also highly dispatchable. Further, some DR resources might be dispatched in response to customer interests while others might be dispatched to meet the short-term peak demands of the electricity grid. The dispatchability of an EE or DR resource should be accounted for in determining the peak availability of each resource. For measures that are actively controlled or dispatchable, the degree to which the measure can be dynamically controlled to align with the annual peak load, as well as loads within 5 percent of the peak, should be used as part of the characterization of the measure's ability to reduce or avoid peak load. Changes in load are characterized at the location of the end use resource, so their impact on the generation system must account for losses in the distribution and transmission system.

The primary form of capacity savings from EE is lower peak load and reduced total energy causing an incremental reduction in later year battery requirements to serve nightly peaks. While lower nightly peak load from EE reduces capacity need, incremental battery capacity is still required to store daytime solar energy, especially in later years with high solar PV levels. Unlike fossil peaking capacity, battery capacity has an everyday role in the energy system regardless of the level of peak load.

The methodology used to estimate the avoided capacity consists of taking the difference in the sum of total fixed costs (adjusting for depreciation) between the No EE and Full EE scenarios and dividing this difference by the delta in peak load between the No EE and Full EE scenarios. To allow for implementation in LUMA's upcoming three-year EE plan, we extended the values through 2045 by holding the 2038 value constant through the end of the study period. The values can be extended beyond 2045 to accommodate measures with longer measure lives by holding the 2045 value constant in real terms. Table 8 below shows the avoided capacity costs for each year, in $2023.

Table 8. Avoided Capacity Costs (2023$/kW-year)

Year	For Savings Coincident with Peak
2023	$0
2024	$0
2025	$50
2026	$74
2027	$91
2028	$62
2029	$(19)
2030	$(8)
2031	$2
2032	$82
2033	$116
2034	$104
2035	$95
2036	$88
2037	$82
2038	$76
2039	$76
2040	$76
2041	$76
2042	$76
2043	$76
2044	$76
2045	$76

The negative values in some years are an artifact of the modeling algorithm that builds new capacity in different sequences in the two scenarios. It reflects an optimization that accounts for the scenarios' needs to meet different patterns of energy and peak load reductions over time, while still incorporating the retirement requirements imposed on the model's optimization. The calculations of the benefit of EE measures that impact peak load will generally average out the fluctuations resulting from this modeling result.

There is not a significant difference in the capacity resources in place until much later in the planning period, when the overall energy and peak requirements begin to diverge materially. This is because the resources include a substantial amount of new solar PV and battery storage, at similar paces and levels across the No EE and Full EE scenarios. As a result, there is not a dramatic difference in the path of installation of solar PV and battery energy storage over the near-term period based on the planned EE programs. In the outer years of the planning horizon, the model optimization results in slightly lower overall solar PV and overall battery resources.

Noteworthy Points on the Methodology

This section notes several points regarding the approach and resulting outputs.

- This modeling is not intended to be a detailed operational representation. This modeling is a planning exercise designed to capture key changes to capacity and production trajectories under two different load trajectories.
- Actual prices/ratepayer costs in the No and Full EE scenarios will be different than the long-term prices calculated in this study since actual future costs will be subject to short-term variations in energy markets that are not known today.
- Because this study relies on a hypothetical No EE scenario that lacks some amount of anticipated demand-side measures, the No EE scenario should not be used to infer information about actual future market conditions, energy prices, or resource builds.
- Synapse acknowledges that these capital cost inputs do not reflect the nuances of local and operational constraints in Puerto-Rico's relatively small, island-based system which may drive higher costs. This implies that the value of EE as reflected in this report is likely lower than what will be seen. In other words, the avoided capacity costs – one of the benefits of peak-period load reducing EE – are higher if the actual capacity costs are more expensive than modeled.
- Potential supply chain delays and cost increases stemming from the post-COVID economic recovery are not captured in this modeling.
- Cost reductions due to recently enacted federal incentives for solar PV and storage are not captured in this analysis.
- Synapse used an 8 percent discount rate when estimating resource carrying costs. This may be low considering new resources will be installed by third parties who may require a higher return on capital.
- The No EE scenario does not include any explicit programmatic efforts but does include some amount of endogenous adoption of energy efficiency reflected in the macroeconomic trend.

3.2. Avoided Greenhouse Gas Emissions

The total carbon dioxide (CO_2) emissions for the No EE and Full EE scenarios are key outputs of the Encompass modeling. Synapse calculates the difference between the No EE and Full EE scenario total CO_2 emissions output to determine the avoided CO_2 emissions arising from the energy savings of the Full EE scenario for each period in metric tons. We hold the 2038 value constant through 2045.

We then divide the avoided emissions by the change in energy consumed in the two cases, to calculate the avoided emissions in metric tons per MWh change in load for each period. We multiply these values by the approved federal social cost of carbon with a 3 percent discount rate from February 2021 in 2023$ per metric ton.[16] This source provides values through 2045 so no extrapolation is needed.

Table 9 below shows the avoided costs that can be attributed to GHG emissions savings arising from reductions in energy consumption due to EE. The value of those emissions is small relative to the avoided energy costs and follows a similar trend as the avoided energy costs whereby the higher values correspond to evening and overnight periods when higher-emitting and higher-cost generation is in use. The avoided greenhouse gas cost drops over time across all periods (despite an increasing dollar value per metric ton) as the avoided emissions arise only from avoiding the energy related to the relatively small portion of fossil fuels still in the mix.

[16] Whitehouse.gov. Technical Support Document: Social Cost of Carbon and Nitrous Oxide Interim Estimates under Executive Order 13990. Interagency Working Group on Social Cost of Greenhouse. February 2021. Available at: https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

Table 9. Avoided GHG Emission Costs ($2023/MWh assuming a 3% discount rate)[17]

Year	Daytime	Evening (Peak)	Overnight
2023	$0	$0	$0
2024	$0	$0	$0
2025	$12	$41	$31
2026	$6	$20	$10
2027	$17	$19	$21
2028	$36	$8	$9
2029	$24	$10	$5
2030	$12	$7	$(2)
2031	$10	$13	$8
2032	$12	$14	$17
2033	$3	$7	$2
2034	$4	$9	$5
2035	$4	$9	$8
2036	$3	$9	$10
2037	$3	$9	$11
2038	$3	$9	$11
2039	$3	$9	$11
2040	$3	$9	$12
2041	$3	$9	$12
2042	$3	$9	$13
2043	$3	$10	$13
2044	$3	$10	$14
2045	$3	$10	$14

[17] Avoided GHG Emissions values on the period basis were estimated using a more updated version of the results that were run more recently with an updated version of EnCompass. Re-running the same scenario with this new EnCompass version results in slightly different results. Therefore, annual figures will be broadly similar but not exactly alike the periods analysis.

In summary, the avoided energy generation and greenhouse gas emissions costs comprise the bulk of the value of EE resources for Puerto Rico in the nearer term. Avoided energy generation and greenhouse gas emissions costs are highest in the evening hours through the first four years of the study period, when they meet the values in the overnight hours and remain relatively steady through the end of the study period. Avoided generation costs are lowest during the daytime hours throughout the study period. The avoided capacity value comes into play in the later years of the planning horizon.

4. NEXT STEPS

LUMA is set to file a new integrated resource plan in 2024. Once the Energy Bureau has considered the new IRP and finalized a new, approved plan, the methods used to develop the avoided costs in this report can be updated to correspond to the new plan. These values can then be used for efficiency program planning and cost-effectiveness screening.

Quantification of additional benefits will occur in subsequent phases of work. The modeling for this Avoided Cost Study provides insight and data that can be used to inform several more benefits, including the avoided Renewable Portfolio Standard compliance cost, avoided transmission capacity and system losses, and avoided distribution capacity and system losses. We highlight the benefits we will address in this next phase of work in orange in Table 10 below.

Table 10. Proposed PR Test Framework with Avoided Cost Study Phase I and Phase II Benefits Highlighted

Category	Impact	Include in First Application	Monetize in First Application	Method for First Application
Utility System Impacts				
Generation	Energy Generation	Yes	Yes	Avoided Cost Study
	Capacity	Yes	Yes	Avoided Cost Study
	Environmental Compliance	Yes	Yes	Avoided Cost Study
	Renewable Portfolio Standard Compliance	Yes	Yes	Jurisdiction-specific value needed
	Ancillary Services	Yes	Yes	Jurisdiction-specific value needed
Transmission	Transmission Capacity	Yes	Yes	Jurisdiction-specific value needed
	Transmission System Losses	Yes	Yes	Jurisdiction-specific value needed
Distribution	Distribution Capacity	Yes	Yes	Jurisdiction-specific value needed
	Distribution System Losses	Yes	Yes	Jurisdiction-specific value needed
General	Utility Program Incentives	Yes	Yes	LUMA Plan Filing
	Program Administration Costs	Yes	Yes	LUMA Plan Filing

	Program Administrator Performance Incentives	Yes - if applicable	Yes	LUMA Plan Filing
	Credit and Collection Costs	No	Yes	Supplied by LUMA pending data availability
	Utility Rate Riders	No	Yes	Supplied by LUMA pending data availability
	Risk	Yes	No	Qualitative
	Reliability	Yes	No	Qualitative
	Resilience	Yes	No	Qualitative

Category	Impact	Include in First Application	Monetize in First Application	Method for First Application
Host Customer Impacts				
Host Customer Energy Impacts	Host Customer Portion of DER Costs	Yes	Yes	Market data or proxy
	Interconnection Fees	No	Yes	N/A
	Risk	No	No	N/A
	Reliability	No	No	N/A
	Resilience	No	No	N/A
	Tax Incentives	No	No	N/A
Host Customer Non-Energy Impacts	Other Fuels and Water	Yes	Yes	Jurisdiction-specific value needed
	Property Asset Value	Yes	No	Adder
	Health & Safety	Yes	No	Adder
	Empowerment, Satisfaction & Pride	Yes	No	Adder
	Comfort	Yes	No	Adder
	Productivity	Yes	No	Adder
	Low-Income Host Customer NEIs	Yes	No	Adder
Societal Impacts				
Societal Impacts	GHG Emissions	Yes	Yes	SCC
	Other Environmental	Yes	No	Qualitative
	Economic and Jobs	Yes	No	Qualitative
	Energy Security	Yes	No	Qualitative

Appendix A. RESULTS TABLE

The attached table in Excel provides the results in a format that can be directly applied to and referenced in energy efficiency benefit-cost analysis modeling and calculations.

Appendix B. Detailed Inputs

This appendix details the inputs into the modeling including: (1) system parameters, (2) peak load and annual energy, (3) fuel prices, (4) renewable energy portfolio standard, (5) energy resource mix, (6) unit retirements, and (7) resource costs.

System Parameters

This study assumed the system parameters in Table 11 for the PREPA region for resource adequacy, reserves, and regulation. The operating reserves are based on the loss of the largest unit, EcoEléctrica. The regulation up/down parameters were based upon Horizons Energy conversation with PREPA operations staff in 2019.

Table 11. System Parameters

Parameter	Value
Reserve Margin	50% until end of 2024, 30% onwards
Operating Reserves	507 MW
Spinning Reserves	50% of Operating Reserves
Regulation Up/Down	60 MW until end of 2025, then 80 MW onwards

Peak Load and Annual Energy

Synapse initially relied on PREPA's 2018 IRP Long Term Capacity Expansion (LTCE) Result for the *S3S2 No EE with Eco New Contract* (New PPOA) for the system's total generation (GWh) and peak generation (MW)—adjusted for transmission and distribution losses from 2023–2038 for the island. Following comments submitted by LUMA regarding the Avoided Cost Technical Conference in February 2018, Synapse updated its load forecast to use the energy and peak load forecast in the 2021 FY Plan.

Table 12 shows the load parameters for the No EE scenario. This assumes average technical system losses of 4.8 percent and 2.8 percent of generation for the distribution and transmission systems, respectively.[18] For the hourly load shape, Synapse used the 2019 load shape data given by LUMA as part of Exhibit 1 of the discovery responses to Synapse, which contains the load shape data used in LUMA's 2021 MCOS Study prepared by Guidehouse.[19]

[18] PREPA 2018 IRP LTCE Result, S3S2 No EE with New Eco PPOA. Siemens. January 2020. Metrics tab.

[19] LUMA. 2022. PR Cost Test Response to Question 1-6. Case NEPR-MI-2021-009.

Table 12. No EE Scenario Load Parameters

Year	Annual Energy (GWh)	System Peak (MW)
2023	18,846	2,973
2024	18,750	2,955
2025	18,766	2,956
2026	18,818	2,962
2027	18,870	2,970
2028	18,963	2,982
2029	18,991	2,989
2030	19,005	2,993
2031	18,918	2,981
2032	18,830	2,969
2033	18,682	2,947
2034	18,534	2,925
2035	18,386	2,903
2036	18,237	2,881
2037	18,088	2,859
2038	17,944	2,842

Source: PREPA FY 2021 Fiscal Plan

EE Forecast

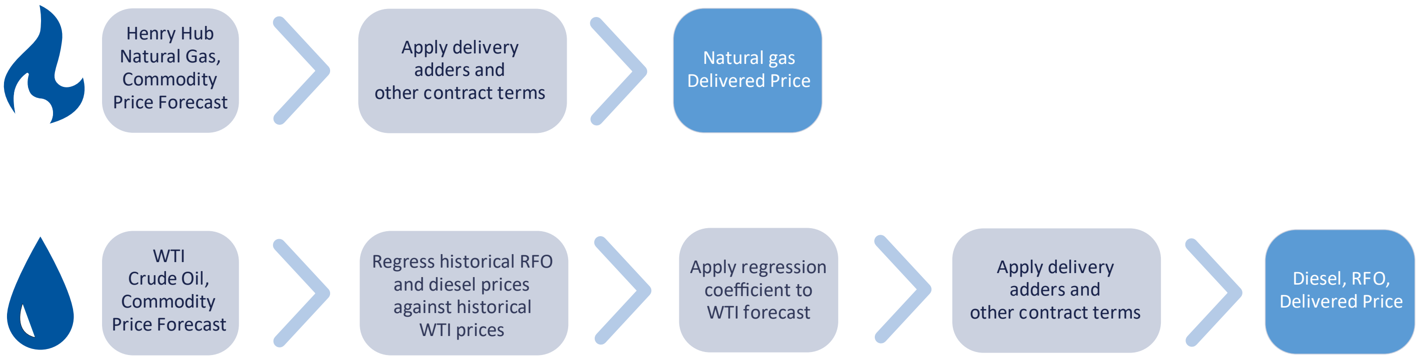
Synapse developed the difference in load between the No EE and Full EE cases by combining PREPA's updated no-EE load forecast from the 2021 Fiscal Plan (summarized in the previous section) with the EE forecast included in the approved IRP. Synapse then updated for the delay in EE program launch. Synapse started by increasing the 2021 load to the level in the Fiscal Plan, then keeping it level until 2023. We then applied EE savings of 0.1 percent in 2023 and 0.25 percent in 2024, reflecting the Transition Period Plan guidance in the Energy Bureau's Regulation for Energy Efficiency. From that point forward, we assumed annual EE savings ramp up at an increasing pace before stabilizing at a fixed level in 2026 and all subsequent years. We applied EE savings of 1.0 percent of load in 2025, 1.5 percent in 2026, and 2.85 percent per year from 2027 to 2038. The decline in load from EE is delayed by a few years in the Full EE case relative to the IRP EE case as well.

Fuel Prices

Synapse used fuel price projections largely based on a similar approach taken by Siemens in its *2018 IRP Fuel Forecast* workbook, developed for PREPA. This includes six base forecasts including those for West Texas Intermediate (WTI) Crude Oil, Henry Hub Natural Gas, Diesel, and Colombian Coal. The delivered fuel price outlooks were derived with assumed adders to reflect contractual pricing agreements applied to the base forecasts. Those adders in particular affect delivered gas prices to San Juan, and to Costa Sur and EcoEléctrica under the revised PPOA and Naturgy gas pricing agreement. The delivered fuel forecasts are applicable to each of PREPA's plants.

Figure 15 shows the process used to derive fuel prices.

Figure 15. Diagram Depicting Fuel Price Derivation



To update the workbook, Synapse used its own projections for Henry Hub natural gas and WTI crude oil prices, which rely on actual historically available data from the U.S. EIA for prior periods,[20,21] a blend of NYMEX forwards in the near term,[22,23] and EIA's *2021 Annual Energy Outlook* in the long term[24]. Figure 16 depicts the sources used to derive the natural gas and oil forecasts.

[20] U.S. Energy Information Administration (EIA). Natural Gas Data. Available at: https://www.eia.gov/dnav/ng/hist/rngwhhdM.htm

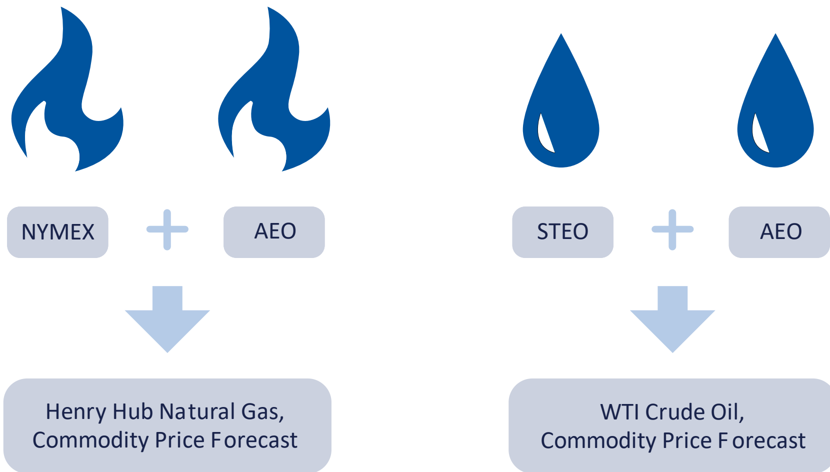
[21] U.S. Energy Information Administration (EIA). Petroleum and Other Liquids Data. Available at: https://www.eia.gov/dnav/pet/pet_pri_spt_s1_m.htm

[22] CME Group. Henry Hub Natural Gas Futures and Options. Available at: https://www.cmegroup.com/trading/energy/natural-gas/natural-gas_quotes_globex.html

[23] CME Group. Crude Oil Futures and Options. Available at: https://www.cmegroup.com/markets/energy/crude-oil/light-sweet-crude.quotes.html

[24] U.S. Energy Information Administration (EIA). Annual Energy Outlook 2021. Table 13. Natural Gas Supply, Disposition, and Prices. Reference Case. Available at: https://www.eia.gov/outlooks/aeo/data/browser/#/?id=13-AEO2021&cases=ref2021&sourcekey=0

Figure 16. Diagrams Depicting Gas and Oil Price Forecast Sources

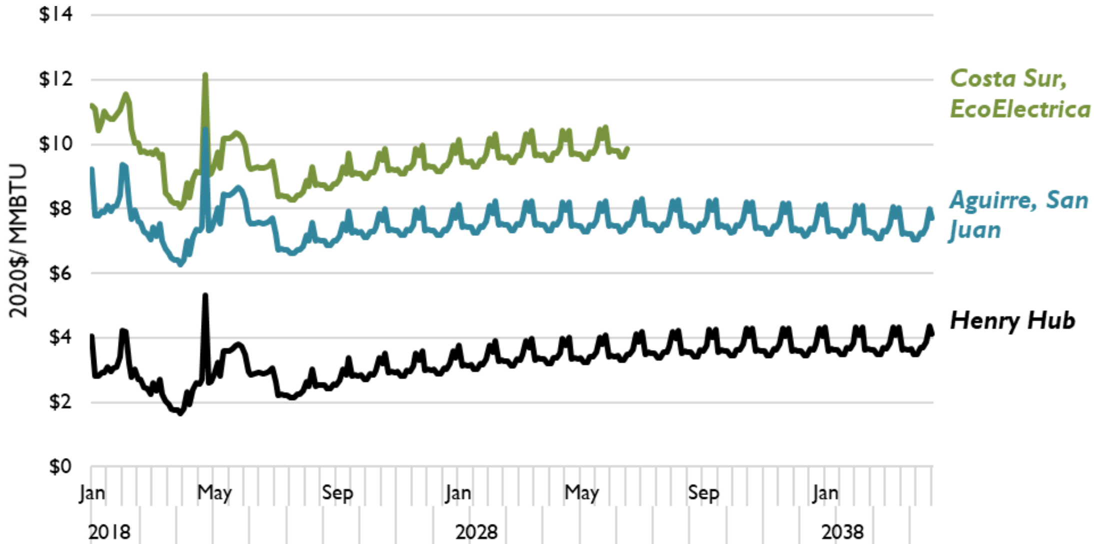


Year	Source
2021	Historical EIA
2022-2023	NYMEX Forwards
2024	Blended NYMEX Forwards and AEO
2025-2038	2021 AEO

Year	Source
2021	Historical EIA
2022-2023	Short Term Energy Outlook (STEO)
2024	Blended STEO and AEO
2025-2038	2021 AEO

The natural gas, oil, and diesel fuel forecasts developed from these sources are shown in Figure 17, Figure 18, and Figure 19, respectively. Siemens had used the Gas Pipeline Competition Model (GPCM) tool to generate its forecasts but also benchmarked it against the NYMEX forwards, while the WTI crude oil price projection was based on averages from multiple sources. In addition to Henry Hub gas prices and WTI oil prices, the other base forecasts largely followed the same approach as Siemens. Base projections for diesel and other fuels rely on a regression of historical WTI crude oil prices to historical diesel prices; Synapse updated these forecasts by including more recent data for the prices and recalculating the regression results. Synapse also updated the delivered fuel price forecasts by ensuring that fuel price projections for future years were reflective of changes to the renegotiated Gas Sales Purchase Agreement (GSPA) between Naturgy Aprovisionamientos S.A. and PREPA.[25] Lastly, Synapse calibrated its forecast to better align with actual fuel receipts and the forecast from Energy Bureau Case No. NEPR-AP-2018-0004, the Unbundling of the Assets of the Puerto Rico Electric Power Authority.

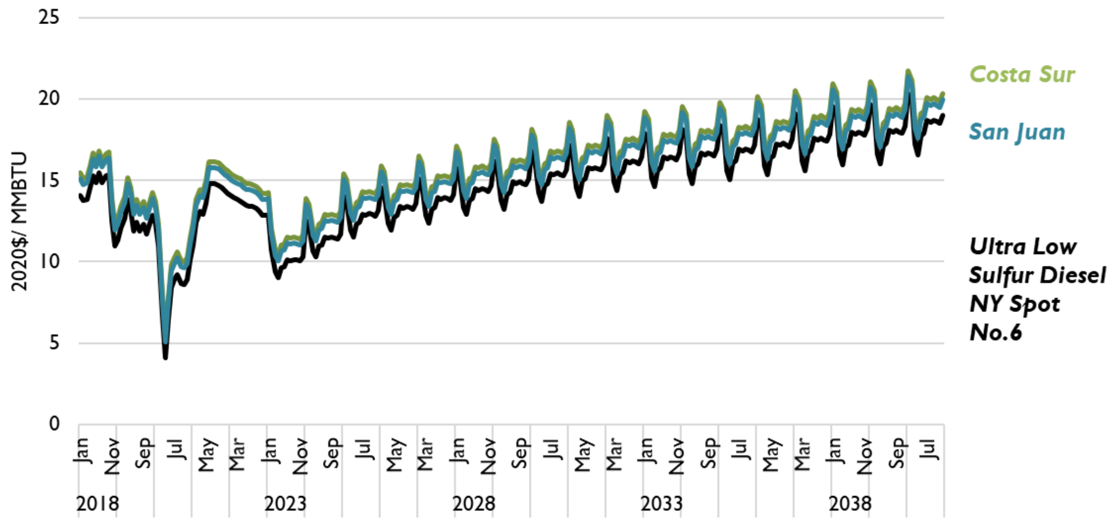
Figure 17. Natural Gas Price Forecast – Henry Hub and Delivered Locations



Source: NYMEX and EIA Annual Energy Outlook.

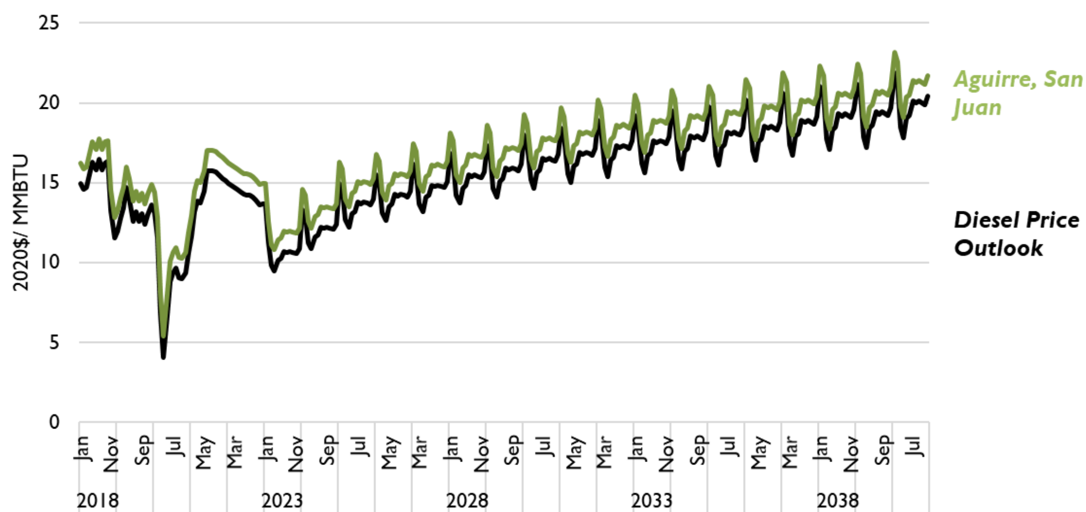
[25] Request for Approval of Amended and Restate Power Purchase and Operating Agreement with EcoEléctrica and Natural Gas Sale and Purchase Agreement with Naturgy, Page 12.

Figure 18. NY Spot No. 6 Fuel Price Forecast – New York Harbor and Delivered Locations



Source: NYMEX and EIA Annual Energy Outlook.

Figure 19. Diesel Fuel Price Forecast



Source: NYMEX and EIA Annual Energy Outlook.

According to the IRP, coal prices were projected based on Siemens's projections for coal prices from the Illinois Basin, and its historical relationship with Colombian coal prices. However, Synapse was unable to obtain the formulas or calculations necessary to see the exact estimation process. Synapse obtained Colombian coal price data from the Colombian Mining Information System[26] and spot prices for the

[26] Sistema de Información Minero Columbiano (SIMCO). Carbón. Available at: https://www1.upme.gov.co/simco/Cifras-Sectoriales/Paginas/carbon.aspx#googtrans/gl/en

Illinois Basin from EIA[27] and found no historical relationship. Given these uncertainties, Synapse maintained the current forecast provided by Siemens.

Renewable Portfolio Standard

Synapse also created a model constraint in EnCompass to reflect Puerto Rico's RPS. The eligible technologies include solar (utility-scale and behind-the-meter), hydro, and wind. The RPS requirements for intermediate years are reflected through linear interpolation of the requirements outlined within Act 17-2019, as shown in Table 13 below.

Table 13. Puerto Rico RPS Targets

Year	Tier 1
2025	40%
2040	60%
2050	100%

Source: Mitigation, Adaptation and Resilience to Climate Change Act (Act 17-2019)

LUMA submitted comments following the 2022 February Avoided Cost Technical conference conducted by Synapse, noting that the linear interpolation method likely does not reflect the true actual schedule. Synapse agrees with this assessment. To better reflect the procurement delays and the general "lumpiness" involved with procuring solar and batteries, Synapse staggered the allowed buildout of solar and batteries. The net impact of this approach has been that the proportion of renewable generation over time follows a non-linear trajectory as seen in Figure 5 and Figure 6, and that the modeling falls short of meeting the 2025 requirement under the No EE and Full EE scenarios.

Energy Resource Mix

Table 14 and Table 15 below provide the resource mix in 2021 in terms of fuel and resource type. PREPA's existing resource capacity is heavily dominated by oil, as the combination of RFO and diesel-based plants comprise 48 percent of existing capacity. However, natural gas and coal serve most of the system's load.

[27] U.S. Energy Information Administration (EIA). Coal Data. Available at: https://www.eia.gov/coal/markets/

Table 14. 2021 PREPA Resource Mix by Fuel

Fuel	Max Capacity (MW)	Proportion of Total Max Capacity
Coal	454	9%
Natural Gas	1,689	35%
Diesel	871	18%
RFO	1,463	30%
Renewable	346	7%
Total	**4,823**	**100%**

Table 15. 2021 PREPA Resource Mix by Resource Type

Resource Type	Max Capacity (MW)	Proportion of Total Max Capacity
Conventional Coal	454	9%
Combined Cycle	1,413	29%
Combustion Turbine	365	8%
Steam Turbine	2,245	47%
Hydroelectric	93	2%
Solar PV	147	3%
Wind	101	2%
Landfill Gas	5	0.1%
Total	**4,823**	**100%**

Unit Retirements

Synapse used a database of electric generation in Puerto Rico created by Horizons Energy. This database uses the 2019 IRP as a foundation for its assumptions regarding the units and corresponding unit attributes in PREPA's system, including anticipated retirements dates for each unit.

As part of the capacity expansion modeling in EnCompass, Synapse also made use of the EnCompass capability to retire units early if found to be economically optimal. We therefore differentiate the two distinct retirement settings as a (i) fixed retirement date and (ii) economic retirement date. A fixed retirement is the date by which the specified unit must be retired by, and a date by which it is no longer able to contribute energy, capacity, or ancillary services to the system. An economic retirement date is a date by which a unit can be considered for retirement if economically optimal for the system.

Both fixed retirement dates and endogenous/economic retirement dates can be set for a single unit. For instance, a thermal unit may have a fixed retirement date in 2035, and an economic retirement date for 2030, which indicates that it can retire up to 5 years early if found to be economically optimal.

Synapse provides the unit retirement settings in Table 16 below. Retirement settings did not vary between the No EE scenario and Full EE scenario, but retirement timing did change slightly.

Table 16. Fixed Retirement Dates and Actual Retirements by Unit

Resource	Must Retire By	Can Retire?	Did Retire?	No EE Retirement	Full EE Retirement	Retired Early in Full EE vs. No EE?
Aguirre 1 CC	2025	Y	N	2025	2025	N
Aguirre 2 CC	2025	Y	N	2025	2025	N
Aguirre GT1 & GT 22	*	Y	Y	2027	2025	Y
Aguirre Steam 1	2025	Y	Y	2025	2024	Y
Aguirre Steam 2	2025	Y	N	2025	2025	N
Cambalache CT 2	2038	N	N	2038	2038	N
Cambalache CT3	2038	N	N	2038	2038	N
Costa Sur 5	2040	Y	Y	2028	2026	Y
Costa Sur 6	2040	Y	Y	2038	2027	Y
Costa Sur GT11 & GT12	2038	Y	Y	2026	2025	Y
Daguao GT11 & GT12	2038	Y	Y	2026	2025	Y
EcoEléctrica	2032	N	N	2032	2032	N
Jobos GT11 & GT12	2038	Y	Y	2026	2025	Y
Mayaguez GT1	2040	N	N	2040	2040	N
Mayaguez GT2	2040	N	N	2040	2040	N
Mayaguez GT3	2040	N	N	2040	2040	N
Mayaguez GT4	2040	N	N	2040	2040	N
Palo Seco 3	2025	Y	Y	2023	2023	N
Palo Seco 4	2025	Y	Y	2023	2023	N
Palo Seco CT11	2025	Y	N	2025	2025	N
Palo Seco CT12	2025	Y	N	2027	2027	N
San Juan 7	2025	Y	Y	2023	2023	N
San Juan 8	2025	Y	Y	2023	2023	N
San Juan 5 CC Conversion	2040	Y	Y	2038	2030	Y
San Juan 6 CC Conversion	2040	Y	Y	2038	2031	Y
Vega Baja GT11 & GT12	*	Y	Y	2026	2024	Y
Yabucoa GT11 & GT12	*	Y	Y	2026	2024	Y

** Resource assumed to be online throughout the modeling period.*

Resource Costs

Synapse used NREL's 2021 ATB data[28] for modeling the capital costs (2020$/$kW_{AC}$) of grid-scale solar (Single-Axis Tracking), grid-scale battery storage (4-hour), and onshore wind. All resource capital costs are based on the moderate case. For the representative combined-cycle gas turbine (CCGT) new resource candidates,[29] we used the capital costs provided by Siemens in the 2019 IRP. Siemens adopted the U.S. Department of Defense Area Cost Factor of 16 percent for Puerto Rico.[30] We remove this locational adder and scale the future capital cost trend for gas units so that it is based on NREL 2021 ATB Data instead of NREL 2018 ATB Data. Table 17 below shows the capital costs for each technology.

[28] National Renewable Energy Laboratory (NREL). (2021). 2021 Annual Technology Baseline (ATB) Cost and Performance Data for Electricity Generation Technologies [data set]. Retrieved from https://dx.doi.org/10.25984/1807473.

[29] Puerto Rico Integrated Resource Plan 2018-2019. Siemens Industry. June 2019. p. 6-11.

[30] Ibid.

Table 17. Capital Costs by Technology (2020$/kW)

Year	Grid-Scale Solar (Single-Axis Tracking)	Grid-Scale Battery (4-hr)	Onshore Wind	CCGT (GE S107F.04)	CCGT (GE LM6000)	CCGT (GE LM2500)	CCGT (GE LM2500+)
2023	$1,184	$1,132	$1,220	$847	$1,431	$1,742	$1,555
2024	$1,125	$1,049	$1,177	$842	$1,425	$1,736	$1,549
2025	$1,065	$967	$1,135	$838	$1,419	$1,730	$1,543
2026	$1,006	$932	$1,092	$834	$1,413	$1,723	$1,536
2027	$946	$897	$1,049	$829	$1,407	$1,717	$1,530
2028	$887	$862	$1,006	$825	$1,401	$1,711	$1,524
2029	$827	$828	$963	$820	$1,394	$1,705	$1,518
2030	$768	$793	$921	$816	$1,388	$1,699	$1,512
2031	$761	$783	$911	$811	$1,382	$1,693	$1,506
2032	$754	$773	$902	$807	$1,376	$1,686	$1,499
2033	$747	$763	$893	$802	$1,370	$1,680	$1,493
2034	$741	$753	$884	$798	$1,364	$1,674	$1,487
2035	$734	$743	$875	$794	$1,357	$1,668	$1,481
2036	$727	$734	$865	$789	$1,351	$1,662	$1,475
2037	$720	$724	$856	$785	$1,345	$1,656	$1,469
2038	$713	$714	$847	$780	$1,339	$1,649	$1,462